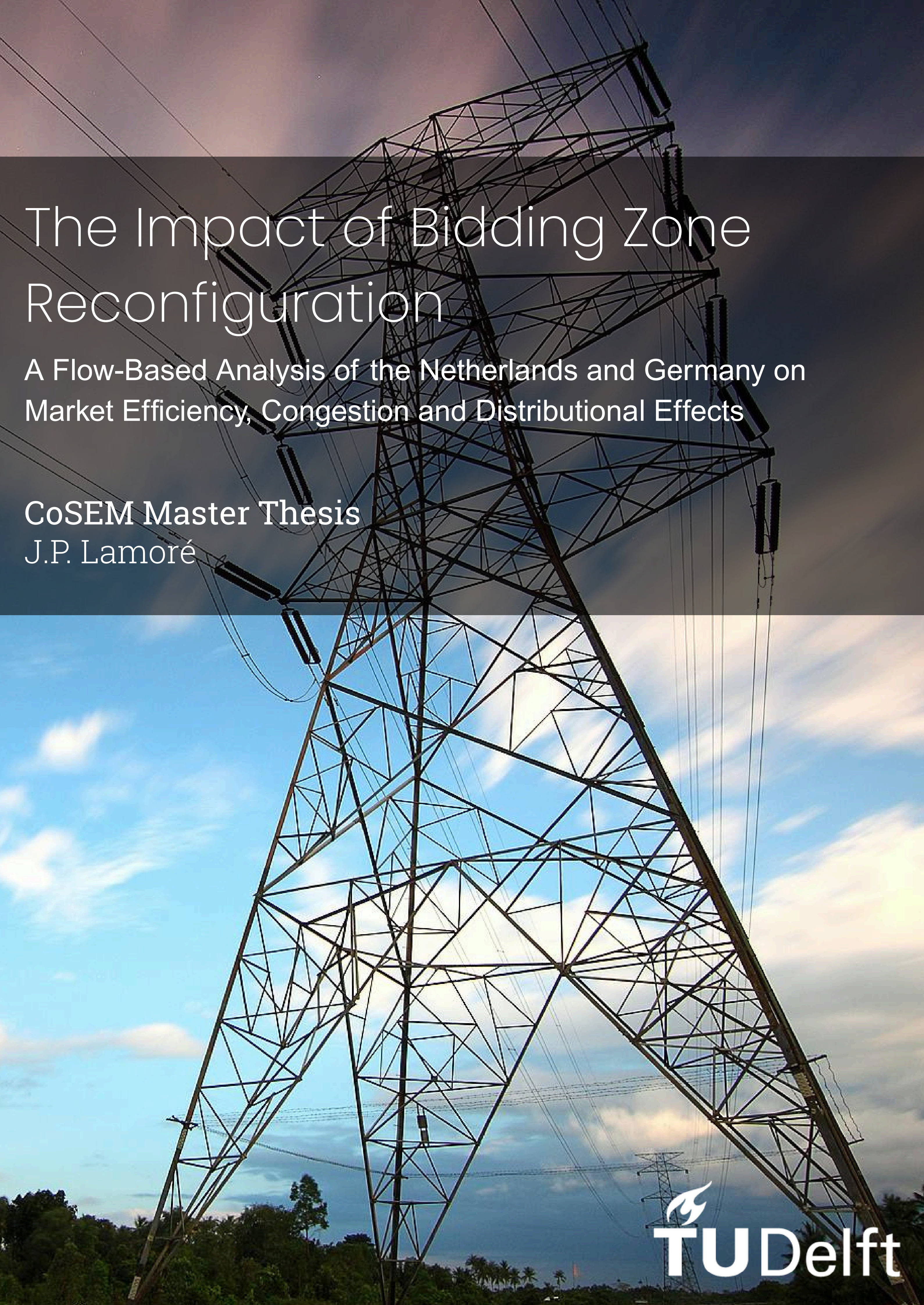
The Impact of Bidding Zone Reconfiguration

A Flow-Based Analysis of the Netherlands and Germany on Market Efficiency, Congestion and Distributional Effects

CoSEM Master Thesis

J.P. Lamoré



TU Delft

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by

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Preface

Writing this thesis has been a long process of ups and downs but has ultimately proven to be a very valuable experience. Looking back, I have very much enjoyed it, although it has certainly been challenging. I'd like to take this chance to briefly acknowledge the people who have greatly helped and made the process enjoyable.

First of all, I'd like to thank my supervisor Kenneth Bruninx, who has from the beginning provided guidance and valuable feedback. You have greatly helped throughout the entire process by making me understand complex concepts and taking the time to explain them. From the conceptualization to the interpretation of results, the provided feedback has been of great value to me.

I would also like to thank my second supervisor, Aad Correljé, who has helped me connect this research to the bigger picture of the energy transition and offered valuable feedback that helped me keep an eye on the broader context, even when I was deep in the details. His perspective added a lot of depth to the thesis.

A big thank you as well to the team at KYOS, where I had the chance to work on this project as a thesis intern. Everyone there was incredibly kind and supportive, and I'm grateful for their interest, enthusiasm, and the time they took to help me. I especially want to mention Lucas and Manuel, thank you both very much for all the discussions, ideas, and practical help along the way.

And of course, I want to thank my friends. I feel very lucky that so many were writing our theses at the same time. Seeing everyone working on their projects with such devotion and going to through the same process together really made the whole experience a lot more fun.

Jens Lamoré
Delft, July 2025

Summary

The increasing congestion on the electricity grid and the delays with respect to electricity grid reinforcement have raised urgent questions about the adequacy of the current zonal pricing model in the Netherlands and Germany. Particularly with the growing share of renewable energy, the assumption of unconstrained internal grids no longer holds, and redispatching has become an expensive and frequent necessity. These developments have sparked interest in the reconfiguration of bidding zones as a potentially more effective alternative to reflect physical constraints and improve market signals.

Although numerous studies have examined the effects of bidding zone reconfigurations, they often focus on specific aspects or national contexts, leaving broader system-wide interactions underexplored. The interconnected nature of the European electricity market means that the changes in one zone are felt across the other zones as well. A system-wide perspective is often disregarded in the existing literature and is necessary to capture how such changes affect congestion, market efficiency, and the distribution of costs and benefits. This is similarly shown through the indicators used within existing literature, these are often tailored to fit the national investigation context and not to the interactions and interdependencies between zones.

This thesis investigates how the reconfiguration of bidding zones in the Netherlands and Germany affects electricity market outcomes within a flow-based coupled market. Amid growing intrazonal congestion and debates on the effectiveness of current market structures, this research addresses the main question:

“How does the reconfiguration of The Dutch and German bidding zones within a flow-based coupled market impact system-wide market efficiency, congestion, and distributional effects?”

To address this question, a flow-based market coupling (FBMC) model was developed using the Exact Projection method within a Lagrangian relaxation and dynamic programming framework. This model was used to simulate various reconfiguration scenarios based on configurations proposed in ACER’s Bidding Zone Review 2. These include a North–South bidding zone split in both the Netherlands and Germany, as well as a simultaneous split in both countries. Model outcomes were compared against findings and insights derived from ENTSO-E’s BZR 2 (2025) and TNO’s 2024 study.

A core contribution of this thesis is the development of a multi-dimensional assessment framework that evaluates system-wide interactions and interdependencies through congestion metrics, market efficiency indicators, and distributional effects. With this framework, the split scenarios have been evaluated, allowing for a system-wide analysis across configurations.

The results demonstrate clear differences in impact across the proposed reconfiguration scenarios. A Dutch North–South split shows only limited system-wide effects: the South sees more extreme price events and increased redispatch, while the North experiences somewhat more stable pricing and marginal improvements in interconnector usage. In contrast, a German North–South split has far-reaching effects, it exposes structural grid bottlenecks in market outcomes, reduces internal redispatch volumes, increases redispatch needs in the Netherlands, and aligns prices more closely with physical grid constraints. Germany-North becomes a low-cost export zone with frequent negative prices, whereas Germany-South faces consistently higher prices and growing import dependence. When both countries are split simultaneously, these dynamics intensify, but the outcomes are largely driven by the German configuration, which dominates the system’s behaviour and distributional effects. The key takeaway is that without a multi-dimensional assessment that includes system interactions and cross-border effects, many of these outcomes would remain unexplained. It is precisely by using complementary metrics that the full picture becomes clear, allowing an explanation of, not just what the results are, but why and how they emerge.

In doing so, this thesis bridges the technical and societal dimensions of electricity market design. It demonstrates that bidding zone reconfigurations are positioned within a deeply interconnected system.

The impacts cannot be adequately captured by a single metric, whether related to congestion, market efficiency, or distributional effects. By incorporating interactions, interdependencies, and cross-zonal dynamics, this research presents a robust, multi-dimensional assessment that captures the full system-wide perspective. In doing so, it provides policymakers, regulators, and system operators with the tools needed to make informed decisions that are aligned with the goals of the sustainable energy transition.

List of Symbols

β Price-sensitivity coefficient linking imbalance to price change

$\Delta\mathrm{Imbalance}_z^h$ Change in zonal imbalance between iterations (MW)

Δ_i^{up}, Δ_i^{down} Ramp-up / ramp-down limits for generator i (MW/h)

δ_N Voltage phase angle at node N (DC power-flow linearisation)

κ Penalty factor used in congestion-surcharge calculation

λ_t Dual variable / marginal price at time t (€/MWh)

$\lambda_{z,t}$ Market-clearing price in zone z at hour t (€/MWh)

$\mathrm{Imbalance}_z^h$ Zonal imbalance of zone z in hour h (MW)

$\mathrm{Import}_{z,t}$, $\mathrm{Export}_{z,t}$ Commercial imports / exports of zone z at hour t (MW)

$\mathrm{NodeScore}_n$ Contribution of node n to line overload

$\mathrm{Overload}_l$ Amount flow on line l exceeds its limit (MW)

$\mathrm{ZoneSurcharge}_z$ Congestion surcharge for zone z

σ_z Congestion surcharge applied to the clearing price in zone z (€/MWh)

τ_t Time a generator has been continuously on/off (h)

tolerance Convergence threshold for price iterations

ε_λ Convergence tolerance for price iteration

A Incidence matrix mapping lines to nodes or zones

a_t Action chosen from state s_t

$A_{l,z}$ Entry of A for line l and zone z

$ATC_{max,l}$ Maximum available transfer capacity on line l (MW)

$ATC_{min,l}$ Minimum available transfer capacity on line l (MW)

B_d Diagonal matrix of line susceptances

B_L Susceptance of line L ($B_L = 1/X_L$)

$C_g(p_{g,t})$ Variable production-cost function of generator g at time t

$C_{i,t}(p_{i,t})$ Cost function of generator i at time t

cap_l Thermal capacity limit of line l (MW)

D_t Total system demand at time t (MW)

$D_{z,t}$ Demand in zone z at hour t (MW)

$F_l^{\max}$ Upper flow limit for line l (MW)

$F_l^{\min}$ Lower flow limit for line l (MW)

F_l^{D-1} Day-ahead flow on line l after capacity allocation

F_l^{D-2} Reference flow on line l (two days ahead)

F_l Actual power flow on line l (MW)

$F_{l,\text{thermal limit}}$ Thermal flow limit of line l (MW)

FRM_l Flow-reliability margin applied to line l (MW)

$G(n)$ Set of generators located at node n

$GSK_{n,z}$ Generation-shift key of node n in zone z

$J_t(s_t)$ Cost-to-go function from state s_t

L_n^h Demand at node n in hour h (MW)

$mP(n)$, $mn(z)$ Mapping sets: nodes in zone z or generators at node n

NEX_z Net-exchange position of zone z (positive = import)

NP_n^h Net injection at node n in hour h (MW)

NTC Net transfer capacity between two areas (MW)

NTF Notified transmission flow already contracted on a corridor

$P_g^{\max}$ Maximum output of generator g (MW)

$P_g^{\min}$ Minimum output of generator g (MW)

$p_{g,t}$ Dispatch level of generator g at hour t (MW)

$p_{i,t}$ Dispatch of generator i at time t (MW)

$PTDF_{l,n}^N$ Node-to-line power-transfer distribution factor

$PTDF_{l,z}^Z$ Zonal PTDF for line l and zone z

Q_g Rated dispatchable capacity of generator g (MW)

Q_n Demand at node n (MW)

$R_g^{\downarrow}$ Ramp-down limit of generator g (MW/h)

$R_g^{\uparrow}$ Ramp-up limit of generator g (MW/h)

$RAM_{t,l}^{neg}$ Negative remaining available margin on line l at time t (MW)

$RAM_{t,l}^{pos}$ Positive remaining available margin on line l at time t (MW)

S_g^{SU}, S_g^{SD} Start-up / shut-down cost for generator g

s_t State vector in dynamic programming at time t

TRM Transmission-reliability margin (uncertainty allowance) (MW)

TTC Total transfer capacity of an interconnector (MW)

$u_{g,t}$ Start-up/shut-down decision variable of generator g at t $(-1, 0, 1)$

$x_{g,t}$ On/off status of generator g at time t (binary)

Contents

1 Introduction

The design of electricity markets is central to ensuring efficient operations, accurate price signals, and resource allocation. The delays on grid expansion and the increasing occurrence of congestion on the existing grid have sparked the discussion about re-assessment of electricity market design within the Netherlands. Due to increasing grid congestion, renewable electricity gets curtailed and investments in renewable electricity projects are struggling to get off the ground (Financieel Dagblad, 2025). TenneT (n.d.) has repeatedly stated that the next years we will have to deal with grid congestion in the Netherlands and Germany as installing more grid capacity is a matter of time. As an alternative way of coping with the increased grid congestion, conversation about the reconfiguration of bidding zones has sparked.

The European Commission defines bidding zones as “the largest geographical area within which market participants are able to exchange energy without capacity allocation (ACER, n.d.).” The delineation of bidding zones is a critical component of electricity market design, as it directly impacts the accuracy of price signals, and the allocation of grid resources. Among the market design approaches, nodal pricing, locational marginal pricing (LMP), is often regarded as the most efficient mechanism. By reflecting local supply, demand, and grid constraints, nodal pricing provides granular price signals reflecting real-time conditions and therefore approaches welfare-optimal market outcomes (Felling et al., 2022). Bidding zones in Europe however have a historical tendency to coincide with national borders within which the prices are uniform, this is called zonal pricing. European electricity markets have favored zonal pricing for its simplicity and alignment with political and regulatory structures (Antonopoulos et al., 2020). A key assumption of zonal pricing is that transmission capacity bottlenecks align with bidding zone borders (Plancke et al., 2016). As a result, each bidding zone is treated as a “copper plate,” implying that electricity can flow freely within the zone without internal constraints (Purchala, 2005). In reality the electricity flows are bounded by the capacities of intrazonal transmission lines. Furthermore, electricity follows Kirchhoff’s laws, meaning that electricity will not flow from source to sink through the shortest path, as is assumed by commercial paths, but will also flow via parallel paths within the electricity grid (Van den Bergh et al., 2016). The commercial capacity within a bidding zone is thus assumed to be infinite whereas the physical capacity is limited.

The transition from conventional generation to renewable generation has exposed these inefficiencies in the zonal pricing model, especially the inability to cope with intrazonal congestion. Unlike conventional generation, which can often be strategically located near demand centers, renewable energy sources such as wind and solar, are geographically dependent and often located far from high-demand areas. This mismatch, particularly in areas where electricity demand and generation do not align, combined with the copper plate approach, leads to intrazonal congestion. To manage the congestion, TenneT, the Dutch transmission system operator, utilizes redispatching. Redispatching refers to the process of adjusting the generation output of power plants to resolve grid congestion while maintaining system stability. This is done by increasing the output of certain generators and simultaneously decreasing the output of others, ensuring that transmission limits are not exceeded. The costs of redispatching are ultimately socialized through transmission tariffs and therefore passed on to consumers (De Vries

L., 2024). Redispatching is costly, in 2023 the redispatching costs in the Netherlands are expected to have been € 470 million as opposed to € 239 million in 2022 (ACM, 2022). The costs associated with redispatching could increase six-fold by 2040 (European Commission, 2024). For Germany the congestion management costs have been estimated to be 1 billion euros in 2023 (Titz et al., 2023).

The limitations of zonal pricing, particularly its inability to fully address intrazonal congestion and reflect accurate price signals, have led to growing discussions on market reconfiguration. While nodal pricing remains the theoretical ideal, transitioning from zonal to nodal systems in Europe faces significant legislative, administrative, and organizational barriers (Eicke & Schittekatte, 2022). Alternatively, reconfiguring existing bidding zones has emerged as a pragmatic approach to addressing market inefficiencies without overhauling the system entirely. Splitting a bidding zone can improve market efficiency as electricity prices better reflect grid congestion within the zone. Splitting bidding zones implies that transmission lines, which were initially intrazonal, become interzonal. The allocation of the interzonal capacity 'cross-border capacity' poses challenges in itself. Currently, the day-ahead cross-border capacity in the CORE region, including the Netherlands and Germany, is calculated by Flow-Based Market Coupling (FBMC) (TenneT, n.d.). This method is designed to enhance cross-border electricity trade by considering the physical constraints of the transmission grid. However, due to uniform pricing, local grid conditions in terms of prices are still not reflected.

The Agency for the Cooperation of Energy Regulators (ACER) has thus initiated the Bidding Zone Review (BZR) to explore potential reconfigurations of bidding zones. The EU legal framework (Regulation - 2015/1222 - EN - EUR-LEX, n.d.) mandates that bidding zones should be defined to ensure efficient congestion management and overall market efficiency, the review therefore aims to address structural and intrazonal congestion. (ACER, 2022). For the Netherlands a split closely aligned with the Northern provinces (Drenthe, Overijssel, Friesland, and Groningen) and the Southern provinces has been proposed. For Germany, four different splits have been proposed in two, three, four or five bidding zones (ACER, 2022). This thesis will investigate the implications of implementing the various bidding zone configurations. In Section 2, the existing relevant literature on the assessment metrics and implications of bidding zone splits will be reviewed. Consecutively, in Section 3, a flow-based market coupling model will be constructed which will be used for modelling the proposed bidding zone splits. In Section 4 the construction of the spatial reconstruction of the European electricity grid will be discussed. In Section 5 the results obtained from the simulation of the various split scenarios will be investigated. Section 6 will be dedicated to discussing the obtained results and Section 7, the last section, will conclude on the analysis and describe the further implications of the research.

1.1. Knowledge Gap

The existing literature on bidding zone reconfigurations in the Netherlands and Germany provides valuable insights into various effects of the reconfigurations. In literature there has been a particular focus on Germany, especially the historical DE-AT-LU split and the hypothetical North-South division have been widely studied. The conducted studies have however often focused on specific aspects or consequences of reconfigurations. For example, Ambrosius et al. (2020) analyze the effect of reconfigurations on investment signals, while Fraunholz et al. (2020) examine outcomes related to expansion planning, congestion management, and price formation. While being valuable contributions, the studies have left the effects of the reconfigurations on neighbouring countries or the emergence of new interactions in the system outside of their scope.

A notable exception is the study by Plancke et al. (2016), which takes a system-wide view. Their work explicitly addresses the interactions between bidding zones and the resulting effects on adjacent electricity markets. This kind of dynamic, interaction-focused analysis is, however, rare in the existing literature.

As for the Netherlands, research is very limited. The only known academic study focusing on a potential Dutch bidding zone split is the master's thesis by Braakman N. (2024), which explores the effects of reconfiguration on commercial cross-border exchanges and electricity prices. There is however an investigation done by TNO (2025) who assess the effects of a German as well as a Dutch bidding zone reconfiguration with a focus on social welfare outcomes and CO_2 emissions. While this is similarly a valuable addition, it too focuses on aggregated welfare outcomes and not explicitly assessing interdependencies or interactions. The Dutch and German reconfigurations have also been studied in the context of the Bidding Zone Review 2 (BZR 2), which this thesis will investigate in more detail in Section 2.3. While the BZR 2 brings together results across different configurations, it too has been subject to criticism for limitations in scope and transparency, and lacks the ability to clearly illustrate how changes in one zone affect another.

To properly assess the system-wide effects and inter-zonal interactions resulting from bidding zone reconfigurations, it is important to do so with respect to the appropriate assessment metrics. While various assessment frameworks exist in the literature (see 2.4), they often rely on general indicators such as aggregated welfare or price averages, which do not capture the dynamic relationships between zones or the redistribution of impacts across borders. As a result, the frameworks currently available fall short when it comes to analysing the system-wide dependencies.

In short, the existing literature clearly identifies several important effects of bidding zone reconfigurations, such as impacts on investment signals, congestion management, and price formation. However, what is not sufficiently addressed is how these reconfigurations affect the broader system and the interactions between zones, the redistribution of effects across borders, and the newly emerging dependencies between bidding areas. Therefore, this thesis proposes a set of assessment metrics which can be used to capture these system-wide dynamics. With these metrics, we will assess several bidding zone reconfiguration scenarios involving the Netherlands and Germany, focusing on how each configuration alters physical flows, market signals, and the distribution of benefits and costs throughout the CORE region. This system-oriented approach enables a more complete understanding of the implications of bidding zone reconfigurations and fills the existing gaps within literature.

1.2. CoSEM Perspective and Societal Relevance

In the Complex Systems Engineering and Management (CoSEM) programme, we are trained to approach challenges in complex socio-technical systems through systems thinking, multi-perspective analysis, and a deep awareness of the interconnectedness between technical, institutional, economic, and societal dimensions. This approach is increasingly important when addressing real-world problems where technological developments do not happen in isolation, but rather in collaboration with societal values, stakeholder perspectives, market rules and system developments. The reconfiguration of bidding zones within a flow-based coupled market is a clear example of such a socio-technical system. Bidding zone reconfigurations are often motivated by technical goals, such as reducing congestion or improving price signals. Yet, they also carry far-reaching social and economic consequences. These changes do not just affect system operators and regulators, but also consumers, producers, and governments across multiple countries. When making informed decisions, the system-wide perspective must be taken into regard as every decision made is going to affect others.

As outlined in the previous section there exists research on several aspects of the reconfiguration of bidding zones. While being precisely what is needed to make informed policy decisions and in order to see the broader picture, the system-wide perspective tends to be neglected. ENTSO-E (2025) itself emphasized this point in the Bidding Zone Review 2, stating that "*conclusions solely based on simulation results are not suitable for decision making when seen in isolation*". The CoSEM point of view and the knowledge gap in the existing literature align in this regard: the need to go beyond isolated outcomes and understand the deeper, interconnected dynamics of the European electricity system.

Understanding the dynamics is especially important because it directly influences how benefits and burdens are distributed across the electricity system. Changes in zone boundaries can alter congestion patterns, price levels, and net positions, resulting in significant shifts in who gains and who loses (Bemš et al., 2016) . Some regions may benefit from lower prices and improved access to renewable energy, while others may face higher import dependency, increased redispatch costs, or exposure to greater price volatility. These outcomes are not just technical characteristics they affect household electricity bills, the competitiveness of industries and investment signals for generation and infrastructure (Ambrosius et al., 2020). The reallocation of such costs and advantages has political, economic, and social implications, particularly in a cross-border context where national interests may conflict. Without a framework that captures these dynamics, policy decisions risk overlooking who is impacted and how, potentially leading to outcomes that are inefficient, inequitable, or unsustainable. This underscores the need for comprehensive evaluation methods that reflect not only system performance, but also the real-world consequences for society.

By taking a system-oriented approach this thesis develops a set of operationalizable assessment metrics which can be used to investigate the effects of bidding zone reconfiguration on the interactions and emerging dynamics in the system rather than on a single assessment metric. Ultimately this thesis aims to contribute to the academic, societal and technical understanding of the impact of bidding zone reconfiguration but also to the policy making process, offering insights that support decision making based on a holistic system-wide perspective and that help realize the energy transition.

1.2.1. KYOS Perspective

As part of this thesis, the research is conducted in collaboration with KYOS Energy Consulting, who have provided access to their proprietary power fundamentals model. This model forms the basis for simulating electricity market outcomes, especially day-ahead prices. KYOS is particularly interested in understanding how the implementation of Flow-Based Market Coupling (FBMC), the real-world capacity allocation method currently used in the CORE region, affects the accuracy and robustness of the model's price signals compared to historical market outcomes. By integrating FBMC into the modelling approach, this research not only investigates the theoretical implications of bidding zone reconfigurations but also explores whether a flow-based representation improves alignment with observed market prices.

1.3. Research Questions and - Approach

To determine the scope and focus of the research, the main- and sub-questions with their respective goal will be stated in the following section.

Main Research Question:

“How does the reconfiguration of The Dutch and German bidding zones within a flow-based coupled market impact system-wide market efficiency, congestion, and distributional effects?”

The main research question will be answered by dividing the associated research into four parts.

Sub-question 1: *”What are the key criteria and assessment metrics for evaluating the impact of reconfiguring the Dutch and German bidding zones on system-wide interactions, considering market efficiency, congestion and distributional effects?”*

The initial literature review will consist of identifying key criteria and assessment metrics for configuration of bidding zones. Existing literature on market coupling and splitting bidding zones will be further investigated. Both historical reconfigurations such as the DE-AT-LU split and hypothetical splits such as that of Germany North-South will be investigated on their used assessment criteria. As was previously identified, the assessment of the system-wide perspective with respective metrics is often neglected. This question facilitates the assessment of interactions and interdependencies by highlighting the metrics needed to do so.

Sub-question 2: *How can a flow-based modeling approach be developed to analyze the effects of bidding zone reconfiguration in The Netherlands and Germany on system-wide interactions with respect to market efficiency, congestion and distributional effects?*

This part of the research will focus on developing a model based on the flow-based modeling approach. First the existing literature on flow based market coupling will be investigated. consequently this sub-question will focus on constructing a model that integrates flow-based capacity allocation, moving beyond the existing available transfer capacity (ATC) method. Given the complexity of the flow-based approach and the lack of full transparency in key data and methodologies, a critical challenge will be using existing data and integrating that into the, to be constructed, model. An overview of the work-flow can be found at the start of the modelling approach (chapter 3), where the methodology will be discussed in depth.

Sub-question 3: *How does the reconfiguration of the Dutch and German bidding zones affect system-wide market efficiency and congestion?*

This question investigates the specific effects of bidding zone reconfigurations on the Dutch and German electricity markets. How the system performs in terms of market efficiency and network security will be answered by integrating the findings from sub-question 1. A bidding zone split may alleviate internal congestion but could also shift congestion patterns to other parts of the grid. Also, a bidding zone split might introduce a differentiation in prices between the newly formed zones possibly leading to (dis)advantages for certain bidding zones. The performance of the newly formed bidding zones will be compared to that of the original bidding zones in order to assess the effects of the reconfiguration.

Sub-question 4: *How does the reconfiguration of the Dutch and German bidding zones affect system-wide zonal market outcomes and system interactions?*

This question examines how the reconfiguration of bidding zones in the Netherlands and Germany affects system-wide zonal distribution effects. We investigate the redistribution of benefits and losses, and how market outcomes differ between high-demand and high-supply areas. Since the Dutch and German power systems are strongly interconnected, changes in one country's zonal layout can significantly alter flow patterns, affect congestion zones, and shift market imbalances. These shifts can redistribute economic benefits and burdens, such as lower prices in exporting zones or increased redispatch needs in congested importing zones.

1.3.1. Research Approach

To answer the research questions, a structured methodological approach is adopted, where each sub-question builds upon the insights gained in the preceding ones.

Sub-question 1 will be addressed through reviewing the existing literature. The aim is to identify and synthesize relevant assessment metrics that have been used in previous studies and regulatory assessments. These include metrics related to market efficiency, congestion, and distributional effects. Particular focus will be given to how these metrics capture system-wide dynamics, such as interzonal interactions and the redistribution of impacts across borders. The results from this review will provide the foundation for evaluating the outcomes of different reconfiguration scenarios in sub-questions 3 and 4.

Sub-question 2 will involve both a literature review and modelling. It focuses on the development of a representative flow-based market coupling model. The literature review will inform the design choices and limitations of flow-based models, while the modelling component will involve constructing a grid representation that incorporates physical constraints and nodal a nodal representation. The model will move beyond the commonly used available transfer capacity (ATC) approach, enabling a realistic representation of cross-zonal flows and constraints. This model will serve as the analytical framework for simulating and evaluating the impacts of different bidding zone configurations in sub-questions 3 and 4.

Sub-question 3 will use the FBMC model and the assessment framework developed in the previous sub-questions to evaluate how different reconfigurations affect market efficiency and congestion. By comparing the performance of current and alternative bidding zone configurations, this step will assess whether reconfigurations lead to improved price signals and reduced internal congestion,.

Sub-question 4 will apply the same model to investigate the distributional impacts of reconfiguration. It will focus on the redistribution of benefits and costs across different zones, shifts in net export/import positions, and emerging interactions between zones. This analysis will be essential for understanding the broader system-wide implications of any proposed reconfiguration.

Together, the outcomes from sub-questions 1 and 2 provide the necessary criteria and modelling framework, while sub-questions 3 and 4 apply these tools to assess performance. This research approach allows for a comprehensive system-wide evaluation of bidding zone reconfiguration scenarios, ultimately the goal is to answer the main research question.

1.4. Conclusion on Chapter 1

In summary, the increasing congestion on the electricity grid and the slow pace of network expansion have raised urgent questions about the adequacy of the current zonal pricing model in the Netherlands and Germany. Particularly with the growing share of renewable energy, the assumption of unconstrained internal grids no longer holds, and redispatching has become an expensive and frequent necessity. These developments have sparked interest in the reconfiguration of bidding zones as a potentially more effective alternative to reflect physical constraints and improve market signals.

Although numerous studies have examined the effects of bidding zone reconfigurations, they often focus on specific aspects or national contexts, leaving broader system-wide interactions underexplored. The interconnected nature of the European electricity market means that the changes in one zone are felt across the other zones as well. A more holistic perspective is needed to capture how such changes affect congestion, market efficiency, and the distribution of costs and benefits across the system. This is similarly shown in the indicators used within existing literature, these are often tailored to fit the national context investigation at hand and not on the interactions between zones.

To address this, the chapter has proposed a set of operational assessment criteria designed to evaluate reconfigurations in terms of market efficiency, congestion patterns, and distributional effects from a system-wide perspective. The subsequent chapters will apply this framework using a flow-based market coupling model to simulate and analyze different bidding zone scenarios for the Netherlands and Germany. This will allow for a deeper understanding of how bidding zone reconfigurations affect the physical and economic realities of the European electricity system.

2 Context and Literature Review

The objective of this chapter is to give an overview of the importance of market coupling and the related existing cross-border capacity allocation methods ATC and FBMC. Both methodologies shall be briefly introduced along with respective limitations and advantages. The reasoning behind the reconfiguration of bidding zones shall be explained and consequently the proposed reconfigurations for the Netherlands and Germany will be introduced.

In order to assess the proposed reconfigurations it is necessary to identify and evaluate the assessment metrics and evaluation criteria used in previous academic and organizational studies related to bidding zone splits and reconfigurations. By synthesizing insights from both forward-looking simulations and ex-post empirical analyses, this review aims to clarify how to assess the impact of bidding zone configurations on several categories.

It will serve as the basis for answering sub-question 1: *"What are the key criteria and assessment metrics for evaluating the impact of reconfiguring the Dutch and German bidding zones on system-wide interactions, considering market efficiency, congestion and distributional effects?"*

2.1. Market coupling and cross-border capacity allocation

Electricity markets across Europe have significantly changed over the past years following the need for increased efficiency and renewable energy integration. Historically, cross-border capacity calculation and electricity trading were separated processes, traders were obliged to first book cross-border capacity and then purchase electricity. This is a system called explicit auctioning (EPEX Spot, n.d.). It creates inefficiencies due to traders thus having to assume and anticipate the required amount of capacity without knowing the final electricity prices. In order to counteract these inefficiencies, market coupling was introduced. Market coupling is a mechanism designed to maximize social welfare and to optimize the use of cross-border capacity (EPEX Spot, n.d.). Market coupling relies on implicit auctioning, the price of the cross-border capacity is integrated into the price calculation for electricity. The integration of different electricity markets into one system allows electricity to flow from bidding zones with lower prices to bidding zones with higher prices, thereby minimizing the price differences between bidding zones (EPEX Spot, n.d.). Market coupling on the day-ahead market was initially introduced in 2006 between the Netherlands, France and Belgium (EPEX Spot, n.d.). The next step consisted of integrating the Central Western Europe (CWE) area within the coupled markets as in 2010 Germany, Luxembourg, and France, joined (TenneT, n.d.). In 2014 the coupled markets were extended to the North West Europe and the South West Europe region.

To achieve the optimal cross-border capacity utilization as sought after by the introduction of market coupling, the available cross-border capacity must be calculated correctly (Van den Bergh et al.,2016). This capacity has traditionally been calculated using the Available Transfer Capacity (ATC) methodology. The calculation of available transfer capacity follows a 4 step approach, all performed by the TSO, which will be shown in the following paragraph. The definitions are derived from the (at that time) European Transmission System Operators Association (ETSO, 2000).

2.1.1. Available Transfer Capacity Methodology

The process begins with the calculation of the Total Transfer Capacity (TTC). The TTC is determined by the physical constraints including thermal limits, voltage limits, and stability limits. With regard to these physical constraints, the TTC represents the ‘maximum feasible power exchange, which can be transmitted between the systems A and B reliably and without affecting the system security.’ (ETSO, 2000). Consequently the Transmission Reliability Margin (TRM) gets calculated by incorporating forecasting uncertainties covering imperfect information availability and external factors. The evaluation is based on probabilities and is done by the TSO which bases the calculation on past events and/or statistical data.

When the TTC and the TRM are calculated, the Net Transfer Capacity is calculated. The NTC is given by the following equation:

$$NTC = TTC - TRM \tag{2.1}$$

And represents the maximum expected amount of electricity that can be transferred between the two systems without causing network constraints in either system, while also accounting for potential uncertainties in future network conditions.

Then to calculate the available transfer capacity the Notified Transmission Flow (NTF), the already occupied fraction of NTC from already accepted transfer contracts, is subtracted from the NTC. Making ATC the ‘transfer capacity remaining available between two interconnected areas’ (ETSO, 2000).

For the electricity flows, the TSOs per country follow a calculation method that adheres to transmission constraints and market-clearing rules (Van den Bergh et al., 2015), defined by the inequality constraint:

$$ATC_l^{\min} \leq F_l \leq ATC_l^{\max} \quad \forall l \tag{2.2}$$

$ATC_l^{\min}$ and $ATC_l^{\max}$ represent the minimum and maximum ATC values in both negative and positive flow directions. F_l is the flow on a transmission link l.

Additionally, the Net Exchange Position (NEX) of each market zone z is calculated using the incidence matrix (Van den Bergh et al., 2015):

$$NEX_z = \sum_l A_{l,z} F_l \quad \forall z \tag{2.3}$$

$A_{l,z}$ is the network incidence matrix, indicating the relationship between cross-border links and market zones. $A_{l,z} = 1$ if the cross-border link l starts in market zone z, $A_{l,z} = -1$ if it ends there, and $A_{l,z} = 0$ if it is not connected to the zone.

The NEX represents the degree to which a zone imports or exports electricity, with a positive position indicating that the zone imports and a negative position that the zone exports (Van den Bergh et al., 2015).

2.1.2. Limitations Available Transfer Capacity and Flow-Based Market Coupling

The ATC approach has several limitations that inhibit it from being an effective cross-border capacity calculation method. It can be seen as a simplistic representation of power flows, assuming that cross-border electricity flows operate independently on each link following the occurred transactions, thereby ignoring potential loop flows (Van den Bergh et al., 2015).

The main limitation inherent to the ATC approach therefore is the inability to account for the difference between the commercial and the physical flow of electricity. The approach assumes these to be equal which is in reality not the case. This shall be illustrated by the following example.

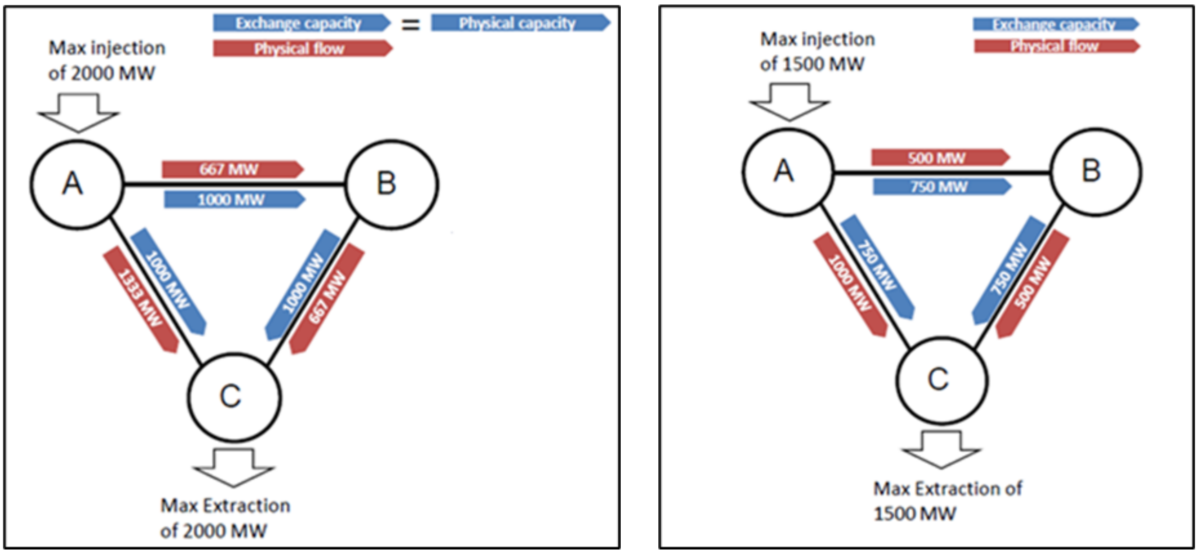


Figure 2.1: Limitation of ATC Nordic CCM project. (2019). *Capacity calculation methodologies explained.* In *Nordic CCM Project.*

In the left-hand scenario of Figure 2.21, market participants are allowed to utilize the maximum exchange capacity on all lines simultaneously. While each individual exchange appears to respect the line limits, the physical flows, which follow Kirchhoff's laws rather than the commercial paths, result in an overload on one of the transmission lines (from A to C). This occurs because the physical power flow does not align with the scheduled commercial exchanges, leading to a security violation. To maintain operational security, the system operator must reduce the exchange capacities. This is shown in the right-hand scenario. Here, the injection and extraction limits are reduced to prevent any physical overloads. While this approach avoids congestion, it leads to underutilization of available physical capacity In other words, the system operates safely but inefficiently.

In order to address this inefficiency, a novel method for calculating cross-border capacity, Flow Based Market Coupling (FBMC), was introduced (TenneT, n.d.). FBMC was initially introduced in the Cen-

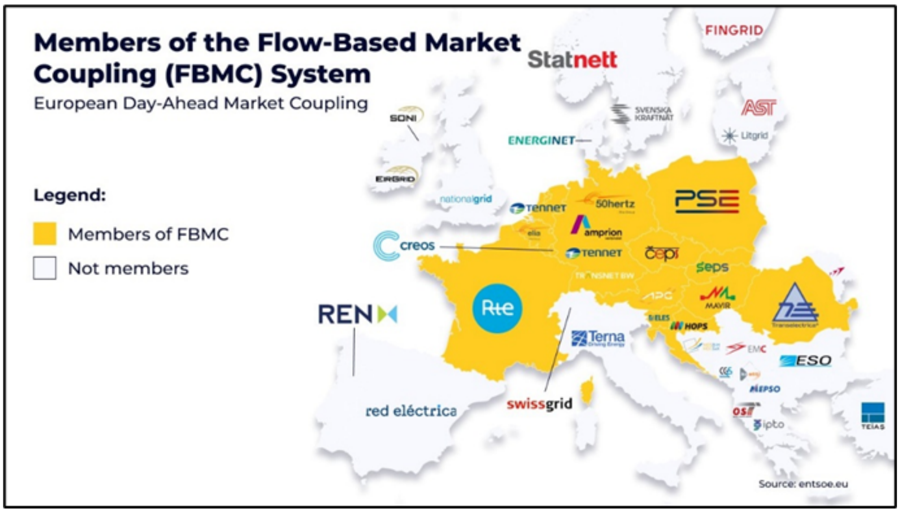


Figure 2.2: , Members of the FBMC system (sourced from :Time2market)

tral West European area in 2015 and in 2022 extended to the CORE region (EpexSpot, 2022) (Figure. 2.2). FBMC is a more advanced and dynamic method as it considers the complete network topology and can account for the interdependencies and dynamic interactions within the power system. Incorporating dynamic interactions is done by utilizing Power Transfer Distribution Factors (PTDFs) which model how electricity flows across the grid and through the calculation of Remaining Available Margins (RAM) which state the actual transmission capacity that can be allocated to the market. The increased accuracy and efficiency however, come at a cost of increased computational complexity. The FBMC methodology used in the CORE region will be described in the following paragraph.

2.1.3. Flow Based Market Coupling Methodology

The following section regarding the flow based market coupling methodology is mainly based on Schönheit et al. (2021) and Van den Bergh et al. (2015). The FBMC process follows an approach carried out by all TSOs individually. The TSOs start by, two days (D-2) ahead of delivery, constructing a base case. The base case serves as a forecast of what the system conditions are expected to be. The inputs include historical data, weather forecasts and predictions of day ahead-generation, demand, grid congestion (JAO, 2022). The TSOs ultimately determine the reference power flows F_l^{ref} on Critical Network Elements (CNE) and the expected net positions of each zone NEX_z (Van den Bergh et al. (2015). These two components, the reference flows and the expected net positions construct the base case (Schönheit et al., 2021).

CNEs are critical lines in the electricity grid which are taken into consideration during the FBMC process (Van den Bergh et al., 2015). Selecting CNEs poses a challenge for TSOs, they are chosen based on their sensitivity to power flows influenced by cross-border trade, TSOs choose this threshold for sensitivity themselves. By varying the zonal generation in a zone z the effects on the flow on line l can be measured. If a transmission element carries a “substantial” portion of electricity flowing between zones it is considered a bottleneck in the system and is designated as a CNE. An important note here is that these lines are not always interzonal lines, but can also be intrazonal lines. In further steps in the process only the critical network elements are considered (Schönheit et al., 2021).

In order to assess the amount of transmission capacity which can be allocated to the market, TSOs must, for every CNE, determine the Remaining Available Margin (RAM) and calculate the Power Transfer Distribution Factors (PTDFs). The PTDF matrix describes how changes in net power injections impact the flows through CNEs (Schönheit et al., 2021), it represents the portion of power flow from source to sink attributed to the corresponding CNE. Nodal PTDFs are derived from the network topology of a network and reflect the fundamental laws governing power flows. In Europe however, due to the zonal market design, zonal PTDF matrices are required for market clearing. In order to derive the zone-to-line PTDF matrix required, the weighted sum of node-to-line $\text{PTDF}_{l,z}^{N}$ for all nodes n is multiplied with the Generation Shift Keys – $\text{GSK}_{n,z}$ functioning as weights. A GSK represents the effect of a power injection at node n relative to the net position of zone z (Schönheit et al., 2021). The GSK values are estimates made by the TSO since the actual GSK values can only be known after market-clearing.

Van den Bergh et al. (2015) represent the GSKs as follows:

$$\mathsf{GSK}_{n,z} = \frac{dP_n}{d\mathsf{NEX}_z} \quad \forall n, \forall z \tag{2.4}$$

Where: NEX_z = Net exchange position of zone z P_n = Production of node n

Following Schönheit et al. (2021), the equation describing the zonal PTDF would then be:

$$\mathsf{PTDF}^{Z}_{l,z} = \sum_{\forall n} \mathsf{GSK}_{n,z} \cdot \mathsf{PTDF}^{N}_{l,n} \tag{2.5}$$

The TSOs must then determine the Remaining Available Margin (RAM) for all CNEs. The RAM is the amount of capacity that can be used for trading on the day-ahead market. Schönheit et al. (2021) describe the equations for the maximum attributable flow for trading on the day ahead market as follows:

$$F_l^{D-1} = F_l^{D-2} + \sum_{z} \mathsf{PTDF}^{Z}_{l,z} \cdot \mathsf{NEX}_{t,z} \tag{2.6}$$

$$-\mathsf{cap}_l - F_l^{D-2} \leq \mathsf{RAM}^{\mathsf{neg}}_{t,l} \leq \Delta F_l^{D-1} \leq \mathsf{RAM}^{\mathsf{pos}}_{t,l} \leq \mathsf{cap}_l - F_l^{D-2} \tag{2.7}$$

Where: F_l^{D-2} is the earlier described F_l^{ref} F_l^{D-1} is the total day-ahead flow $\mathsf{NEX}_{t,z}$ of zone z at time t[1] cap_l is the thermal capacity of line l

The constraints in equation (2.7) ensure that the physical flows on critical network elements on day D remain within the physical capacity limits cap_l, ensuring compliance with the grid's operational constraints. The FBMC methodology is however inherent to limitations related to its dependence on accurate forecasts and the TSOs setting parameters such as Generation Shift Keys and the selection of Critical Network Elements. The aggregation of nodes into zones, the omittance of other lines than CNEs, and the assumptions on which the GSKs are based all introduce a loss of accuracy. To cope with the uncertainty introduced by these practices and to ensure secure operation the TSOs introduce Flow Reliability Margins (FRM). The FRMs represent a deduction, of which the amount is set by the TSO, from the RAM, represented by equations: (Schönheit et al., 2021)

$$\mathsf{RAM}^{\mathsf{pos}}_{t,l} = \mathsf{cap}_l - \mathsf{frm}_l - F_{t,l}^{D-2} \tag{2.8}$$

$$\mathsf{RAM}^{\mathsf{neg}}_{t,l} = -\mathsf{cap}_l + \mathsf{frm}_l - F_{t,l}^{D-2} \tag{2.9}$$

The remaining available margin is therefore limited by the thermal capacity, determined flow reliability margin and the already attributed transmission capacity.

[1] In Schönheit et al. (2021) indicated as $\mathsf{NP}_{t,z}$ but written as $\mathsf{NEX}_{t,z}$ for consistency

2.1.4. Comparison of ATC and FBMC

In existing literature the performance and comparison of FBMC and ATC has been widely covered and the flow based methodology has consistently outperformed the ATC methodology on optimizing cross-border capacity (Ovaere et al., 2023) , (JAO, 2021) (Weinhold & Mieth, 2021). The methodology however also comes with several challenges. FBMC is computationally complex and it requires real-time calculations using advanced optimization models. It is also less intuitive for market participants and overall poorly understood as stated by Kristiansen (2019). This poor understanding also originates from the possibility of non-intuitive flows occurring. All exchanges in a flow-based domain impact other exchanges, since the overall objective is to increase social welfare, it is possible for electricity to flow from high- to low-priced zones, this is a non-intuitive flow which with ATC capacity calculation would be impossible. While counterintuitive from an economic perspective, these flows can increase overall social welfare by relieving congestion on critical network elements and enabling more efficient trades elsewhere in the system (JAO, 2021).

Another challenge originates from the construction of the zonal PTDF matrix and the GSK determination procedure. To determine the GSK values, the net position must already be known. However, the net position is only determined after the market clears, meaning the correct GSK values should already be available (Boury J., 2015). This is a circular dependency forcing TSOs to resort to heuristics and assumptions regarding the GSKs. Additionally, the aggregation of lines in the zone-to-line PTDF matrix to obtain the zonal PTDF matrix (Van den Bergh et al., 2014) makes for a significant loss of information and accuracy.

Despite these challenges, FBMC is still the methodology of choice in the CORE region and unlike ATC, which applies conservative capacity estimates and does not account for network interdependencies, FBMC dynamically adjusts capacity allocations to reflect real-time grid conditions. FBMC provides a more physically accurate representation of the power system by defining a net position domain based on actual power flow sensitivities. Unlike ATC-based approaches, which assume independent commercial exchanges, FBMC incorporates loop flows and network constraints. This results in a larger and more realistic flow-based domain, representing all feasible combinations of zonal net positions that are consistent with physical grid limitations. A larger solution space allows for closer to optimal cross-border capacity allocation, improving overall market efficiency and reducing the need for costly remedial actions, this difference is illustrated in Figure 2.3 which relates to the earlier described flows in Figure 2.1. The blue area described the feasible solution space for FBMC while the grey area represents the ATC solution space.

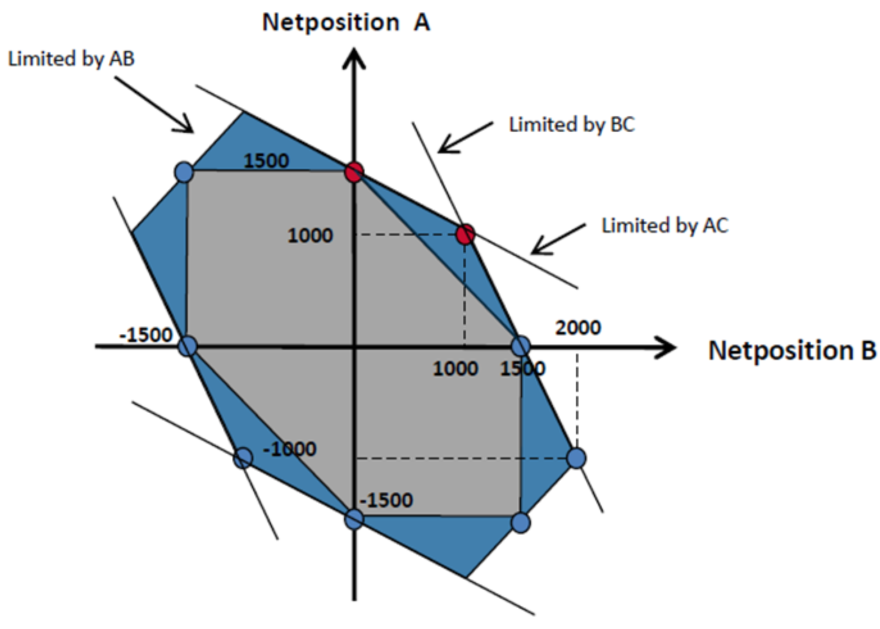


Figure 2.3: Feasible Net Position Domain. Sourced from: Nordic CCM project. (2019). Capacity calculation methodologies explained. In Nordic CCM Project.

2.2. Bidding Zone Reconfiguration

Apart from efficient congestion management, one of the main reasons for bidding zone reconfiguration is the accurate reflection of grid conditions through price signals (Regulation - 2015/1222 - EN - EUR-LEX, 2021.). A nodal market structure is often said to provide the most accurate representation of the real-time cost grid conditions by reflecting local supply, demand, and grid constraints (Plancke et al., 2016). Van den Bergh et al. (2016b) highlight that the market outcomes of a zonal market can improve as the number of bidding zones increases, gradually approaching the efficiency of a nodal system. However, the study also reveals diminishing marginal returns with each additional bidding zone, suggesting that overly granular zone configurations may not justify the associated complexity. Along with European political reservations, a happy medium is the splitting of an existing bidding zone into two or more smaller bidding zones. This has in the past been done already in Sweden and in Italy where the reconfiguration has shown to enhance market efficiency (Wu et al., 2024). An important incentive to split bidding zones is the possible alleviation of structural congestion between network elements. Structural congestion has been defined in the regulation on capacity allocation and congestion management (CACM) as "*congestion in the transmission system that can be unambiguously defined, is predictable, is geographically stable over time and is frequently reoccurring under normal power system conditions*" (Regulation - 2015/1222 - EN - EUR-LEX, 2021.) The CACM Regulation mandates that bidding zones should be defined based on structural congestion rather than political or administrative borders.

A present day hot topic example of structural congestion is the situation in Germany where a possible North-South split is discussed. The North of Germany contains a significant part of the renewable energy available in the country, mostly attributable to wind energy. The South on the other hand contains most of Germany's conventional, more expensive, capacity and a lot of electricity demand. The discrepancy between the high concentration of renewable energy production in the North and the higher electricity demand in the South leads to frequent transmission congestion (Glynos et al., 2024). This mismatch requires expensive re-dispatch measures and calls for a more permanent solution. The tendency of TSOs to limit the amount of cross-border capacity due to the need of utilizing costly redispatch triggered the introduction, not without scrutiny (Potoschnig A., 2020), of a 70% minimum capacity rule in the Clean Energy Package (CEP), requiring that at least 70% of cross-zonal transmission capacity be made available for market trading (ENTSO-E, n.d.). Currently Germany (and Luxembourg) still consists of one bidding zone, the topic of the north-south split in Germany is extensively covered within existing literature due to this debate (Egerer et al., 2016a ; Trepper et al., 2015 ; Plancke et al., 2016; Glynos et al., 2024).

Another prominent example of bidding zone reconfiguration is the German-Austrian bidding zone split. Before the split, electricity flowed freely between Germany and Austria without capacity allocation, despite bottlenecks between the two countries. This resulted in large loop flows affecting Poland and the Czech Republic. A visualization of both a transit and a loop flow is shown in Figure 2.4. A comprehensive review of this split can be found in Braakman (2024). In 2018 the decision was made to split the bidding zones into the DE-LU (Germany-Luxembourg) zone and the AT (Austria) zone.

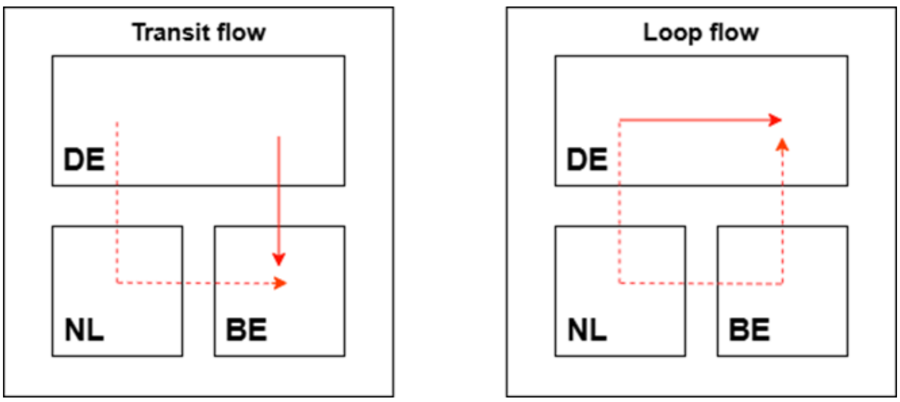


Figure 2.4: Loop and Transit Flow

The European federation of Energy Traders has previously stated that the decision to split the German-Austrian-Luxembourg was made too hastily, without first taking time to properly assess the effects the split would have on the system (European Federation of Energy Traders (EFET), 2019). This statement highlights the importance of proper assessment with the right criteria and metrics, a statement supported by Grimm et al. (2016) who show that bidding zone splitting can lead to decreased welfare if not all factors are considered. They for instance show that market splitting may lead to overinvestment in generation capacity due to incorrectly taking into account the intrazonal transmission constraints. They show that even if at first sight a zone might appear to have sufficient capacity, this might be limited due to ”cyclic flows” which consequently limits the actual available transmission capacity (Grimm et al., 2016).

The configuration of bidding zones has thus shown to be a key factor in electricity market design. Therefore, ACER has the possibility to initiate an assessment of the current bidding zone configuration, a Bidding Zone Review (BZR). This initiation is based on inefficiencies found by ENTSO-E's technical report, or ACER's market report (ACER, n.d.). The BZR aims to provide an assessment of alternative bidding zone configurations that can enhance economic efficiency and facilitate cross-zonal trade, while ensuring the operational security and stability of the electricity grid (TenneT, 2023). The to be investigated bidding zone configurations proposed by ACER include one alternative configuration for the Netherlands and four alternative configurations for Germany, all of which are shown below (Figure 2.5 and 2.6).

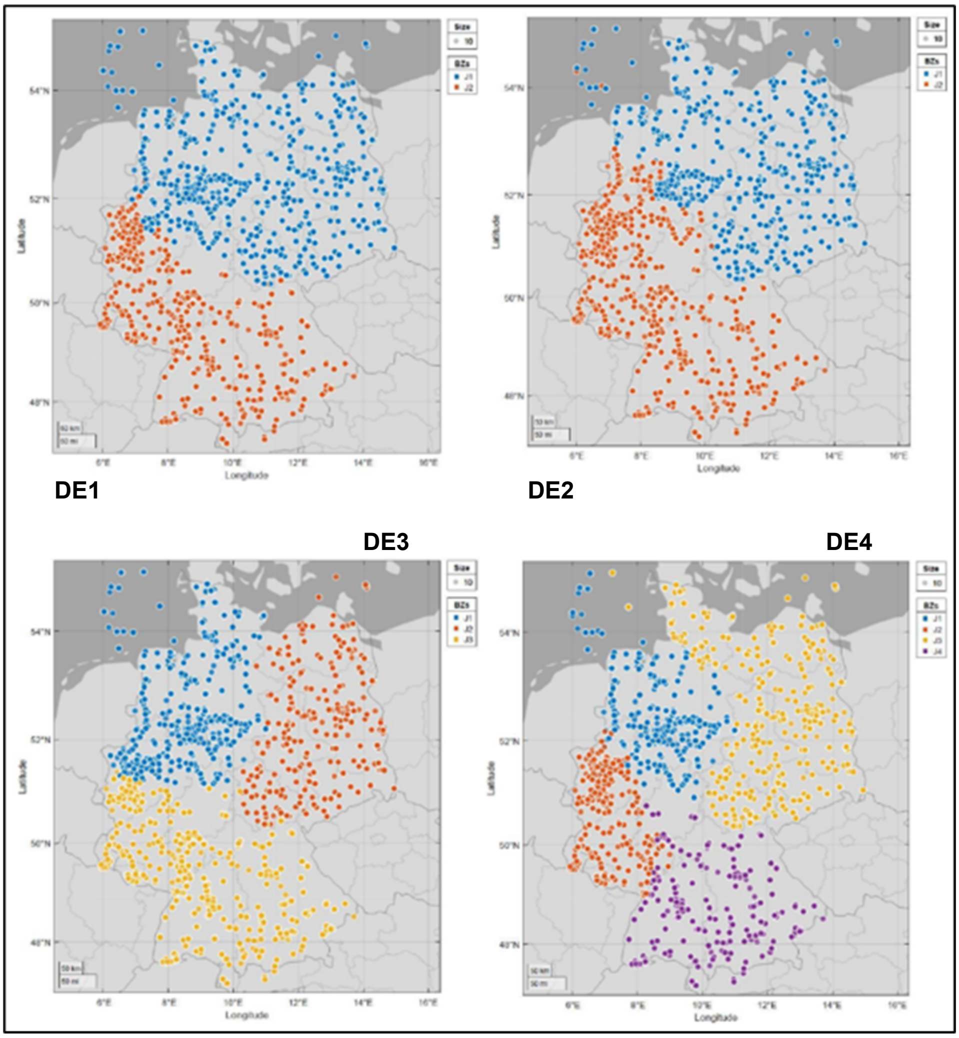


Figure 2.5: Proposed German bidding zone configurations by ACER, sourced from ACER (2022)

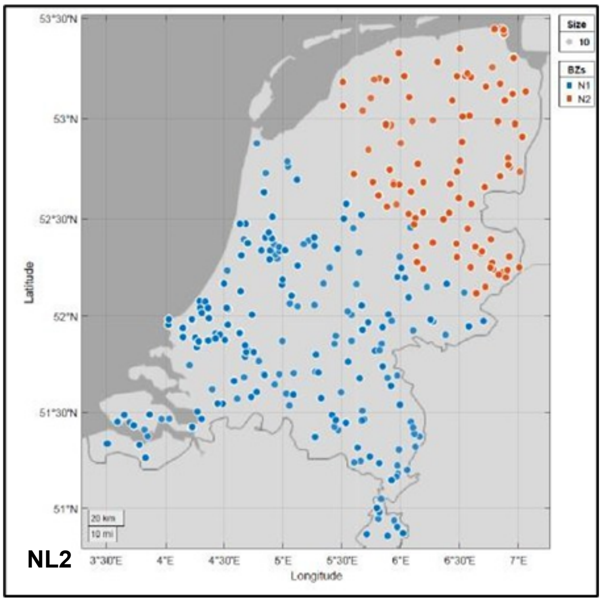


Figure 2.6: Proposed Dutch bidding zone configuration by ACER, sourced from ACER (2022)

2.3. The Bidding Zone Review 2

While writing this the Bidding Zone Review 2 (BZR2) was published by ENTSO-E and ACER. The study was intended to last 12 months but ultimately took 28 months to complete. The final report is a European-wide assessment of various bidding zone configurations including the ones we have shown in Figure 2.5 and 2.6. An important distinction to make is that ACER's goal is to a recommendation, whether or not to split a certain bidding zone. This thesis on the other hand focusses on the interactions in the electricity system and system behaviour, with respective outcomes, when bidding zones are reconfigured. In this sense the BZR 2 serves us not as an answer to questions but it can be used as a benchmark for our results and observed behaviour.

Originally the first BZR was criticized for the that "*the analyses are not supported by comprehensive quantitative simulations*" (ENTSO-E, 2018). The BZR 2 has supported its claims by substantiating them with an extensive modelling approach. Despite this ambition the ultimate deliverable has been criticized on several aspects, especially by German TSOs who "*do not consider the results suitable as a basis for a decision on the reconfiguration of the bidding zone*" (Transnet BW, 2025). One of their main concerns is the outdatedness of input data which was largely created in 2019 (ACER, n.d.). Europex (2025) have in their assessment similarly criticized the BZR 2 on a lack of clarity with respect transmission capacities and several other points. This along with an extensive list of assumptions and limitations poses uncertainty about the accuracy of results. One of these shortcomings which is thoroughly discussed in the limitation sector of the BZR 2, is that "due to technical complexities it was not feasible to robustly quantify several criteria" (ACER, 2025, p.110). The shortcoming for readers being that the assessment criteria are often vaguely or superficially addressed and presented. Superficially or vaguely because the results often only show that a configuration performs " better" or "worse" than the status quo without going into detail. This is similarly a point made by the German TSOs who criticize the BZR 2 for ultimately basing their recommendation solely on economic efficiency in the sense of social welfare, disregarding other needs such as maintaining grid stability.

Despite its limitations the BZR 2 is a very comprehensive and useful report, In this thesis we shall therefore not use it as a result or final authority but as a comparison and benchmark. We are not looking to validate results but to contextualize them and reflect on differences or similarities. Europex similarly share this view and deem the BZR 2 a "*commendable effort*" (Europex, 2025) but also emphasize the need for further analysis and improvements.

An aspect in which the BZR 2 falls short in usefulness for this thesis is the assessment criteria (indicators) used. Potoschnig A. (2020) has deemed the proposed criteria "*unambitious*". The indicators on which the bidding zone configurations are assessed in the BZR have been derived from the CACM regulation. To comply with the CACM, 22 indicators, grouped in 4 categories, are proposed. The indicators with respective category are visualized in Figure 2.7.

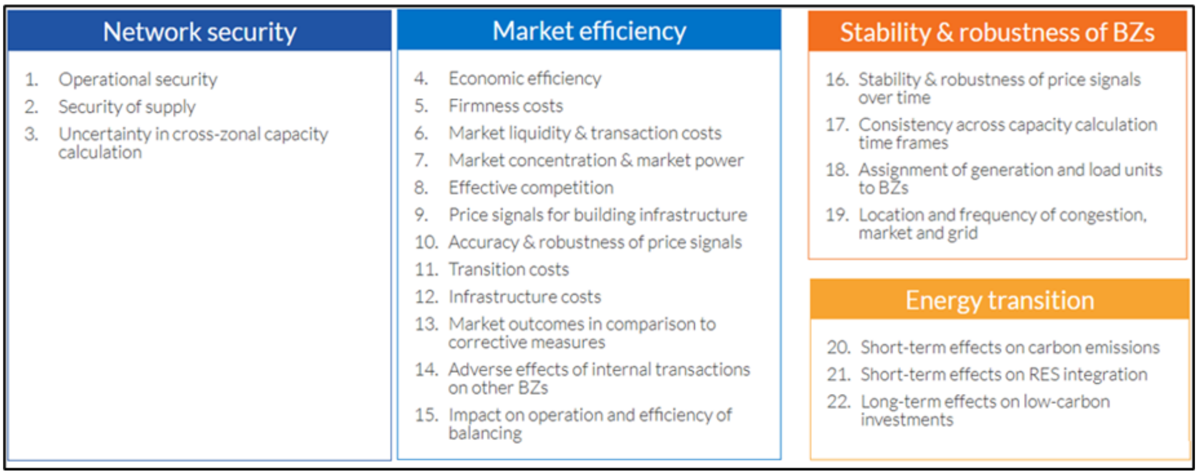


Figure 2.7: Bidding Zone Review indicators, sourced from: ENTSO-E (n.d.)

The first bidding zone review (2018) states that “ *an appropriate review of alternative bidding zone configurations can only be based on a comprehensive assessment that considers all relevant criteria*” (ENTSO-E, 2018).Since the goal of this thesis differs from that of the BZR, and given the critique on the assessment metrics and on how they’ve been presented, a literature review is conducted on the assessment metrics and criteria used to evaluate bidding zone reconfigurations.

2.4. Literature Review on Assessment Criteria

The following section shall give a comprehensive overview of the indicators used within the existing literature on bidding zone configuration and delineation. In order to ultimately answer sub-question 1:" W*hat are the key criteria and assessment metrics for evaluating the impact of bidding zone reconfigurations in the Netherlands and Germany, considering market efficiency, congestion and distributional effects?*" The overview derived from existing literature, combined with the indicators used in the BZR, shall serve as a basis for a selection of criteria which'll be used in this report.

2.4.1. Existing Literature

Existing literature consists of multiple approaches combining forward-looking simulations with backward-looking, empirical evidence based, simulations. A great body of literature exists on how to delineate bidding zones (Chicco et al., 2019) however, we are not conducting an analysis on how to most optimally split based on structural congestion, as the primary focus lies on the results of given configurations. Since the zonal structure influences both market outcomes and grid operations, the focus here, is on how to assess these delineations.

The most prominent works regarding this concept are found to be both Wu et al. (2024) and Brouhard et al. (2020) who advocate for a more standardized approach to market efficiency evaluation, incorporating empirical data and scenario-based modeling. Wu et al. (2024) distinguish between long term effects and short term market efficiency metrics and Brouhard et al. (2020) propose a multi-dimensional framework, integrating economic, technical, and regulatory dimensions. Their approach highlights the need for holistic evaluation and using dynamic market evaluations with grid models. Glynos et al. (2024) share this philosophy and argue also for the integration of RES and grid development into assessments. They too provide a comprehensive framework regarding their proposed indicators including quantitative metrics. Sarfati et al. (2015) propose five indicators for studying market splits. They identify commercial exchange evolution, price convergence and -divergence, loop flows and the evolution of social welfare as main indicators.

Social welfare is found to be the overarching metric in evaluating the effectiveness of electricity market configurations. It is often operationalized as the sum of consumer surplus, producer surplus, and congestion rent and can be seen as a general indicator of the functioning and quality of a market (Sarfati et al., 2015). However, social welfare is an ambiguous term, as is stated by Bemš et al. (2016) who find it "*a measure of well-being*" for society as a whole. They identify economic welfare, and direct and indirect effects on social welfare. Economic welfare refers to the quantifiable market surplus generated through supply and demand interactions, essentially, the sum of consumer and producer surplus and congestion rents. Social welfare, on the other hand, is a broader concept that incorporates not only these direct market outcomes but also indirect effects, externalities, and distributional consequences that do not appear in market transactions. The measurement of indirect effects is more complicated and may include effects on trade possibilities, competitiveness of businesses but also environmental impacts or security of supply. Bemš et al. (2016) conclude with stating that criteria should be simple to use and that the main criteria should be congestion and social welfare as these are the main aspects affected by other underlying criteria.

2.4.2. Market Efficiency

In electricity markets, market efficiency can be seen as the extent to which prices accurately reflect supply and demand, grid constraints and available information. It's primary goal is the efficient allocation of scarce resources. Electricity prices are in this respect a key indicator as they serve as a signal through which social welfare is reflected. Following the description given by Bemš et al. (2016) it relates to the economic welfare aspects of markets and is mostly quantitatively measured. Trepper et al. (2015); Felling et al. (2022); Ambrosius et al. (2020) for instance all focus their assessments mainly on social-economic welfare and marginal / zonal price differences. Graefe (2023) provides an ex-post empirical analysis of the Austria-Germany (DE-AT) split, focusing on how price signals evolved after the reconfiguration. Similarly, Loiacono et al. (2024) employ regression-based methods to analyze the relationship between zonal configurations and price outcomes, using metrics such as average price levels, standard deviation of prices, and the frequency of extreme price events. Sarfati et al. (2015) propose using the metrics price divergence and -convergence between zones and the evolution of social welfare over time. Redispatch costs are regularly mentioned as an indicator for market efficiency, by Zinke (2023) and Grimm et al. (2015) for instance. Redispatching is often seen as an indication of inefficiency, in a zonal market it might increase the amount of available cross-border capacity if integrated in the market clearing and even be beneficial to market outcomes (Poplavskaya et al., 2020). If not integrated in the market clearing however, redispatching shows inefficiencies in market design, as it requires corrective measures to balance supply and demand post-trade, rather than optimizing flows within the market mechanism itself.

The most prominent frameworks concerning market efficiency assessment metrics remain Wu et al. (2024) and Brouhard et al. (2020). Wu et al. (2020) have based their framework on the performance of markets on an economic basis. They differentiate between long-term indicators such as price volatility and congestion rents and short-term indicators such as market liquidity and the performance of a zonal market with a nodal market as benchmark. Congestion rent is further operationalized by Bemš et al. (2016) as the price difference between line end and line start, multiplied by the power flow over that line. Market liquidity measures the ease with which a product is bought and sold without affecting the price significantly, it usually results in a better reflection of the actual worth of a good. A larger bidding zone usually promotes higher market liquidity (Brouhard et al., 2020) whereas a smaller bidding zone has a decreasing effect on market liquidity. Concerning market efficiency, Brouhard et al. (2020) propose quantitative indicators considering market liquidity, market power, and price signals and future investments. Market liquidity can be measured via the Churn rate or the relative liquidity rate. Regarding market power the Herfindahl-Hirschman index is proposed or the Residual Supply Index, both used in the first bidding zone review edition as well, these metrics indicate the degree to which market participants have the ability to influence prices and market dynamics. Brouhard et al. (2020) acknowledge both metrics to be rather basic reflections of market influence and state that market power in electricity markets is often more dependent on system operation.

Ultimately we'd like to measure social welfare however in reality the quantification of social welfare often poses difficulties. These difficulties lie in the definition itself and what is considered to be part of social welfare via different sources, e.g. indirect/direct effects, short/long term effects etcetera. The described components together reflect how well the market is able to allocate resources and can be used as indicators to measure market efficiency.

2.4.3. Congestion Management

Congestion management is apart from social welfare the most often used indicator in existing literature when assessing bidding zone configurations. Congestion is the overarching subject when speaking of loop flows, cross-border capacity calculation, and redispatch volumes or other remedial actions. Redispatch volumes are in existing literature often used as an indicator of the extent to which an electricity system operates efficiently as volumes are of course closely related to the costs of redispatching. Some authors prefer to assess volumes rather than costs such as Trepper et al. (2015) and Fraunholz et al. (2020). Other authors mainly focus on line overloads in combination with redispatch volumes (Felling et al., 2022) or assess the frequency of congestion occurring on certain transmission lines like Wu et al. (2020). Wu et al. (2020) similarly to Bemš et al. (2016) stress the importance of looking at congestion rent, which is the revenue generated from price differences between zones due to transmission constraints and which is collected by TSOs. Androcec and Krajcar (2014) focus on the number of congested hours, the associated congestion costs, and the optimization of transmission capacities.

Ultimately, the metrics regarding redispatch, line overloads, congestion frequency and rent can be traced back to total congestion, measured for instance by Van Den Bergh et al. (2016) and Trepper et al. (2015). Total grid congestion is similarly considered by Glynos et al. (2024) in their framework to evaluate security of supply (SoS) within market splits and they evaluate SoS as a product of four metrics. Total grid congestion is established through looking at the total volume of negative and positive redispatch actions, also including curtailment. The other metrics include Loss of Load Expectation (LOLE) which is an estimation of how many hours per year the generation capacity is not high enough to meet the demand, this closely relates to the metric remaining capacity margin proposed in the first bidding zone review which can be calculated *"by subtracting the maximum available generation capacity from the maximum hourly load per bidding zone"* (ENTSO-E, 2018). Energy not Served (ENS) which measures the energy which is not supplied (demand not met) due to insufficient transmission capacity.

And lastly, the Probability of Load Curtailment (PLC) which represents the probability that the system will be unable to accommodate the load due to a lack of thermal capacity (Glynos et al., 2024). Security of supply is not within the scope of this thesis but would still valuable to assess

Another often utilized assessment method is the investigation of unscheduled flows electricity flows, Graefe (2023) for instance assesses the DE-AT split by analyzing the effects on loop and transit flows. As do Plancke et al. (2016) who analyze the effects of splitting Germany North and South on cross-border flows and interactions with neighboring countries. Out of their five indicators Sarfati et al. (2015) find loop flows one of them, they too differentiate between loop and transit flows. In the assessment we're interested in capturing interdependencies between zones under newly formed configurations and in system behaviour. Therefore, the focus will be on assessing line utilization, redispatch, and newly emerging congestion patterns.

the emergence of loop flows and emerging cross border interactions to create an overview of the physical reality of the network.

2.4.4. Distributional Effects

An important factor when assessing bidding zone reconfigurations is the redistribution of gains, losses and risks. Central to this are the distributional effects, how these benefits, losses and risks are redistributed after system conditions have changed. These impacts consist of effects on system components which are not directly measurable and are closely tied to the indirect effects on social welfare, as described by Bemš et al. (2016). Distributional effects may occur across income groups, regions, economic sectors, different market stakeholder and many more.

Distributional effects are often measured by assessing the changes to other indicators such as electricity prices and redispatch volumes when the system is altered. Egerer et al. (2016) for instance address what the effects on prices and redispatch volumes for consumers and producers are, as do Plancke et al. (2016) investigate the effects on prices for consumers and producers. Trepper et al. (2015) investigate, along with the overall welfare, the prices, redispatch measures, producer- and consumer rents between a North- and South German bidding zone split. Fraunholz et al. (2020) similarly look at a North-South split in Germany through social welfare in terms of consumer and producer rents, but also through a distinction between long- and short-term effects. The authors look at differences in locational prices, required congestion management measures such as redispatch and ultimately at locational investment incentives. Ambrosius et al. (2020) too investigate the effect on investment incentives, welfare, prices and the distribution of these aspects, they do so by modeling regulatory uncertainty.

Literature frequently acknowledges the need for investigation of economic and environmental sustainability, Economic sustainability here refers to the long term resilience of electricity markets. Grimm et al. (2016) for instance show that market splitting may lead to overinvestment, ultimately decreasing welfare. Fraunholz et al. (2020) furthermore show that over time bidding zone configurations become outdated and have to adapt to the changing system conditions. Environmental sustainability then refers to the system's ability to facilitate the integration of renewable energy sources or reduce the emission of greenhouse gasses.

Androcec and Krajcar (2014) stress the importance of incorporating environmental needs into future assessments. Wu et al. (2024) re-iterate this by including a decrease in greenhouse gas emissions in their framework. TNO (2024) have also considered environmental sustainability in their investigation by including the effects that the reconfiguration, as proposed by ACER, have on CO2 emissions. While the literature recognizes the importance of impacts on economic and environmental sustainability, they are often hard to quantify or assess. Transition costs for instance, evaluated in a Compass Lexecon (2023) report for ACER, as part of the BZR, estimates the costs of the transition to the DE2 configuration to be in between €1250 million and €2250 million, a huge range, Bemš et al. (2016) even recommend excluding them from most practical analyses because of this uncertainty.

With respect to the distributional effects we are interested in the changes as opposed to the status quo and the new state of the system under reconfigured bidding zones. Therefore, the emphasis is placed on identifying who benefits and who is disadvantaged under the new configuration. To do so, the changes in zonal electricity prices are investigated, changes in net positions and we identify if any zones become structurally importing or exporting. This assessment will reveal who benefits and who is disadvantaged under the new configuration.

2.4.5. Conclusion on Assessment Criteria

The evaluation of bidding zone configurations is a complex task which requires a combination of using measurable effects and qualitative insight on the associated socio-economic impact. The importance of assessing bidding zone reconfigurations through an appropriate framework is often stressed in literature and by regulatory organizations.

This chapter has served as the basis for answering *sub-question 1:" What are the key criteria and assessment metrics for evaluating the impact of reconfiguring the Dutch and German bidding zones on system-wide interactions, considering market efficiency, congestion, and distributional effects?"*

The first and second bidding zone reviews have been attempts to comprehensively review the performance of several bidding zone configurations. The actual provided assessment has however been subject to significant critique and has been deemed by some stakeholders (see 2.3) "*an insufficient basis for decision making*". Big missing elements, for instance, are the way zones interact and the changes in system behavior due to bidding zone reconfiguration. After stating that the criteria are "*strongly interlinked"* (ENTSOE-E, 2018), the BZR 2 provides little results or investigation to show the related interdependencies and relationships between their indicators. Overall, BZR 2 has thus been deemed useful as a benchmark and for identifying similarities or differences of results, but falls short with respect to being the final authority on outcomes and assessment metrics.

Existing literature however has made valuable contributions to the operationalization of metrics to assess bidding zone configurations. In this thesis we're interested in the system-wide effects of splitting bidding zones and the newly emerged state of the system. A key insight from both existing literature and the BZR 2 is that no single metric can capture the full complexity of bidding zone reconfigurations. While an isolated market efficiency metric for instance can indeed be useful in evaluating the effectiveness of allocating scarce resources, in combination with broader system interactions, it can also be useful to determine the resulting distributional consequences and overall impact. Efficiency metrics should not be interpreted not in isolation, but as part of a wider framework that captures their implications for system-wide outcomes. When these are combined with congestion metrics we can create a clear overview of how well the system functions and what new interactions and inefficiencies arise. This is central to the holistic approach advocated for in Brouhard et al. (2020) and Glynos et al. (2024). We furthermore observe the system in the context of flow-based market coupling, where market performance is shaped by physical constraints and cross-zonal interactions. In the European system, a change in net position in one bidding zone can alter flows and constraints throughout the entire European network. Therefore, assessing the impact of a reconfiguration solely within the borders of one country, such as the Netherlands or Germany, risks missing the full extent of the effects (Plancke et al., 2016).

In conclusion, the assessment framework developed in this thesis is derived from key insights from the academic literature and the practical lessons drawn from the Bidding Zone Review 2. The main takeaway is that no single metric can capture the full system-wide implications of bidding zone reconfiguration. Instead we need a combination of assessment metrics, each capturing a different, but complementary aspect of the system

The three categories of assessment metrics used in this thesis correspond with the previously shown paragraphs, market efficiency, congestion metrics and distributional effects. They have been chosen so that they jointly reflect the physical, economic and distributional consequences of reconfiguring bidding zones. The usefulness lies in the ability to reveal interdependencies that arise in a flow-based, interconnected electricity system. Chapter 3 will detail how these indicators are operationalized to show model outcomes.

Congestion Metrics

The selected congestion metrics are line overloads, utilization rates, and redispatch volumes.

They reflect physical bottlenecks in the electricity grid and are a direct measure of how well the network accommodates market outcomes under new bidding zone configurations. These specific metrics have been selected as they become significantly more informative when placed in a system-wide context. For example, observing increased line overloads in one zone could be misleading if seen in isolation. A holistic analysis might reveal that the congestion is a consequence of reduced loop flows or shifting net positions in neighbouring zones. A zone with high wind electricity generation and limited export capacity for instance may experience frequent overloads causing loop flows elsewhere.

Market Efficiency

Often, the main goal with respect to market efficiency is to measure how efficiently scarce resources are allocated which is often done by measuring social welfare. We've previously described that measuring social welfare in practice is often ambiguous as definitions vary and operationalization is complicated. Therefore it is decided to investigate the system through observable metrics such as price volatility and the frequency of extreme price events. These metrics show what effects bidding zones have on each other pre- and post-split. For instance, a high frequency of negative price hours in one zone could suggest an inability to export excess renewable energy, potentially linked to transmission bottlenecks or poor bidding zone delineation. At the same time, an increase in price volatility in a previously stable zone could indicate increased reliance on imports due to the reconfiguration. These patterns must be linked to the other categories in order to understand what the outcomes mean.

Distributional effects

Distributional effects help answer the question: "*who benefits and who loses after a reconfiguration*". To do so, zonal price levels and net positions are investigated. Rather than being a standalone category, distributional effects serve as the overarching view of the systems interdependencies. For example, a zone which becomes structurally importing after a reconfiguration might enjoy lower average prices, but at the expense of its neighbours who see increased congestion and higher redispatch costs. Or, a zone with significant renewable penetration might become a big exporter, which reduces its own prices but increases congestion in other parts of the network. Only by combining congestion and market efficiency metrics with distributional effects can these underlying patterns be fully revealed.

Category	Chosen Metrics
Congestion Metrics	• Line overloads • Utilization rates • Redispatch volumes
Market Efficiency	• Price volatility • Frequency of extreme price events (e.g., negative prices or extremely high)
Distributional Effects	• Zonal price levels • Net positions

Table 2.1: Overview of selected metrics by category

These metrics were chosen because they are not only operationalizable but also well suited to investigate the complex inter-zonal dynamics that define flow-based market coupling. Their interactions help reveal the broader, system-wide picture: where physical constraints arise, how they shape prices and dispatch, and how the resulting costs and benefits are distributed. The metrics do not function in isolation but reinforce and contextualize each other which facilitates capturing the full impact of bidding zone reconfiguration in an interconnected power system.

3 Methodology

This chapter presents the methodology and theories applied to simulate and analyze the outcomes of the electricity market under different bidding zone configurations in the Netherlands and Germany. The primary objective is to extend the existing commercial market model by implementing FBMC.

In doing so, sub-question 2: *”How can a flow-based modeling approach be developed to analyze the effects of bidding zone reconfiguration in The Netherlands and Germany on system-wide interactions with respect to market efficiency, congestion and distributional effects?* ” will be answered.

The chapter starts with a detailed explanation of the existing market model, highlighting its goal, existing workflow and pricing mechanism. The reasons behind selecting Lagrangian relaxation for the initial model, namely its computational efficiency, is then elaborated upon, alongside an examination of the method’s suitability and limitations. Subsequently, the proposed implementation strategy is outlined to enhance the current model to effectively incorporate a flow-based representation. This strategy includes the introduction of the Exact Projection theory (Aravena et al., 2021), which mathematically approaches the flow-based methodology. The Exact Projection method is elaborated upon and the implementation into the current model is discussed.

3.1. Explanation of The Current Model

The current model is designed primarily to simulate hourly electricity prices within a zonal market configuration. Each bidding zone is represented as an aggregation of all that zone’s properties, such as internal generation and demand, into single, zonal values. Cross-border exchanges between bidding zones are treated strictly as commercial transactions, aggregated to reflect total cross-zonal flows aimed at maximizing price convergence. The model does not include detailed grid topology or explicit physical characteristics, such as internal transmission constraints or a nodal representation. Instead, it adopts the Available Transfer Capacity (ATC) method, using predefined maximum import and export capacities between zones as its only ‘physical’ limitation. In all following explanations when the ‘ATC model’ is mentioned it is a reference to the original model.

Key inputs to the model include residual load (defined as load minus variable renewable generation), detailed technical and economic parameters for thermal generation units (capacity, ramp rates, costs, and constraints), fuel and CO_2 prices, and interzonal transmission capacities. The data necessary for model initialization is provided by KYOS and sourced through various publicly available databases such as ENTSO-E and TSOs.

At its core, the model employs an Economic Dispatch (ED) / Unit Commitment (UC) approach, aiming to meet electricity demand at the lowest possible cost within operational constraints. Economic dispatch refers to the process of determining the optimal output level for each generator, such that total system demand is met at the lowest possible operational cost, while respecting generator constraints such as minimum/maximum output and ramp rates. The UC formulation explicitly models binary generator decisions (on/off states) alongside dispatch levels.

To solve the model, a Lagrangian relaxation approach is used, where deviations from the power balance constraint are penalized, imbalance that is, *(section 3.1.1 elaborates)*. The relaxation transforms the original problem into a dual formulation, decomposed into market-specific subproblems that enforce operational constraints, such as ramping limits, ensuring realistic dispatch outcomes. The economic dispatch component of these subproblems is solved using dynamic programming (DP) for each individual generating unit.

Dynamic programming is an optimization technique used to solve sequential decision problems by breaking them down into simpler subproblems. In the context of electricity market modeling, DP is particularly well-suited to the unit commitment problem, where individual generators must decide when to switch on or off and how much power to produce over a time horizon, while satisfying the associated technical constraints.

The generator-level unit commitment problem is sequential, this means that decisions made in one hour, e.g. whether or not to start up or shut down affect the feasible options the generator has in the subsequent hour. DP addresses this by systematically evaluating all possible decisions at each time step, storing intermediate results (costs and actions) and reusing them to construct the overall optimal solution efficiently.

The solution proceeds in two phases:

- In the **backward recursion**, DP starts at the final hour and proceeds backward in time. For each state at each hour, it calculates the minimum achievable cost-to-go by evaluating all admissible actions (these are the actions for which the constraints are satisfied) and it selects the one that minimizes the sum of cost and the future cost-to-go from the resulting next state. This cost-minimizing action is called the *argmin* (argument of the minimum) and is stored for use in the forward pass.
- In the **forward pass**, the algorithm starts from the known initial state and applies the sequence of stored argmin actions at each step to reconstruct the optimal dispatch and commitment schedule over the full time horizon.

Because the number of legal states and actions is finite, the DP approach can solve the generator subproblem with high computational efficiency. Section 3.1.2. elaborates on the model workflow.

3.1.1. Lagrangian Relaxation and Model Workflow

The decision to use Lagrangian relaxation in the current model was primarily motivated by its computational efficiency and compatibility with commercial market applications. For commercial electricity market modelling, where the objective is not necessarily to obtain strictly feasible solutions but rather to simulate hourly prices, this approach is suitable. Since feasibility is not a strict requirement in the market context, and prices are adjusted iteratively through imbalance penalties, it enables rapid convergence of market-clearing prices.

The imbalance pricing is central to the iterative process, adjusting prices based on deviations from system balance. If generation within a market does not match its demand, prices are adjusted accordingly, rising when generation is insufficient to incentivize additional dispatch, and falling when there is excess generation to encourage reduced output. Over successive iterations, the model continuously recalculates zonal prices and imbalances until a converged state is reached. At convergence, the differences between consecutive price iterations $\Delta\lambda_{z,t}^{(k)}$ are sufficiently small, ensuring that the market balance constraints (load equals production) are ultimately satisfied. Since the model is made available by KYOS, comments on the exact optimization equations cannot be given. Instead, a general form of the optimization problem and its associated dual constraint is presented, based on Virmani et al. (1989).

Objective function:

$$\min \sum_{i,t} C_{i,t}(p_{i,t}) \tag{3.1}$$

System balance constraint:

$$\sum_{i} p_{i,t} = D_t \quad \forall t \tag{3.2}$$

Generation limits constraint:

$$P_i^{\min} \leq p_{i,t} \leq P_i^{\max} \quad \forall i, t \tag{3.3}$$

Ramping constraints:

$$-\Delta_i^{\text{down}} \leq p_{i,t} - p_{i,t-1} \leq \Delta_i^{\text{up}} \quad \forall i, t \tag{3.4}$$

Where: $C_{i,t}(p_{i,t})$ is the production cost function of generator i at time t. $p_{i,t}$ is the generation output of unit i at time t. D_t is the total system demand at time t. $P_i^{\min}, P_i^{\max}$ represent minimum and maximum generation limits respectively for generator i. $\Delta_i^{\text{up}}, \Delta_i^{\text{down}}$ represent ramp-up and ramp-down constraints respectively.

Equation (3.5) shows the partial Lagrangian associated with the hereabove introduced problem. Here, λ_t represents the dual variable (or shadow price) associated with the system-level demand constraint at time t. Intuitively, λ_t is the marginal cost of meeting demand at time t.

$$\mathcal{L}(p, \lambda) = \sum_{i,t} C_{i,t}(p_{i,t}) + \sum_{t} \lambda_t \left(D_t - \sum_{i} p_{i,t} \right) \tag{3.5}$$

Note that this formulation applies at the zonal level, where each zone is balanced independently. The dual variable λ_t can thus be interpreted as the zonal marginal price.

The iterative pricing and dispatch mechanism is illustrated in Figure 3.1 and similarly based on the workflow illustrated in Virmani et al. (1989). The pricing mechanism will later be explained in more detail. To aid the understanding of the model workflow we'll 'walk- through' the mechanism in the following paragraph. The equations presented and mechanism described have been derived from (Guan et al., 1992).

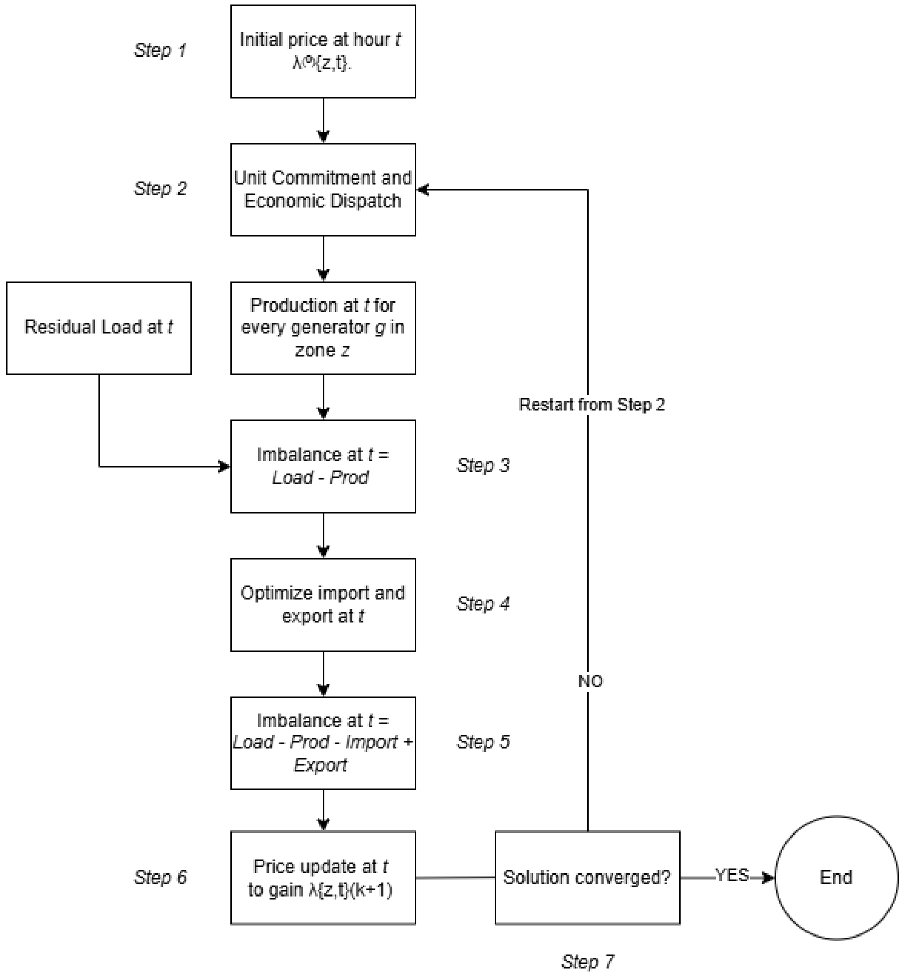


Figure 3.1: High Level Model Workflow, Iterative Mechanism

3.1.2. Iterative Mechanism Walkthrough

The following steps correspond to the steps shown in figure 3.1 and describe the flow presented in the figure.

Step 1: Initial price $\lambda^{(0)}$

To start, for every hour t, the ramping and on/off restrictions are ignored. Power plants are then sorted by *merit-order*, this is a way of ranking power plants by variable costs, from lowest to highest. The generators adjust their output to $P^{\max}$ until zonal demand $D_{z,t}$ is met. The marginal unit's (the last generator to turn on to meet demand) cost becomes the starting price, the warm start price $\lambda_{z,t}^{(0)}$.

Step 2: Unit Commitment and Economic Dispatch with Dynamic Programming

With the initial prices set, each generator solves its own dispatch and commitment schedule using dynamic programming. This captures all technical constraints and allows for generator-level decision-making based on the price signal in that specific hour.

The subproblem which is solved by each generator individually is shown here in simple terms, the symbols used have been altered to be consistent within this thesis and differ from what is originally presented in Guan et al. (1992):

$$\text{SUB Problem}_g: \quad \min_{p_g, x_g, u_g} \sum_{t=1}^{T} \left[C_g(p_{g,t}) - \lambda_{g,t}^{(k)} p_{g,t} + S_g(x_{g,t}, u_{g,t}) \right] \tag{3.1}$$

$$\text{s.t. } x_{t+1} = x_t + u_t, \; u_t \in \{-1, 0, 1\}, \tag{3.2}$$

$$x_t P_g^{\min} \leq p_{g,t} \leq x_t P_g^{\max}, \tag{3.3}$$

$$-R_g^{\downarrow} \leq p_{g,t} - p_{g,t-1} \leq R_g^{\uparrow}, \tag{3.4}$$

Where:

- $p_{g,t}$: Power output of generator g at time t.
- $x_{g,t} \in \{0, 1\}$: On/off status of generator g at time t (1 if on, 0 if off).
- $u_{g,t} \in \{-1, 0, +1\}$: Transition variable; $+1$ for start-up, -1 for shut-down, 0 if status remains unchanged.
- $C_g(p_{g,t}) = c_g p_{g,t}$: Variable production cost for output $p_{g,t}$.
- $\lambda_{g,t}^{(k)}$: Zonal market price at time t in iteration k, received by generator g.
- $\lambda_{g,t}^{(k)} p_{g,t}$: Revenue earned by generator g at time t (price times output).
- $S_g(x_{g,t}, u_{g,t})$: Commitment cost:

$$S_g(x_t, u_t) = \begin{cases} S_g^{\text{SU}}, & u_t = +1 \quad \text{(start-up)} \\ S_g^{\text{SD}}, & u_t = -1 \quad \text{(shut-down)} \\ 0, & u_t = 0 \quad \text{(stay on/off)} \end{cases}$$

- $P_g^{\min}, P_g^{\max}$: Minimum and maximum generation limits for generator g.
- $R_g^{\uparrow}, R_g^{\downarrow}$: Ramp-up and ramp-down limits.

Solving The Subproblem

The goal of the dynamic programming approach is to determine the optimal on/off schedule and dispatch levels for a single generator. At each time step t, the algorithm evaluates the best decision the generator can make, whether to turn on, stay on, shut down, or remain off, in order to minimize the total cost over the horizon.

To do so, the DP tracks the generator's situation through a **state** variable, this represents the current situation which the generator is in:

$$s_t = (x_t, \tau_t, p_{t-1}) \tag{3.5}$$

where:

- $x_t \in \{0, 1\}$ is the generator's on/off status at the beginning of hour t,
- τ_t is the number of hours the generator has been continuously ON or OFF (to enforce minimum up/down time constraints),
- p_{t-1} is the power output in the previous hour, required to enforce ramping constraints.

From each state s_t, the generator chooses an **action**:

$$a_t = (x_{t+1}, p_t) \tag{3.6}$$

representing the decision to be online or offline in the next hour (x_{t+1}) and, if online, how much power to produce p_t. This decision must of course comply with the associated technical constraints of the specific generator.

Every action a generator then decides to make, incurs a **stage cost**:

$$c_t(s_t, a_t) = C_g(p_t) - \lambda_{g,t} \cdot p_t + S_g(x_t, u_t) \tag{3.7}$$

where:

- $C_g(p_t)$ is the variable production cost,
- $\lambda_{g,t} \cdot p_t$ is the revenue at time t,
- $S_g(x_t, u_t)$ is the commitment cost (start-up or shut-down), depending on the transition in status.

Remember that this problem is solved in two phases. First, the backward recursion computes the minimum total cost from each possible state by exploring all feasible actions. The backward recursion thus makes a path from the end (of the time horizon) to the start. This path is formed by evaluating the *cost-to-go function*:

$$J_t(s_t) = \min_{a_t \in \mathcal{A}(s_t)} \left[c_t(s_t, a_t) + J_{t+1}(s_{t+1}) \right], \quad \text{with } J_{T+1} \equiv 0 \tag{3.8}$$

which expresses the minimum cost achievable when coming from state s_t at time t until the end of the horizon. For each possible state, the algorithm ”remembers” the minimizing action (the *argmin*) that leads to the lowest total cost, i.e., the minimum-cost path going backward through time.

Then, in the second phase, the forward pass, the algorithm starts from the known initial state (x_1, τ_1, p_0) and follows the remembered minimizing actions a_t^* step by step. This reconstructs the optimal dispatch and commitment schedule over time, effectively following the minimum-cost path from start to finish:

$$\{x_{g,t}^*,\ p_{g,t}^*\}_{t=1}^T \tag{3.9}$$

The algorithm ends up with a complete generation schedule that satisfies all operational constraints and minimizes total cost in response to the given price signal.

Step 3: Compute initial zonal imbalance

After solving all generator subproblems, the imbalance in each zone is computed, the production from each generator comes from the previous step, the demand is a model input:

$$\Delta_{z,t}^{\text{pre},(k)} = D_{z,t} - \sum_{g \in z} p_{g,t}^{(k)} \tag{3.10}$$

Step 4: ATC-based flow computation

Determine interzonal net exchanges $f_{\ell,t}^{(k)}$ based on available transfer capacities (ATC) and net imbalance signals. The flows in the original model are computed based on price signals and aim to optimize price convergence, electricity can therefore also only flow from low-priced zones to high(er)-priced zones.

The flows are subject to the maximum interconnection capacities between zones:

$$-F_\ell^{\max} \leq f_{\ell,t}^{(k)} \leq F_\ell^{\max} \tag{3.11}$$

Step 5: Re-compute imbalance after trade

The updated imbalance in each zone is computed and consists of both internal generation and net interzonal exchanges. Imports reduce the imbalance (i.e., help meet demand), while exports worsen it (i.e., reduce available local supply):

$$\Delta_{z,t}^{(k)} = D_{z,t} - \sum_{g \in z} p_{g,t}^{(k)} - \text{Import}_{z,t}^{(k)} + \text{Export}_{z,t}^{(k)} \tag{3.12}$$

Step 6: Price update

The price from the previous iteration (or from the warm start) is updated according to the computed imbalance:

$$\lambda_{z,t}^{(k+1)} = \lambda_{z,t}^{(k)} + \beta\,\Delta_{z,t}^{(k)} \tag{3.13}$$

Step 7: Convergence check

The algorithm checks whether or not the change in overall price is below the stopping threshold, if so, the algorithm stops:

$$\left|\lambda_{z,t}^{(k+1)} - \lambda_{z,t}^{(k)}\right| < \text{tolerance} \tag{3.14}$$

Otherwise, we continue to iteration $k+1.$ and repeat from Step 2.

3.1.3. Suitability and Limitations

Before continuing with the proposed initial model, a brief reflection on the choice of Lagrangian relaxation and its suitability for the purposes of this project is needed. As outlined earlier, the model is based on a commercial market design that prioritizes computational efficiency in simulating hourly electricity prices over enforcing full physical feasibility. In this context, LR combined with dynamic programming has long been regarded as a very suitable approach for solving unit commitment and economic dispatch problems, particularly in systems with many thermal generators and complex inter-temporal constraints.

Odunlami & Adebisi (2025) provide a comparative evaluation of conventional optimization techniques for UC/ED, benchmarking several methods. They assess MILP, DP, LR and CLP based on ”*practical considerations, cost effectiveness, and computational performance*”. Their results indicate that LR–DP consistently performs well, particularly in systems with complex unit-specific constraints like ramping limits, minimum up/down times, and start-up costs. While MILP achieves the lowest total cost, LR–DP achieves an overall balance between operational feasibility, computational tractability and cost effectiveness.

Most applications of Lagrangian relaxation for economic dispatch and unit commitment have however assumed either copper-plate power systems or the ATC methodology, thus ignoring the full complexity of modern flow-based market coupling used in European electricity markets. Wyrwoll et al. (2023) address this gap by proposing a market-clearing model that integrates FBMC directly into a Lagrangian-relaxed framework. Their model is implemented in a single-stage structure, where both unit-level commitment and dispatch decisions and network constraints from FBMC are co-optimized within one iterative loop. Prior to their work, they report having found no existing literature combining UC/ED, LR, and FBMC in this manner. Consequently, they describe their implementation as a “*proof of concept*”. Their results demonstrate that such a single-stage approach is not only computationally feasible but also capable of producing realistic and consistent market outcomes.

With respect to limitations, the most prominent issue inherent to Lagrangian relaxation is the presence of a duality gap. The duality gap refers to the difference between the best solution found by the relaxed (dual) problem and the actual optimal solution of the original (primal) problem. As a result, the relaxed model may find a solution that appears optimal in the dual formulation but does not fully satisfy the physical and operational requirements of the original problem. This means that even after many iterations, the algorithm may stop at a solution that is reasonable in the sense that it reflects the expected economic or operational behaviour of the system but is not entirely feasible in terms of adherence to constraints. As a result, the output should be interpreted as an approximate solution one that reflects the cost structure and pricing logic of the relaxed problem, but may not be completely feasible in the strict sense. While this does not invalidate the results, it should be kept in mind when interpreting dispatch schedules or marginal prices: they are indicative of system trends and costs under relaxed feasibility, rather than exact results. For the purpose of this thesis this limitation is acceptable, the intention is to look at system-wide behaviour and for that purpose these results are still valuable, it is therefore decided to continue working with the current model and implement the theory which will be described in the following paragraph.

3.2. Model Implementation

3.2.1. Exact Projection and DC Power Flow

In this paragraph we are concerned with sub-question 2: *How can a flow-based modeling approach be developed to analyze the effects of bidding zone reconfiguration in The Netherlands and Germany on system-wide interactions with respect to market efficiency, congestion and distributional effects?*

To investigate the effects of bidding zone reconfiguration in a realistic and system-wide manner, it is essential to do so according to a method which allows us to make statements about what could potentially happen in the real world. Where the original ATC model is certainly helpful and fit for making statements regarding day-ahead electricity prices it is not fit to reflect real world electricity flows, emerging interactions, and interdependencies between zones. The ATC model by design neglects the physical interdependencies of the power grid ignoring how power flows are distributed across the entire network whereas FBMC is able to account for these aspects. This is especially critical when analyzing the implications of splitting or redefining zones, as such changes alter flow patterns and the frequency and distribution of congestion. FBMC allows us to observe these interactions explicitly.

Therefore, in order to be able to make statements about results, the results must be grounded in the methodology which adheres to reality, this is FBMC. Thus, to obtain meaningful insights into system-wide interactions, flow-patterns and interdependencies FBMC must be implemented within the existing model.

Furthermore, a way of implementing FBMC which remains robust while implementing potential bidding zone reconfigurations is required, the model must still be valid even when zonal configurations change. One way to implement FBMC would be to model the process as is in reality, as similarly laid out by Schönheit et al. (2021). This approach, however, makes use of various assumptions such as those for Generation Shift Keys (GSKs) and Remaining Available Margins (RAMs), which would become invalid once the zonal configuration is modified (as all assumptions would be based on a different zonal configuration). Instead, the Exact Projection method is adopted, which provides a mathematical definition of what FBMC constitutes e.g. it ensures that all feasible zonal positions map back to physically feasible nodal flows.

Rather than relying on approximate representations of network constraints, Exact Projection projects the feasible set of nodal injections onto the space of zonal net positions so that all feasible net positions ($p \vee$ NEX) lie in a feasible set (P). In other words: *"This set includes all zonal net positions for which there exists at least one vector of generator output levels that is feasible under the full network model"* (Aravena et al., 2021, p.1245). The full set of feasible net positions is described by the following equations (Aravena et al., 2021):

$$\sum_{n \in mn(z)} Q_g v_g - \text{NEX}_z = \sum_{n \in mn(z)} Q_n \quad \forall z \in Z \tag{3.15}$$

$$\sum_{p \in mP(n)} Q_g v_g - \sum_{j \in J(n,\bullet)} Fl + \sum_{j \in J(\bullet,n)} Fl = Q_n \quad \forall n \in N \tag{3.16}$$

$$Fl_{\min,l} \leq Fl_{l,t} = \sum_{z} PTDF_{l,n} \cdot NEX_{n,t} \leq Fl_{\max,l} \quad \forall l \in L, \forall t \in T^1 \tag{3.17}$$

In the abovementioned equations, equation (3.15) represents the zonal power balance as the sum of dispatchable generation Q_g weighted by the binary variable for unit commitment v_g minus the net position of zone z, which must equal the sum of all demand Q_n in z. Equation (3.16) represents the nodal power balance, respectively, generation of a node minus outgoing flows and plus incoming flows equals demand in node n. While Aravena et al. (2021) define flows using voltage angle differences, the formulation by Schönheit et al. (2021) is adopted, which expresses line flows directly in terms of Power Transfer Distribution Factors (PTDF) and zonal net positions.

[1] In Aravena et al. (2021), line flows are instead defined using voltage angle differences: $Fl = \beta_l(\theta_{m(j)} - \theta_{n(j)})$.

To apply the proposed theory, a PTDF matrix needs to be constructed, representative for the electricity grid we are modelling, we will do so by utilizing DC Power Flow. The construction of the electricity grid will be highlighted in chapter 4 and the actual PTDF matrix construction can be found in Appendix B. The assumptions and implications of using DC Power Flow can similarly be found in Appendix B.

3.2.2. Flow-Based Market Coupling Model Workflow

The to be implemented theory introduced in section 3.2.1 is implemented in our model using the iterative feedback based mechanism the model initially employed already. Per iteration the entire time horizon is solved and prices are updated. In section 3.1.2 the iterative mechanism has been previously laid out. In this paragraph we'll go step by step through the changes made to the initial model to describe the implemented theory. We will do so by looking at four aspects of the implemented changes: the flow calculation, the surcharge determination, the price updating and how it all fits together. All steps are supported by corresponding flowcharts. Referring back to section 3.1.2, the changes have been implemented inbetween and in step 3 "initial zonal imbalance", step 4 "ATC-based flow computation" and step 6 "price update".

To aid the understanding of what the model does, here is a short description of what iterative updating does intuitively:

At each iteration the model feeds back a signal, an incentive, for the next iteration, the signal here being the price. If a zone causes congestion because there is too much generation, the price is reduced because in this case we want to discourage generation in that zone. If a zone is imbalanced, its price is adjusted either upwards or downwards depending on whether there is too little or too much generation. If there is overproduction we adjust prices downwards and if there is underproduction we adjust prices upwards. This loop will go on until after a certain point the price difference (as opposed to the previous iteration) in the next iteration is sufficiently small that the model is considered converged.

The algorithm may also stop because the maximum number of iterations is reached. At that point supply matches demand and there is no more congestion on lines, or what can also be the case, the algorithm has found a solution which cannot be improved anymore. This means that there is still congestion in the system or that there is still imbalance in the system, the model is unable to improve the solution in the next iteration (or the maximum has been reached). As described before this also implies that if this is the case the results from the model are not coming from a state in which the solution is completely feasible.

Figure 3.2 corresponds to what is explained in the previous paragraph and shows the iterative loop on a high level. From the UD/ED the production per power plant is obtained which is subsequently used to compute physical flows with. Of this physical flow, the overload (congestion) on the transmission lines is computed after which the overload is translated to a "surcharge" representing which node contributed to the overload to which extent. This surcharge is aggregated to a zonal level surcharge which is used to compute the next iteration's price together with the imbalance pricing as described. In the next iterations this loop is repeated until a set of prices with corresponding net positions is obtained for which there exist no more overload and all imbalance is resolved.

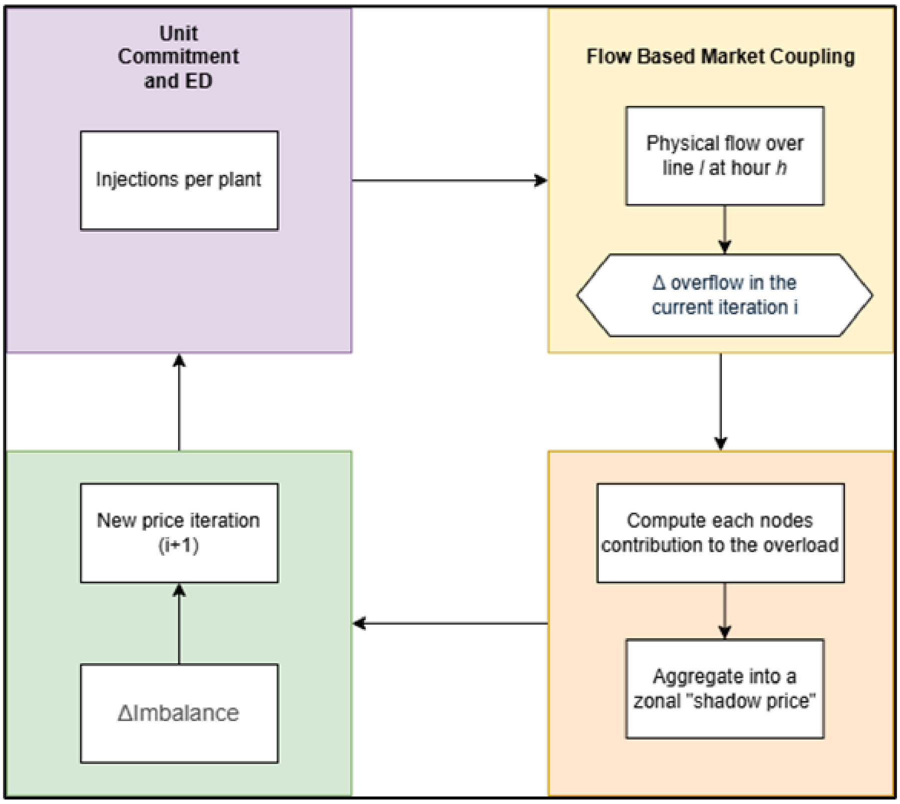


Figure 3.2: High-level Model Workflow, where the yellow square represents the flow and respective overload computation, the orange the surcharge determination and the green the price updating.

The following paragraphs shall in-depth describe what has just been described using the high-level model flow.

3.2.3. Flow calculation

Injection computation

For each hour h, once dispatch values (production per plant) are available from the Unit Commitment and Economic Dispatch (UC+ED) module, the model calculates physical power flows across the network using the following steps:

The dispatch per plant is used to compute nodal injections at each node. This is done by summing the generation from all units located at the node and subtracting the (distributed) load L_n^h.

$$NP_n^h = \sum_{g \in G(n)} Q_g^h - L_n^h$$

Flow computation via nodal PTDF-matrix

Nodal injections are mapped to physical line flows using the PTDF-matrix with the previously described relationship:

$$F_l^h = \sum_n PTDF_{l,n} \cdot NP_n^h$$

This step applies the DC power flow approximation, which linearly relates injections to flows.

Filtering Interzonal Lines

Only interzonal lines (i.e., where ZoneFrom ≠ ZoneTo) are kept for congestion evaluation. This isolates the interzonal part of the network relevant for zonal coupling. Intrazonal lines will be evaluated once interzonal congestion is resolved (see 3.2.4.).

Flow Aggregation and Commercial Flows

Flows across lines are aggregated per pair of zones to define **commercial flows** between zones. These represent how much net transfer occurs between bidding zones and will be used when computing the zonal imbalance as was described in step 5 of Section 3.1.2.

Thermal Limit Check

For each interzonal line, the physical flow F_l^h is compared to its thermal capacity. Lines where:

$$\left|F_l^h\right| > F_{l,\text{thermal limit}}$$

are identified as congested and filtered for surcharge evaluation in the next steps.

Import / Export Capping

Throughout the iterations, flows are computed based on a system where supply is not equal to demand. This entails that in each iteration there may be a portion of flow “created” or “removed”, usually the imbalance mismatch is sufficiently low in every iteration that such instances do not occur. However, in some cases this causes excessive amounts of electricity to be created or removed from the system. It is therefore decided to enforce the maximum available import / export capacity per zone pair. E.g. in a given iteration, the zone cannot have more electricity subtracted from its initial imbalance (from the UC/ED) than its maximum export capacity and vice versa for import capacity. Note that this does not alter the physical flow and overload computations, which remain based on the full physical flows in the model. The purpose of the cap is to stabilize the model, without distorting the underlying physics or the overload penalty mechanism. It thus only affects how much flow is counted as import / export flow when computing a zone’s net position.

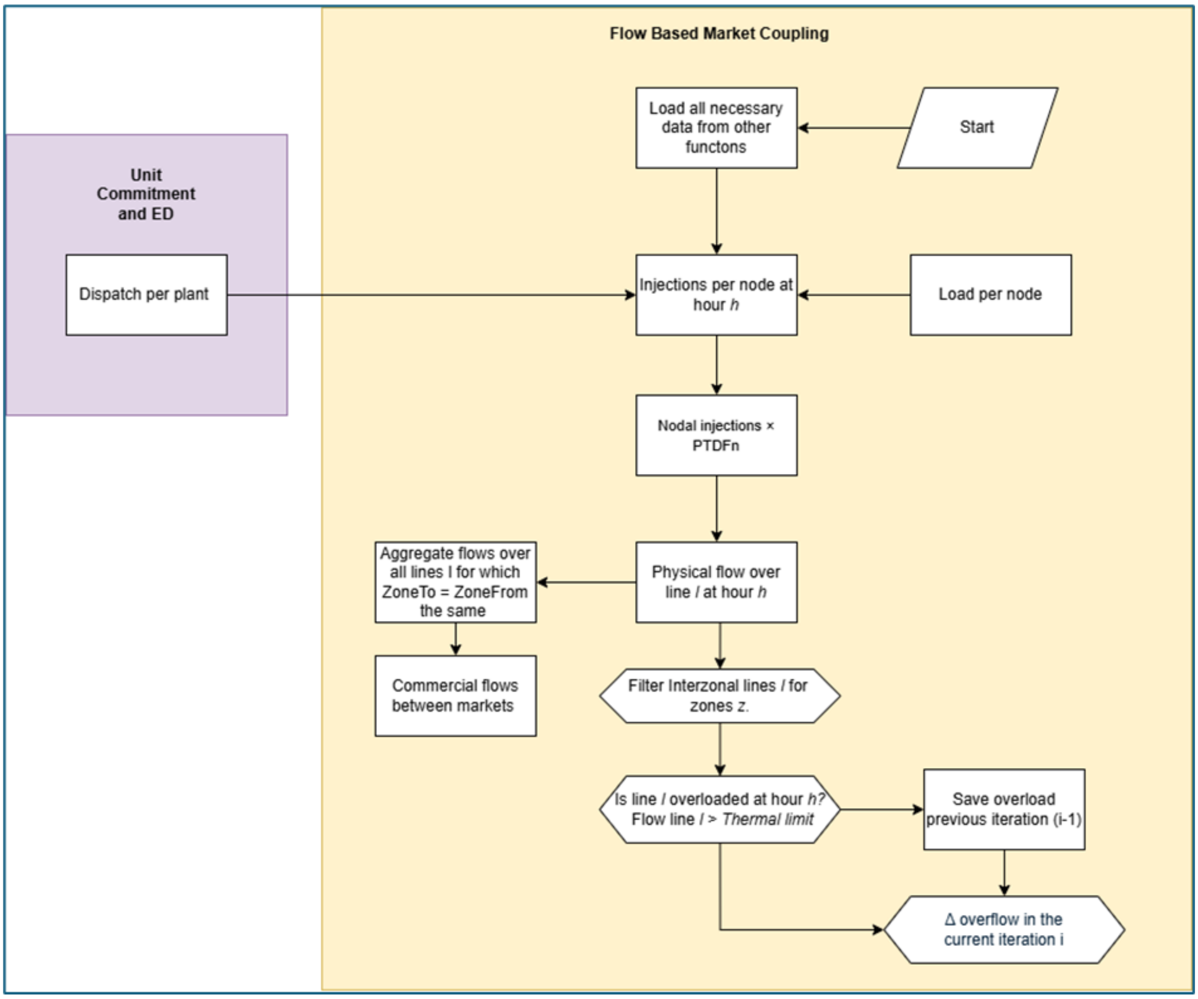


Figure 3.3: Flow Computation Flowchart, the purple block represents the UC/ED whereas the yellow block represents the physical flow computation and overload checking.

3.2.4. Surcharge determination

From the previous step we make a distinction between congested interzonal lines and non-congested interzonal lines. If a zone is connected to the congested interzonal lines it goes through a different set of decisions than if a zone has no congested interzonal lines. We'll first go through the flow of a congested interzonal line. An important note is that all overflow on lines is evaluated relative to the overflow on that line in the previous iteration.

If an interzonal line connected to a zone is overloaded:
The model extracts the relevant portion of the PTDF matrix, focusing on the interzonal lines and the nodes in the affected zone (per zone). For each overloaded line ℓ, the model calculates how much each node contributes to the overload. This Node Score reflects the share of each node's impact on the congested line:

$$\text{NodeScore}_n = \sum_l \text{PTDF}_{l,n} \cdot \text{Overload}_l$$

Compute Zone-Level Surcharge

Each node's score is scaled by a fixed overload cost factor κ, subsequently all node penalties are aggregated into a zone-level surcharge using a capacity-weighted average of all nodes j in zone z:

$$\text{ZoneSurcharge}_z = \sum_{n \in z} \left(\kappa \cdot \text{NodeScore}_n \cdot \frac{\text{Capacity}_n}{\sum_{j \in z} \text{Capacity}_j} \right)$$

The choice of the value for κ is important as it determines "how fast" you want the model to get rid of the overload on the lines. If κ is set too high the prices in the model might start oscillating, if it is set too low, the impact of the zonal surcharge will be too low to force the congestion out of the solution.

If there is no congestion on the interzonal lines connected to a zone:
The model first filters all intrazonal lines per zone z, and goes through the same check where:

$$\left| F_l^h \right| > F_{l,\text{thermal limit}}$$

If there exists no congestion on the intrazonal lines within a zone either, the zonal net position is accepted and deemed feasible.

If intrazonal overload exists:
The model checks whether feasible internal redispatch (within the zone, without changing the zonal NEX) can resolve the congestion. It does so by attempting to greedily redispatch within the zone. What this means in practice is that: The algorithm evaluates all possible pairs of nodes: one to reduce (or "drop") its injection and another to increase (or "inject") by an equal amount (because the zonal *NEX* must stay the same). At each iteration, a fixed quantity of power is transferred between a node pair. For each such drop-inject combination, the model simulates the resulting power flows and evaluates the reduction in total overload across all intrazonal lines.

Each move is assigned a score based on the best-scoring adjustment, the one that most reduces overload is selected and applied. This process is repeated iteratively and stops when there exists no more overload, there does not exist a combination which reduces overload anymore, or the maximum number of iterations is reached. If the algorithm successfully finds a feasible set of redispatch, one that resolved the congestion within a zone, the zonal net position is deemed feasible and no surcharge is applied.

If the algorithm does not find a feasible redispatch solution the surcharge is calculated using the same approach as in the interzonal case, but restricted to intrazonal lines and nodes only. The result is a zone-level surcharge that is added to the market clearing price of the affected zone in the next iteration.

An important note here is that we do not recompute the physical flows with the new nodal injections. Since we assume that since the zonal *NEX* does not change the interzonal flows do not change either. In the next iteration, of course, the flows may change due to the zonal surcharge applied.

The entire process is visualized in Figure 3.4.

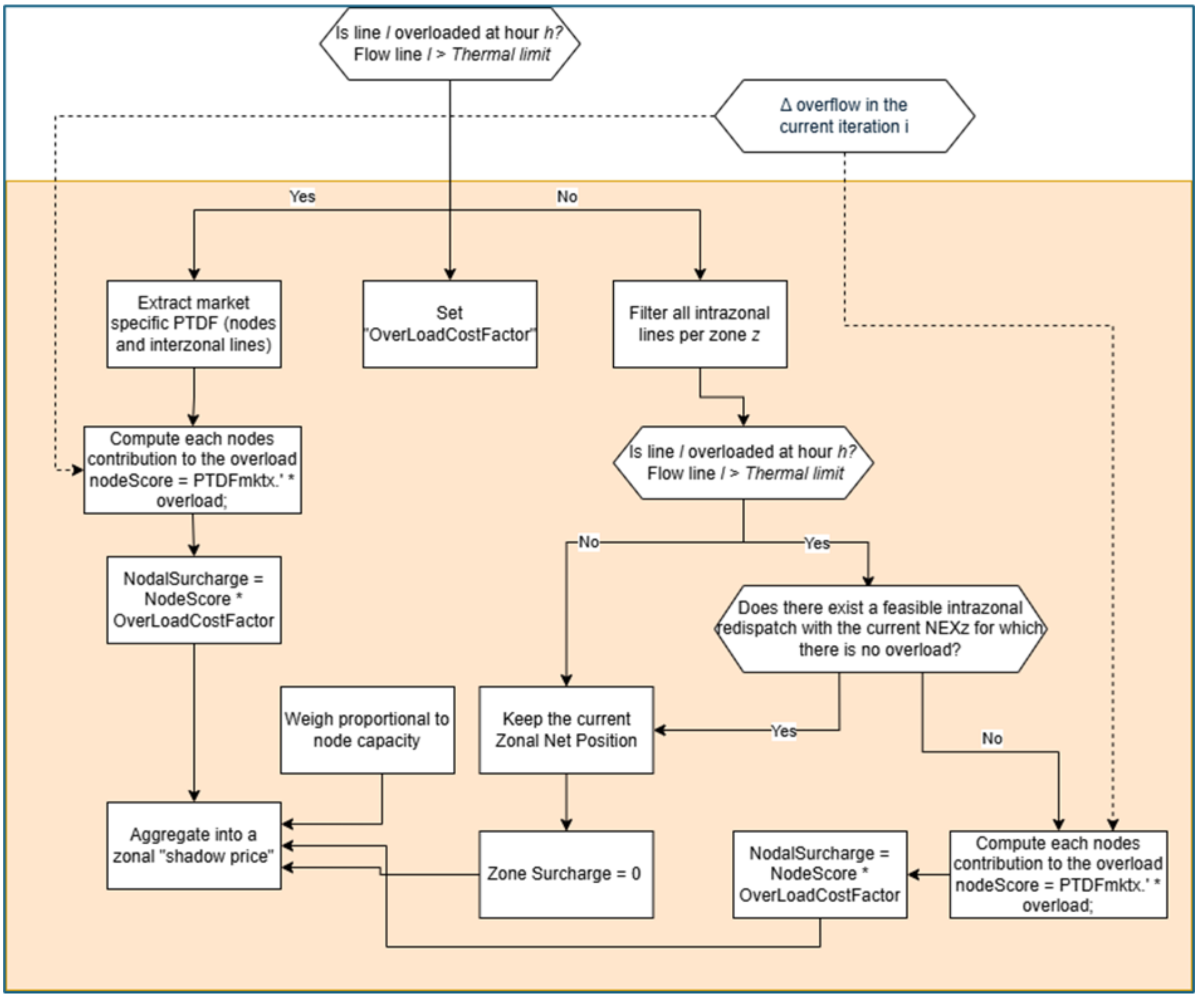


Figure 3.4: Surcharge determination flow, the overloaded lines enter the decision making flow from the previously shown yellow block.

3.2.5. Price updating

The price updating feedback mechanism is what ultimately drives the model towards a state in which the zonal imbalance is resolved and there exists no more congestion on the lines in the model. At each iteration, for every zone and hour, the market price is updated based on two key drivers:

- Zonal imbalance (difference between supply and demand),
- Congestion-related penalties (surcharges due to unresolved overloads).

In order to complete this step the following inputs are used: the imbalance at the current iteration, the imbalance at the previous iteration, the price at the previous iteration, the zonal surcharge and the Beta (β), a model parameter representing how sensitive price is to imbalance.

Compute Change in Imbalance

$$\Delta \text{Imbalance}_z^h = \text{Imbalance}_z^h(i) - \text{Imbalance}_z^h(i-1)$$

This captures how the zone's imbalance evolved from the previous iteration to the current one.

Compute Price Change from Imbalance

$$\Delta \text{Price}_{z,\text{imbalance}}^h = \beta \cdot \Delta \text{Imbalance}_z^h$$

This reflects how much the price should respond to the imbalance trend.

Combine with Congestion Penalty The total price adjustment includes both the imbalance effect and the congestion penalty (if any):

$$\text{Price}_z^h(i) = \text{Price}_z^h(i-1) + \Delta \text{Price}_{z,\text{imbalance}}^h + \text{ZoneSurcharge}_z^h$$

The flow is again visualized in the following Figure 3.5, price updating flow:

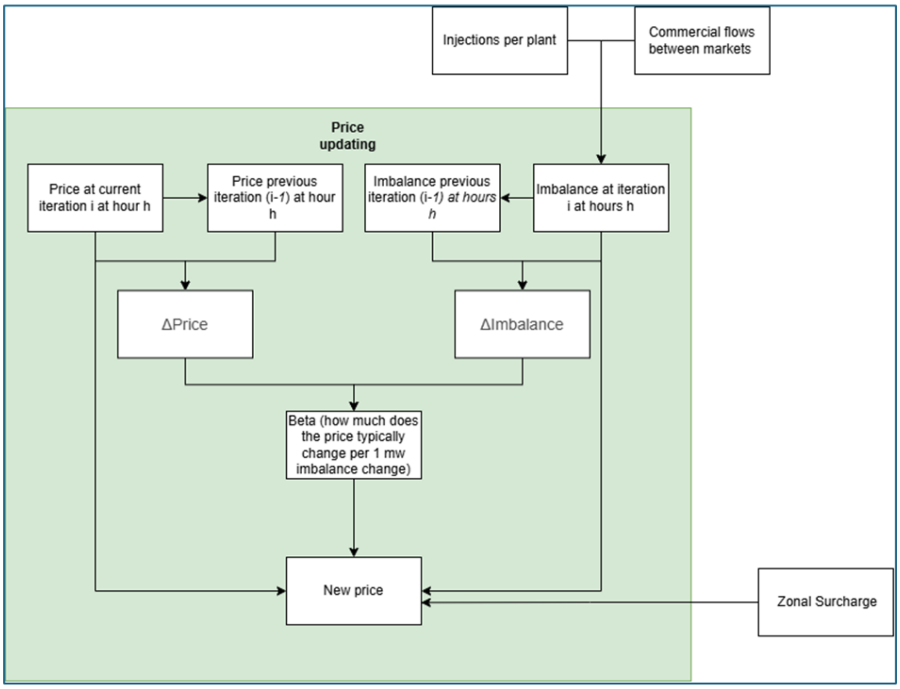


Figure 3.5: Price Updating Flow, the zonal surcharge from the surcharge determination is used for the price updating.

3.2.6. How it all fits together

In Figure 3.6, *Exact Projection model implementation*, it is shown how the different functions fit together and amount to the Exact Projection theory together. The polytope of all nodal injections and with that, the set of feasible net positions (Aravena et al., 2021) is what the ultimate solution reflects. The solution in which there exists no more line overloads or imbalance in the system.

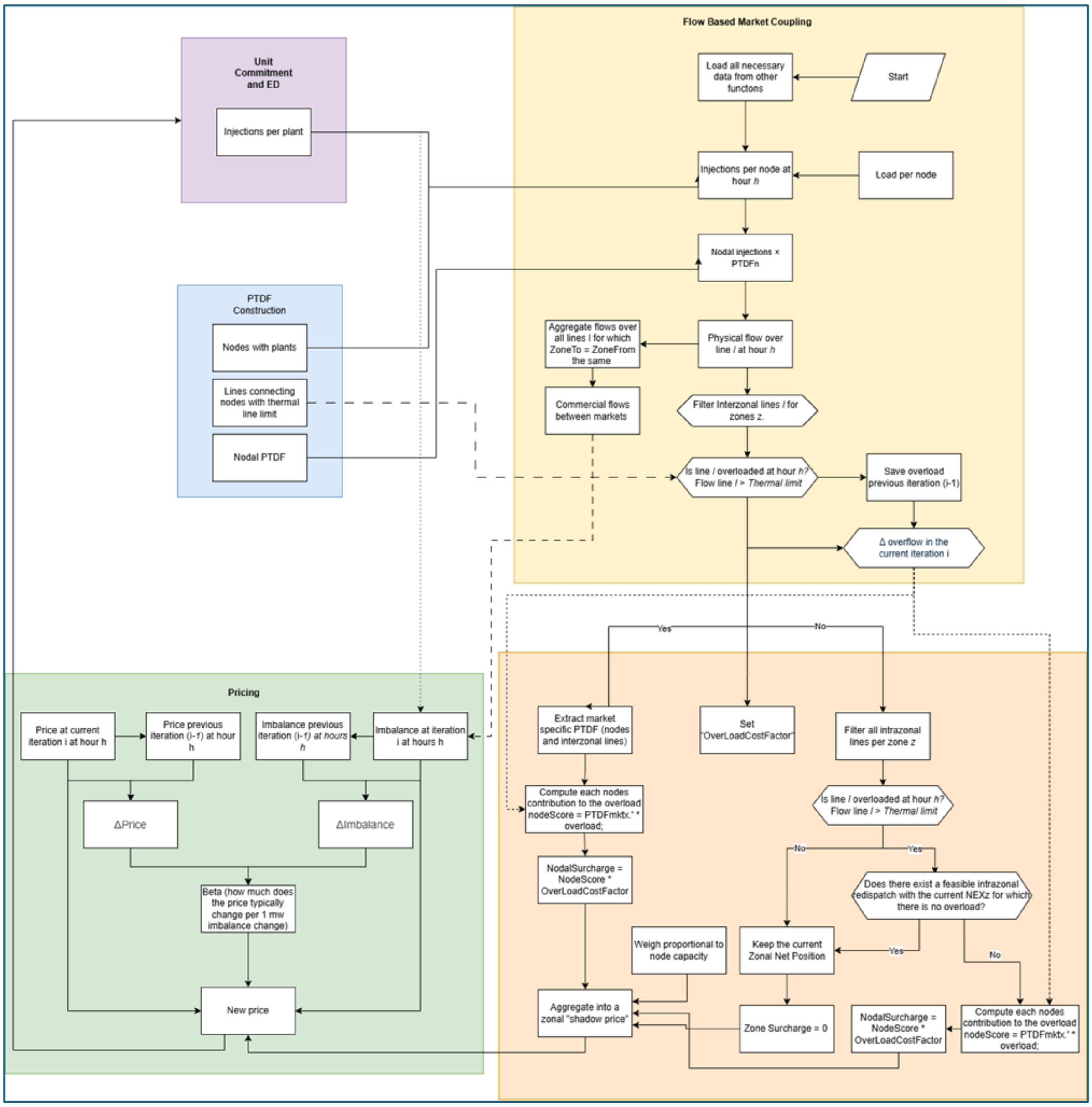


Figure 3.6: Exact Projection Model Implementation, the blocks shown over the course of the model explanation are all shown together in order to show how they work together.

3.3. Performance Indicators

In the conducted literature review in chapter 2, there have been several performance assessment metrics identified to evaluate the effects and impact of bidding zone configurations. In order to answer sub-questions 3: "*How does the reconfiguration of the Dutch and German bidding zones affect system-wide market efficiency and congestion?*" and 4 "*How does the reconfiguration of the Dutch and German bidding zones affect system-wide zonal market outcomes and system interactions*?" the model outcomes need to be operationalized in such a way they can be interpreted and assessed. In the literature review we identified the following assessment metrics:

1. Congestion Metrics

To assess congestion, we will evaluate:

- Overload percentage on interzonal transmission lines, indicating the frequency and severity of congestion. [%]
- Line utilization, measuring how intensively transmission lines are used relative to their capacity. [%]
- Changes in redispatch, redispatch volumes will likely be very high due to the zonal aggregation (see chapter 4). Therefore it'll be insignificant to investigate volumes or costs associated with redispatch. What we can assess is the alignment of supply and demand before and after splitting bidding zones by observing the change in required redispatch. [% change]

2. Distributional Effects

Reconfiguring bidding zones can have distributional consequences across market participants and zones. To assess these effects, we will analyze:

- Net positions of bidding zones (both existing and newly defined), this will reveal changes in commercial exchange patterns and cross-border interactions. [GWh]
- Price effects across zones, focusing on how prices evolve under different configurations. Together with net positions, this provides insight into the allocation of economic benefits and disadvantages, identifying which zones may profit from lower prices or vice versa. [€/MWh]

3. Market Efficiency

Finally, the impact of bidding zone reconfiguration on overall market efficiency will be assessed through:

- Price volatility, to analyze price stability and uncertainty [Δ€]
- Frequency of extreme price events [% of hours], an extreme price event is not standardized in existing literature. Therefore in this thesis the minimum price threshold is used as the negative price. The minimum price threshold as described previously has been set to -100 €/MWh. With respect to extremely high price events, the shift in the 95th percentile threshold is observed. The threshold will be reported on (€/MWh) and will likely shift due to the effects of bidding zone reconfigurations.

Where applicable, results will be compared with the findings and indicators used in BZR 2 to benchmark our results and to investigate differences and similarities which can lead to new insights.

4 Data and Case Study

This chapter outlines the reconstruction of the European electricity grid and shall describe the construction process. Since the accuracy and reliability of the model depend on how the physical grid and generation data are represented, special attention is paid to data sourcing, processing, and spatial reconstruction.

The chapter begins by substantiating the choices made with respect to scoping in the case study, including the selected time period and geographical coverage. Then the focus is on the reconstruction of the transmission network using the JAO (2024) Static Grid Model. Section 4.2, explains how transmission line parameters, such as electrical reactance/susceptance and thermal capacities, were derived and integrated into the model. Next, in Section 4.3, the focus is on generation data, initially sourced from KYOS, which includes key technical specifications of power plants. Since generation is modelled at the bidding zone level, geolocation tools are used, including a combination of APIs, to spatially group power plants into representative nodes. Finally, in Section 4.4, it is described how the spatial reconstruction of transmission lines and generation units was achieved, resulting in a geography based nodal structure that integrates both transmission and generation data. This reconstructed grid forms the foundation for the case study analysis. A critical reflection is conducted on the constructed grid, and several measures are introduced to enhance its resemblance to reality.

4.1. Scope

The time scope for this study follows a two-step approach. First, a back-testing phase is conducted using historical data to validate the model. By comparing model-generated outcomes with actual market results from a known period, the accuracy and reliability of the modelling approach can be assessed under real-world conditions. This validation step ensures that the model is capable of replicating market dynamics before being used for forward-looking analysis. Following this, for this study it's been chosen to simulate 2 periods, one being April 1st 2023 until April 30th and the other being January 3rd until January 30th. These periods have been chosen as simulating a period in spring and in winter may yield different results due to differing renewable energy availability.

The geographical scope of this study is limited to the FBMC region, as defined by the Joint Allocation Office (JAO). Countries outside this region, are excluded to avoid the additional complexity of modelling interactions between differing capacity allocation mechanisms ATC/FBMC. Restricting the scope to the FBMC region also ensures access to consistent, high-quality data from sources such as the JAO's Publication Tool, which provides key parameters and results necessary for accurate modelling and validation.

4.2. Transmission Lines

The transmission line data used in this model is extracted from the JAO (2024) Static Grid Model (2024-10 version), which provides a simplified yet representative abstraction of the European power system for market coupling purposes. The dataset includes a subset of all high voltage internal lines and cross-border lines in the European electricity grid. Each line entry includes its electrical reactance, from which susceptance values are derived (1/R) and used in the determination of the PTDF matrix using the DC power flow approximation. The lines are each assigned to a corresponding substation as "Hub From" and "Hub To". This substation is usually a place name in which the substation is located. The geographical location of each substation exactly is not given in the dataset.

In order to obtain the geographical location, the OpenStreetMap API, Nominatim (Nominatim, 2024), has been used in a custom Python script which yielded the latitude and longitude of each substation. The search queries used in the Nominatim API are the following:

- "electricity substation, CountryX"
- "electrical transmission station, CountryX"
- "grid substation, CountryX"
- "power station, CountryX"
- "CountryX"

The obtained geographical locations have afterwards been checked manually and have been corrected where needed. The manual check has been done by checking if the latitude / longitude approximately corresponds with the substation location.

The subsets of interzonal and intrazonal lines are delivered by each TSO individually. This causes interzonal lines to be included double, e.g., TenneT NL and ELIA both count the lines connecting their borders as their own interzonal lines. The lines being reported double have been omitted from the dataset. Lines mapped to countries outside of the geographical scope have been omitted as well. In total this amounted to 87 omitted interzonal lines.

Consequently, the thermal capacities of these interzonal lines can be derived from the line properties, voltage and current, in the dataset and then be used to define the transmission limits used in the model. The thermal capacity of transmission lines can be calculated by the following formula:

$$P_{\text{max}} = \sqrt{3} \cdot V \cdot I$$

As the Static Grid Model dataset reports either fixed values or dynamic line ratings over different periods for the current (I), the values have to be averaged. The different periods represent the dynamic line rating difference over different "ambient conditions" (JAO, 2024). Since each TSO reports different criteria based on varying ambient conditions (JAO, 2024), the provided current values are used as follows: if a fixed value is reported, it is applied directly in the calculation; if multiple line ratings are reported, their average is computed.

4.3. Power Plant Data

Power plant data has initially been provided by KYOS, the data included power plant names, capacities, commodities, ramping limits, maintenance periods, etcetera. Since bidding zones in the model are modelled as aggregated zones, generating units have been appended to a bidding zone rather than a physical / geographical location. In order to obtain the geographical location the Nominatim API has again been used, substituting 'substation' for 'power plant' in the previously shown queries. Since the Nominatim search queries relied mainly on powerplant names, this yielded insufficient results. Therefore a combination with a Chat GPT API as backup was used with the following prompt:

"Give the latitude and longitude of the powerplant named '{name}' in Europe, Google search the plant name and return only latitude and longitude."

The returned output was again checked manually and corrected where necessary. The geolocated powerplant dataset ultimately includes 1132 powerplants. The generation mix for each bidding zone is shown in figure 4.1, as well as the total installed generation capacity per zone. The generation mix can in later stages provide insight when bidding zones are assessed. The generation mix is known to be an indicator for prices in a bidding zone, the abundance of nuclear energy for instance often results in low electricity prices whereas a lot of gas fueled power plants often cause higher electricity prices (Stringer et al., 2023b). Figure 4.1 shows the generation mix of the modelled countries, keep in mind that renewables are excluded in this figure which may give an inaccurate representation.

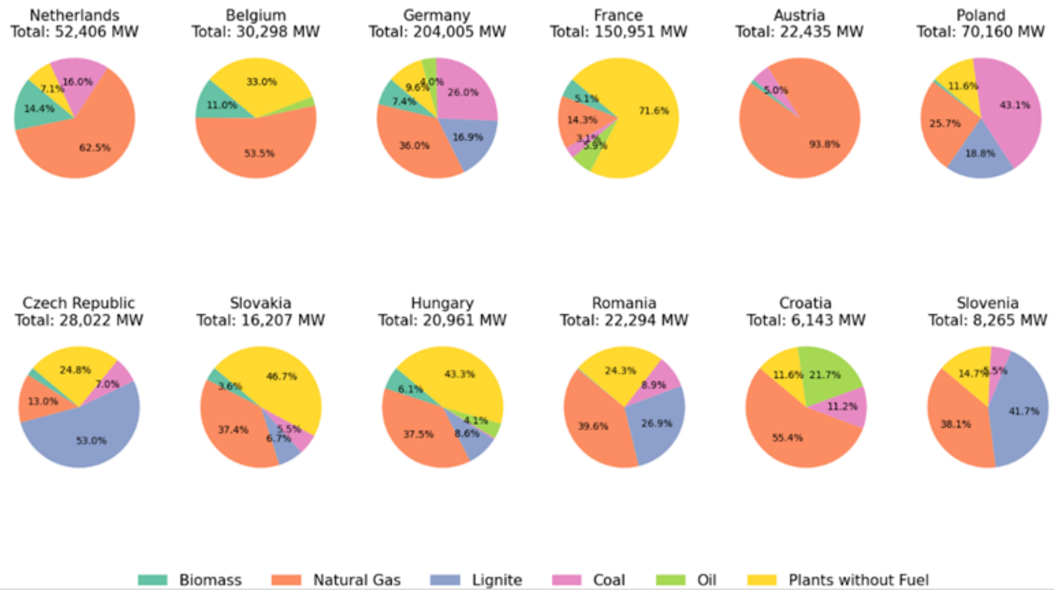


Figure 4.1: Generation Mix Per Bidding Zone (Plants w/ fuel are Nuclear)

To validate the generation mix used in the modelling, the plant data from KYOS, per market, is compared with International Energy Agency (IEA) data from 2023 (*Countries & Regions - IEA*, 2023). Wind and solar were excluded from both datasets to ensure a fair comparison, as these technologies are not represented in our modelled mix. The comparison focused on five countries: Netherlands, Belgium, Germany, France, and Poland. For each, we calculated the Mean Absolute Error (MAE) which can be found in Table 4.1, a visual comparison for these countries is shown in Appendix C. The MAE shows that the modelled generation mix is sufficiently close to reality to be representative.

Country	Mean Absolute Error on Generation Mix
Netherlands	0.026
Belgium	0.090
Germany	0.090
France	0.046
Poland	0.122

Table 4.1: MAE per country on generation mix

There is one especially important assumption made with respect to the modelled minimum price. By default, the minimum price is set at -100 €/MWh. Economically, this is similar to the effect of a subsidy which allows generators to run even when the market value of electricity is negative (up to -100 €/MWh).

This threshold has a direct impact on the results: the lower the minimum price, the lower the average market prices observed in the simulation, as generators are allowed to bid 'further' into the negative range. However, this effect only becomes active when market prices actually reach the imposed minimum. Moreover, due to cross-border market coupling, the price floor can also influence neighbouring zones. If the capped zone reaches its minimum price while continuing to export electricity, it can consequently lower prices in adjacent markets.

Since the chosen threshold may significantly impact results the effect of changing this parameter has been investigated in Appendix D "Model Parametrization & Results". The conclusion on this parametrization can be found in Section 4.7.

4.4. Data Sourcing and Quality

Using 2023 as both the base year and model year ensures that all input assumptions, such as electricity demand, generation availability, and grid configurations, are grounded in observed rather than forecasted or outdated data. This enhances the reliability and realism of the simulation.

The renewable generation and demand profiles are based directly on 2023 data. For renewable generation, this means the hour-by-hour pattern observed in 2023 is used without adjustment, capturing realistic variability due to weather and seasonal effects. Similarly, electricity demand is modeled using the actual hourly demand profile from 2023.

While this approach ensures consistency and data accuracy, it also implies that the simulation reflects system conditions as they occurred in 2023. Any potential differences in weather, demand growth, or installed capacity that might arise in future years are therefore not captured. However, this trade-off is acceptable for the purposes of this study, which focuses on comparing bidding zone configurations under consistent system conditions.

4.5. Spatial Reconstruction

To group individual power plants in nodes, based on their geographical distribution, K-means clustering was employed. This algorithm partitions observations into a pre-specified number of clusters by minimizing the variance within each cluster (IBM, n.d.). This means, that plants within close spatial proximity to one another are grouped together. In this context, plant latitude and longitude coordinates were used as input features, and the resulting cluster centroids served as newly defined spatial nodes representing aggregated generation points. A choice was made here to cluster the plants into 200 nodes. This choice has been based on a compromise between the spatial granularity observed in the proposed bidding zone splits by ACER (*figure 2.5)* and the amount of modelled power plants (1132). To validate the granularity, a comparison is made with that used in PyPSA-Eur, which typically employs a clustering between 37 and 300 nodes, where 37 is considered aggregated and 500 is considered detailed (PyPSA-Eur, n.d.). Given that only the CORE region is modeled, the chosen granularity is considered sufficiently detailed.

Since ultimately the aim is to investigate The Netherlands and Germany specifically, the granularity within these countries and Belgium has been increased. The choice to increase the granularity in

Belgium as well is due to the effect that changes in Belgium will have on the electricity systems in Germany and The Netherlands, and the detail we want to observe these changes with. Plants in these countries have been assigned increased weight as to obtain approximately twice the spatial granularity compared to that in other countries.

Subsequently, the geographical coordinates of substations from the Static Grid Model were matched to the nearest reconstructed nodes derived from the clustering step. This matching process is based on the geographical location of the lines extracted from the Static Grid Model and the newly defined nodes. Through this methodology, a simplified but representative version of the European electricity grid was obtained. The resulting network combines the original transmission infrastructure from the SGM with generation data provided by KYOS. The result is shown in Figure 4.2. If you observe the figure closely there are a few 'self-loops', lines for which the beginning and end point has been matched to the same node. Within the model these lines are excluded.

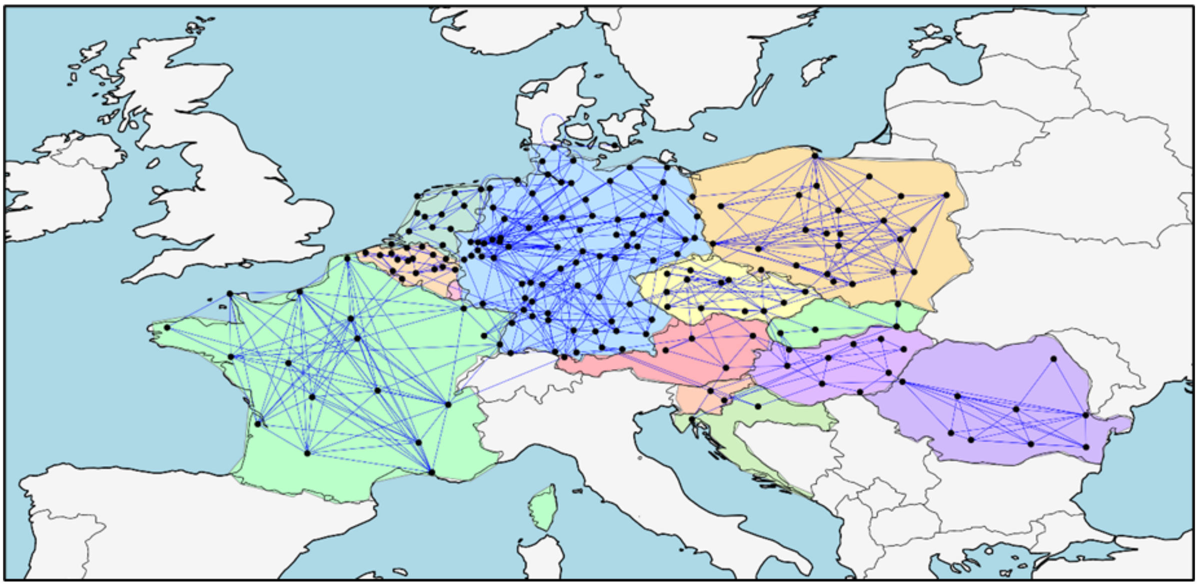


Figure 4.2: Spatial Reconstruction Transmission Grid (2024-10), the spatial proximity in the Netherlands, Belgium and Germany has been increased as opposed to the rest of the Core region.

4.6. Splitting of Demand over Nodes

In order to spatially distribute electricity demand within each country in the model, demand is allocated to individual nodes based on the regional distribution of Gross Domestic Product (GDP) and population at the NUTS 2 level. The underlying assumption is that these 2 combined serve as a reasonable indicator for electricity consumption (Robinius et al., 2017).

However, to account for situations where GDP may not accurately reflect actual consumption, such as regions dominated by a single high-revenue enterprise with relatively low electricity usage, each allocation is manually reviewed. This validation step ensures that demand is not disproportionately assigned to nodes where economic output does not correspond to a proportional share of energy usage. It has been decided that, although some regions are highly industrialized such as Germany South (Balasubramanian, 2025), the assumption holds for the current analysis and that the demand allocation can thus be used for the investigation at hand. If a NUTS Region has multiple nodes appended, the demand is split equally.

4.7. Conclusion on Model Parametrization

In this section the effect of modelling choices which were made and the extent to which the model is sensitive to the input data is investigated. This is necessary both to improve the model's adherence to reality and to understand the sensitivity of outcomes to different model configurations. Here, "model configuration" does not refer to changes in the underlying model behavior or logic, but to adjustments to the assumptions and input parameters described. The three key assumptions we analyze are regarding the line susceptances, thermal line limits, and the minimum price threshold. In the model testing phase it has been noticed that the model is sensitive to changes in these inputs. In Appendix D the parametrization testing can be found. This conclusion comments only on what is further applicable and important in the following chapter on the model results.

The thermal line limits obtained from the Static Grid Model, when divided by 2 as to reflect original values more accurately, showed to be for every bidding zone pair a bit under – or above the values in reality (Appendix D). It was therefore decided to adopt the capacities as reported by ENTSO-E which can be found in figure 4.3. It is important to note that the choice of thermal line limits does not directly affect the physical flow computations themselves, which are always based on full physical flows derived from the PTDF matrix. However, the thermal limits do serve as the activation threshold for the congestion pricing mechanism in the model: they determine when a line is considered "congested" and when the corresponding overload penalties become active. The interconnection capacity is enforced as the maximum export or import which can be added or subtracted to the net position of a zone (this is similarly described in Chapter 3).

As previously described, line susceptances in the model are derived from the input data of the Static Grid Model. This means that if the input data is inaccurate, the resulting flows can be unrealistic. For example, on the Belgium–Germany border, the static grid model contains a line with a susceptance of 20 Siemens a value 1000% higher than many other lines in the SGM (This will be elaborated upon in Chapter 5). There are about 60 other instances of this, mostly intrazonal lines in Germany and the Netherlands. After extensive testing, it has been decided to cap the line susceptances at 2 Siemens. A sufficiently high threshold to preserve the fact that certain lines originally attracted high flows, while avoiding unrealistic magnitudes.

With respect to the assumed minimum price threshold the model has been tested with four different thresholds [-100€/MWh, -75€/MWh, -50€/MWh, -25€/MWh]. The most important observed effect is that zones with a high amount of installed renewable capacity benefit in terms of reduced prices when the minimum price threshold is lowered. Germany for instance, shows roughly a 14€/MWh price increase in price (averaged over all the hours in April 2025, still in the testing phase, hence the date) when the minimum price threshold is increased from -100€/MWh to -25€/MWh. For the Netherlands this difference is roughly 8€/MWh. Overall it should be noted that the model is sensitive to this input. The inital decision to model a -100€/MWh minimum price threshold is based on extensive testing by KYOS which has shown that this threshold yields the most accurate prices when compared to real-data. The decision to stick with a threshold of -100€/MWh is made, but it should be noted that this may significantly affect price results in zones with a lot of renewable capacity and possibly neighbouring zones.

All parametrization and sensitivity analysis described can be found in Appendix D. There is one validation exercise which has been carried out but has not been reported on in Appendix D.

It was attempted to validate modelled flows in order to compare modelled electricity flows to real world data. However, this exercise was ultimately excluded from the reported results due to significant methodological and structural mismatches. The PTDFs from the Joint Allocation Office (the real PTDF values) are provided at the nodal level, based on a grid topology and substation mapping that do not align with the nodal structure used in our model. To apply these PTDFs meaningfully within a zonal market coupling framework like ours, they would first need to be aggregated into zonal PTDFs, this is not possible without information on the associated assumptions such as GSK's. Furthermore, the JAO PTDFs are hourly and contingency-inclusive, incorporating (N-1) security criteria. Our model, by contrast, does not include contingencies or hourly PTDF variation, it assumes a single representative PTDF matrix constructed through the DC power flow approximation (Appendix B). For these reasons, the exercise yielded no meaningful results and is therefore not included in the main analysis.

Country From	Country To	Reference grid ENTSO-E (MW)
Netherlands	Germany	5000
Czech	Germany	4200
Austria	Germany	5400
Belgium	France	4300
Netherlands	Belgium	3400
Germany	France	3300
Belgium	Germany	1000
Poland	Germany	3000
Hungary	Croatia	1700
Slovakia	Hungary	2600
Austria	Czech	900
Slovenia	Croatia	2000
Poland	Czech	1400
Czech	Slovakia	1800
Poland	Slovakia	1980
Hungary	Slovenia	1200
Austria	Slovenia	950
Austria	Hungary	800
Hungary	Romania	1100

Figure 4.3: Thermal line limits ENTSO-E, the ENTSO-E reference grid interconnection capacities are shown.

4.8. Bidding Zone Reconfiguration Scenarios

In this paragraph the bidding zone configurations which we're going to investigate in the following chapter will briefly be described. The respective assumptions regarding the splitting of demand, the splitting of renewable generation availability and the cross-border capacity between the newly formed zones will be discussed.

Bidding zone configuration 1: Netherlands-North and Netherlands-South

The first bidding zone configuration which will be investigated will be the splitting of the Netherlands into a Northern and a Southern zone following the bidding zone configuration as proposed by ACER and shown in Figure 4.4.

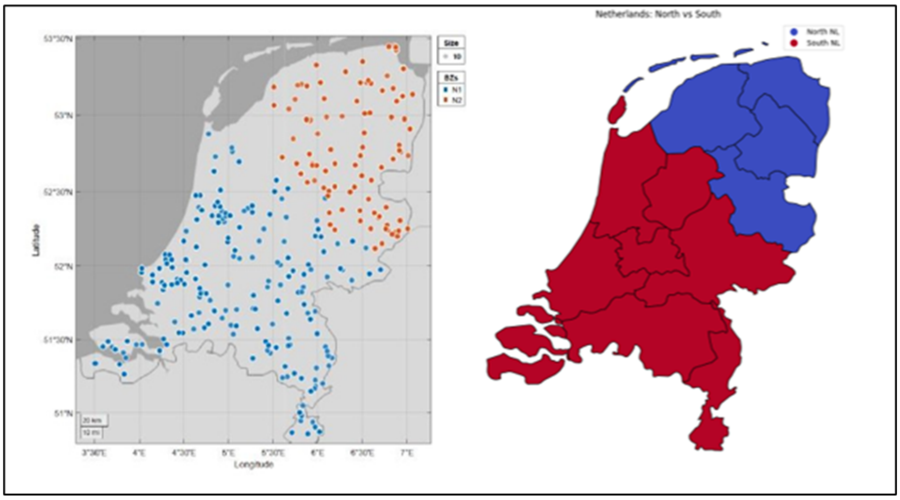


Figure 4.4: Proposed Dutch bidding zone configuration by ACER, sourced from ACER (2022)

The proposed split roughly corresponds with a split between the Northern Dutch provinces: Drenthe, Flevoland, Friesland and Groningen and the rest of the Netherlands. In the scenario for bidding zone configuration 1: Netherlands-North and Netherlands-South, these provinces are appointed to the North of the Netherlands and all of the other Dutch provinces to Netherlands-South. Table 4.2 shows the assumptions made in order to split the Dutch data in a Northern and a Southern region. As shown in the table, most of the Dutch demand is located in the South, especially in the Randstad, where most companies and households are located (CBS-Statline, 2024). Most offshore wind capacity is located at the Zuid- and Noord-Holland coasts and most onshore capacity is installed in Flevoland, all appointed to the Netherlands-South region.

Region →	**Netherlands North**	**Netherlands South**	**Source**
Load	17%	83%	(Eurostat, 2024)
Solar capacity	27%	73%	(CBS, 2023)
Onshore wind capacity	27%	73%	(CBS Statline, 2024)
Offshore wind capacity	13%	87%	(Rijksoverheid, 2024)

Table 4.2: Data assumptions bidding zone configuration 1, Netherlands North-South.

The interconnection capacity between the Netherlands North and – South is assumed to be 5 GW, this is based on the error margin previously identified on the modelled interconnection capacities and on what the initial value from the SGM was.

Bidding zone configuration 2: Germany-North and Germany-South

The second bidding zone configuration which'll be investigated will be the split of Germany in a Northern and a Southern region. The split as proposed by ACER (Figure 4.5) has not been delineated by province borders. To facilitate the data collection process it is decided to split Germany into whole provinces rather than drawing an artificial line through a country. Therefore going forward the Northern provinces for Germany will be "Bremen, Hamburg, Schleswig-Holstein, Mecklenburg-Vorpommern, Berlin, Brandenburg, Sachsen-Anhalt, Sachsen, Niedersachsen, Thüringen", the remaining provinces have been assigned to the South of Germany.

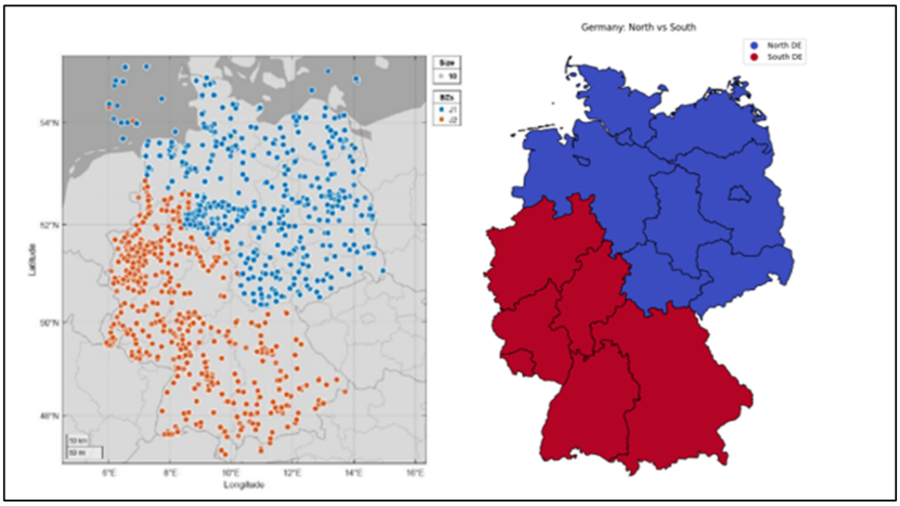


Figure 4.5: Proposed German bidding zone configurations by ACER, sourced from ACER (2022), the bidding zone split has been based on the Northern/Southern provinces aligning with the split as proposed by ACER.

As seen in Table 4.3 most of the German demand is located in the highly industrialized Southern region. Renewable capacity on the other hand is mostly located in Germany North, especially offshore wind capacity as Germany-South does not have any coastline.

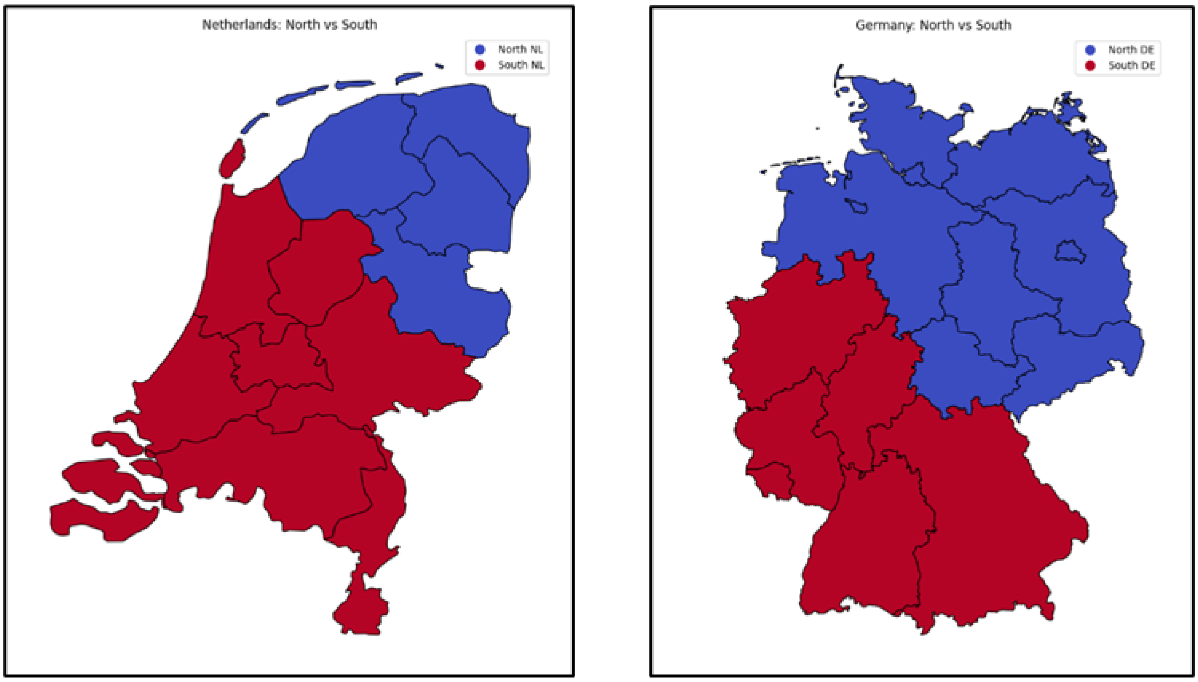
Region →	Germany North	Germany South	Source
Load	22%	78%	(Eurostat, 2024)
Solar capacity	35%	65%	(Agentur Für Erneuerbare Energien, 2024)
Onshore wind capacity	66%	34%	(Agentur Für Erneuerbare Energien, 2024)
Offshore wind capacity	100%	0%	(Agentur Für Erneuerbare Energien, 2024)

Table 4.3: Data assumptions bidding zone configuration 2, Germany North-South.

The modelled interconnection capacity in Germany is 10 GW based on the same assumption as for the Dutch reconfiguration.

Bidding zone configuration 3: Germany- and Netherlands North-South

The third bidding zone configuration which is going to be investigated will be a combination of bidding zone configuration 1 and 2. Both The Netherlands and Germany will be split in North and South. This is done in order to investigate the potential newly formed interactions between the bidding zones.



(a) Dutch bidding zone configuration

(b) German bidding zone configuration

Figure 4.6: Split Scenario 3: Germany and The Netherlands North-South reconfiguration

This of course also implies that the assumptions from bidding zone configurations 1 and 2 still hold.

5
Results

This chapter will focus on presenting the results we obtain from the model including FBMC. We want to verify whether the model behaves as intended or not and we want to validate that the model produces outputs consistent with real-world market outcomes. When the model is verified and validated we can establish if the model is suitable for assessment on bidding zone reconfiguration. In consequent model runs and for our results we'll use the model as described in the methodology and which will therefore be named the Flow Based Market Coupling model (FBMC-model).

5.1. Model Validation

We first want to verify whether the model's behaviour over iterations is in accordance with how we've described it in chapter 3, the methodology. To do so we'll look at the behaviour and outcomes over the course of the iterations. From chapter 3 follows that we're ultimately looking for a converged model state, which means the model finds a state for which there is no more imbalance and no more overload left in the system.

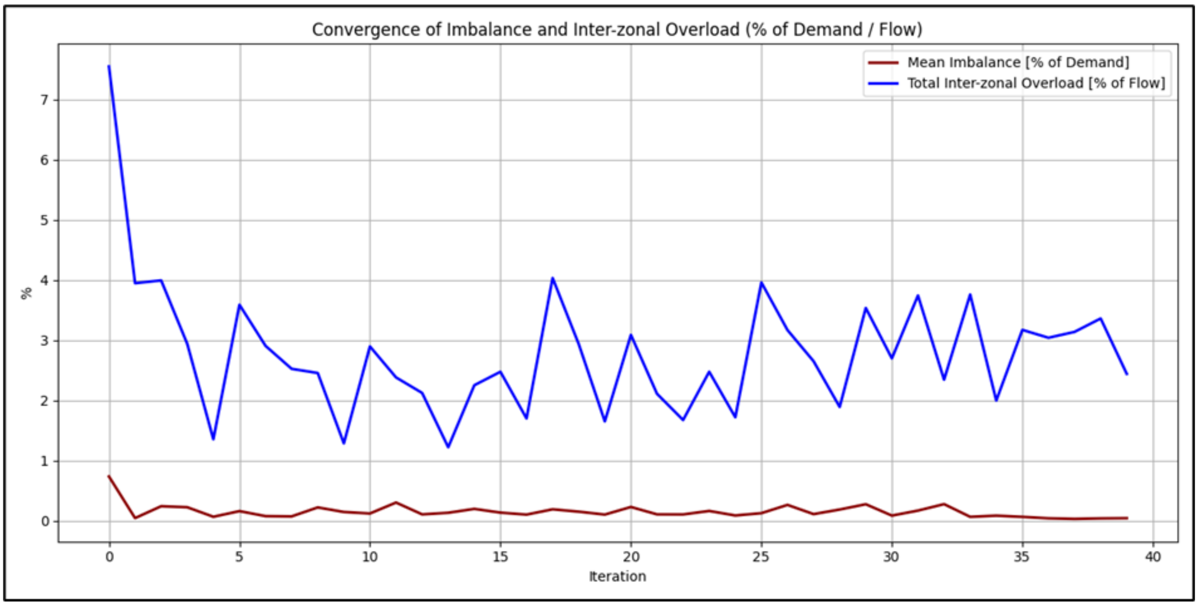


Figure 5.1: Imbalance and Overload over the iterations FBMC model, the blue line indicates the total interzonal overload (averaged over all hours) and the red line indicates the imbalance in the system (averaged over all hours.

Figure 5.1 shows the evolution of the mean system imbalance (expressed as a percentage of total system demand) and the total interzonal overload (expressed as a percentage of total interzonal flow), over model iterations. The results are computed as a mean over both zones and hours per iteration. In this case, both imbalance pricing and zonal surcharges are applied to the system, following the methodology described in Section 3.2.

We observe that the system imbalance converges close to zero, as expected when applying imbalance pricing. At the same time, the interzonal overload is also reduced significantly compared to its initial level of over 7% of total interzonal flow, ultimately stabilizing around 2% after several iterations. However, a small amount of residual interzonal overload remains in the system across iterations. This means the algorithm is unable to find a solution for which both the demand matches supply and for which there is no overload remaining in the system. It does, however, also show that the model behaves as intended and that the model behavior aligns with how we've described it in Section 3.2. An important note is that model outcomes are a compromise between imbalance-based and congestion-based pricing, imbalance and overload may in the solution still exist although very limited.

This might be due to the fact that thermal line limits, interconnection capacities, are too tight for the model to be able to convergence. To show that the model behaves as intended the line constraints are relaxed slightly. Figure 5.2 shows that in this situation the model is able to converge to a solution in which overloads and imbalances are almost 0%.

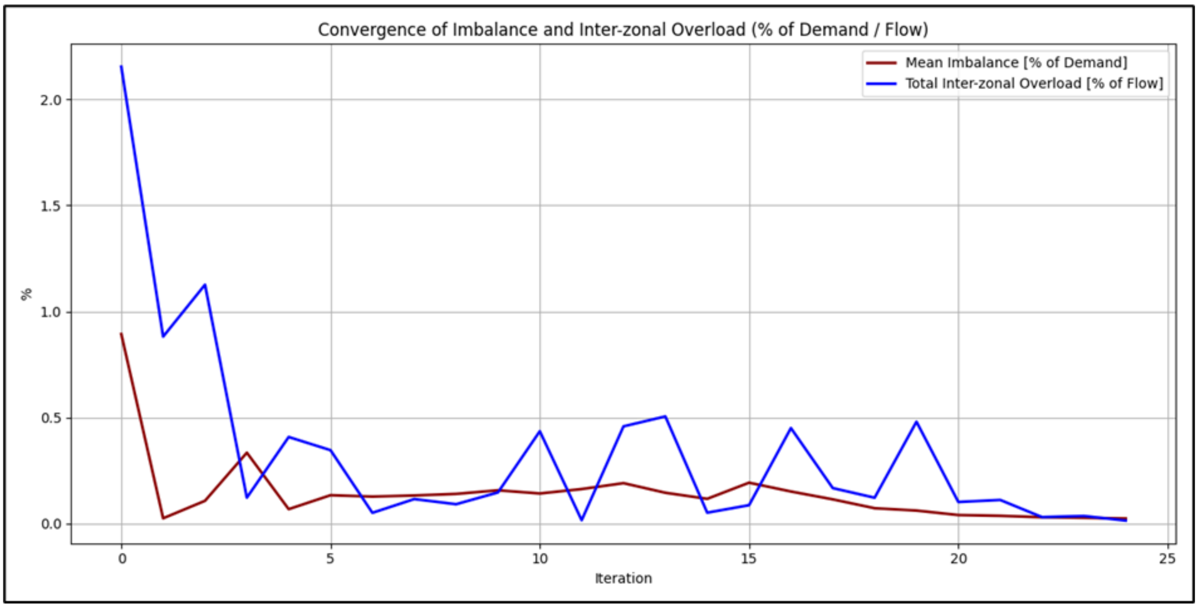


Figure 5.2: Imbalance and Overload over the iterations, Relaxed Interconnection Constraints. The blue line indicates the total interzonal overload (averaged over all hours) and the red line indicates the imbalance in the system (averaged over all hours

In Figure 5.3 the average intrazonal overload in the system is shown before and after redispatching. The figure is intended to show model behaviour not as a validation of results, in the sense that the values in the graph have no meaning, only the direction matters. We see that the model effectively eliminates the intrazonal overload through redispatching plants within respective zones. The values are averaged over zones and hours, per hour and per zone the amount of intrazonal overload may differ. The figure shows that the redispatch mechanism behaves as described in Chapter 3.

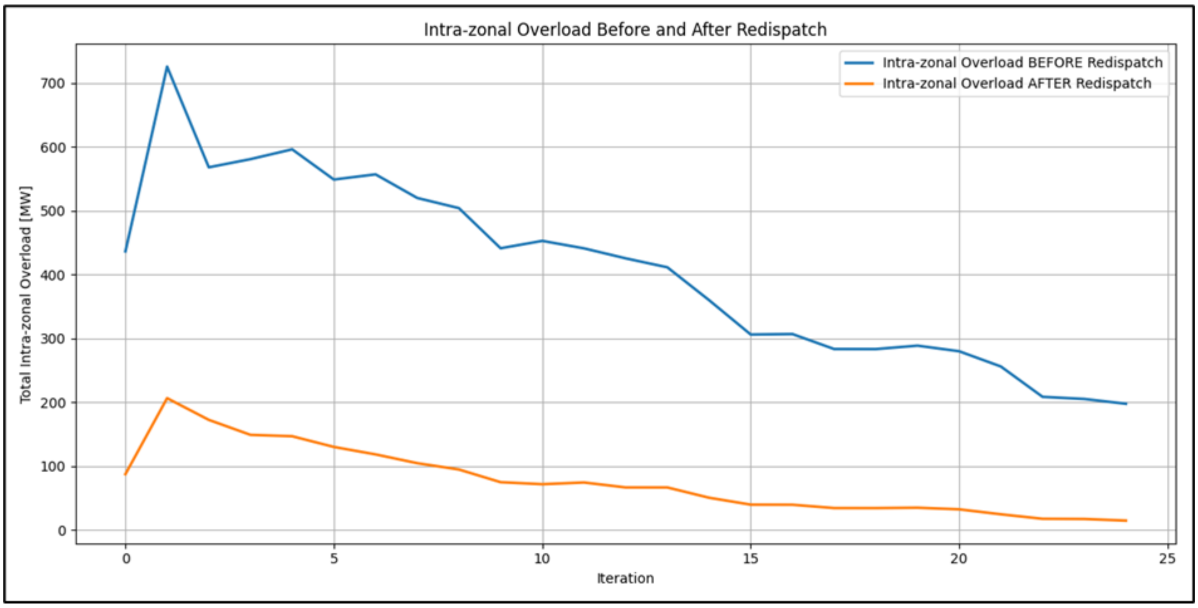


Figure 5.3: Redispatch Effectivity, Intrazonal Overload (MW) over Iterations before and after Redispatching, the blue inidcates the values before redispatching, the orange line after redispatching

5.2. Model Verification

Before the model can be used to draw conclusions about the effects of splitting bidding zones, it is important to first assess how well the model reflects real-world system behaviour. In particular, we need to verify whether the modelled results are consistent with observed data for key indicators such as electricity prices and cross-border flows. This comparison serves as a verification of results to ensure that any conclusions we later draw about zonal splits are based on a model that captures the essential dynamics of the system with sufficient accuracy. In this section, we therefore evaluate how well the model performs in reproducing real-world prices / flows / imbalances across several countries. The period of January 3rd 2023 until January 30th 2023 is investigated. We first evaluate the obtained prices.

5.2.1. Prices

Table 5.1 shows the MAE and RMSE for the hourly electricity prices of 5 countries, observed is that the unchanged model setup which was called “ATC” performs the best when compared to real world price data from EPEX SPOT and the EEX Transparency Platform (Energy-charts, 2025). The FBMC model performs slightly less well in some zones such as NL / DE and BE, this is to be expected since the ATC model is constructed to simulate hourly electricity prices. The original model is calibrated to simulate electricity prices as accurate as possible, making it especially suitable in this regard. The original model assumptions, input data assumptions etc. have all been done so that the model is as accurate as possible, the model has now been changed but these assumptions have not, this must be kept in mind.

Zone	MAE ATC (%)	RMSE ATC (%)	MAE FBMC (%)	RMSE FBMC (%)
NL	28.68	34.55	46.73	55.73
DE	23.96	29.64	37.97	50.23
FR	20.39	25.40	29.60	37.48
BE	20.69	25.75	41.22	52.63
PL	29.14	33.95	18.96	24.42
CZ	20.44	25.66	23.11	29.99

Table 5.1: MAE and RMSE for prices across different countries under ATC and FBMC models.

In order to understand the model behaviour with respect to prices better, the German case is investigated in more detail. The FBMC model seems to underestimate prices as opposed to the ATC model.

An important note regarding this aspect is concerning the previously introduced assumption on a -100 €/MWh minimum price threshold. A parametrization exercise has previously been described, of which a portion of the outcomes is shown in Table 5.2. It clearly shows the effect of changing the minimum price threshold and should be kept in mind when interpreting results. This fact is similarly modelled in the ATC simulation, it is thus not an explanation for price differences between ATC / FBMC simulations.

The most likely cause for the price underestimation, is that Germany profits from other zones through imports which are only reflected in the FBMC model. To validate this hypothesis, the average hourly net position for Germany is computed and is shown to be almost -7.5 GWh in the ATC simulation and -3.1 GWh in the FBMC simulation. This shows that Germany is still a big exporter but less so, making for, on average, lower prices. This is a result of the congestion pricing introduced in FBMC which lowers Germany's zonal price as to cause less congestion in the system through reduced generation.

Table 5.2: Effect of changing the minimum price threshold. All values are in €/MWh. Please keep in mind that this exercise has been carried out in the testing phase of the model and therefore reflects average German prices in April 2025, the table must purely be seen as an indication of model behaviour under different parametrizations.

Country	Threshold	Mean	Std Dev	Min	Max	△Mean
DE	–25	54.37	59.54	–25.00	208.08	–
	–50	48.65	67.24	–50.00	203.98	–5.72
	–75	44.86	73.73	–75.00	205.30	–3.79
	–100	40.27	80.30	–100.00	210.20	–4.59

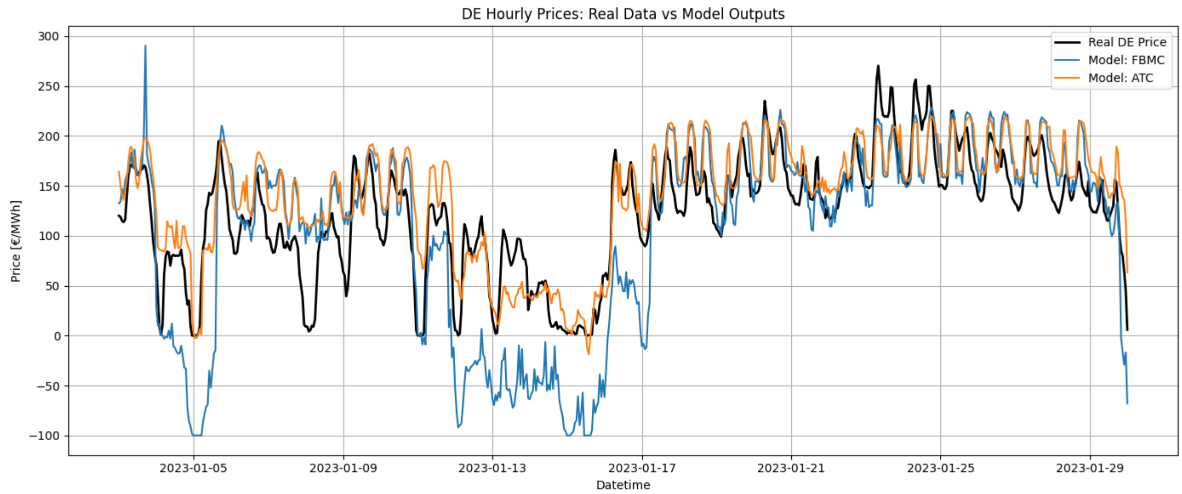


Figure 5.4: Germany Hourly Day Ahead Price, FBMC / ATC / Real Day-Ahead prices, the blue line shows FBMC, the orange line ATC (original model) and the black one real data

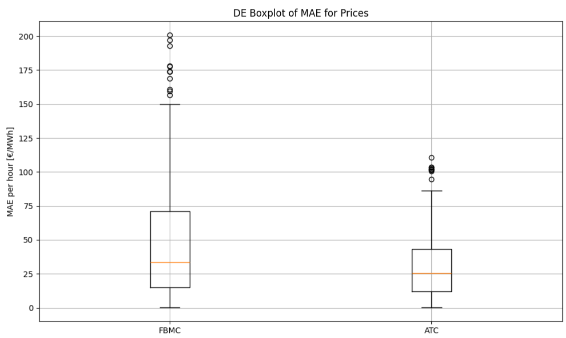


Figure 5.5: Mean Absolute Error associated with the German hourly electricity prices; ATC is on average slightly more accurate

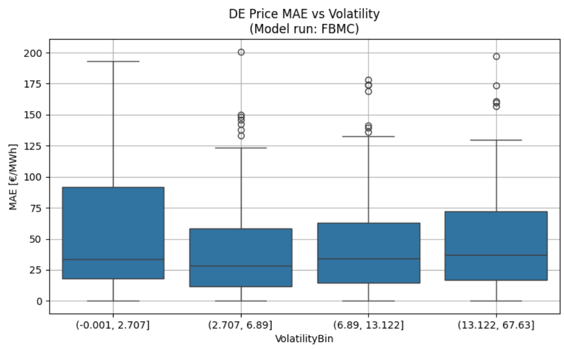


Figure 5.6: MAE per price volatility bin; when price volatility is low, MAE is higher

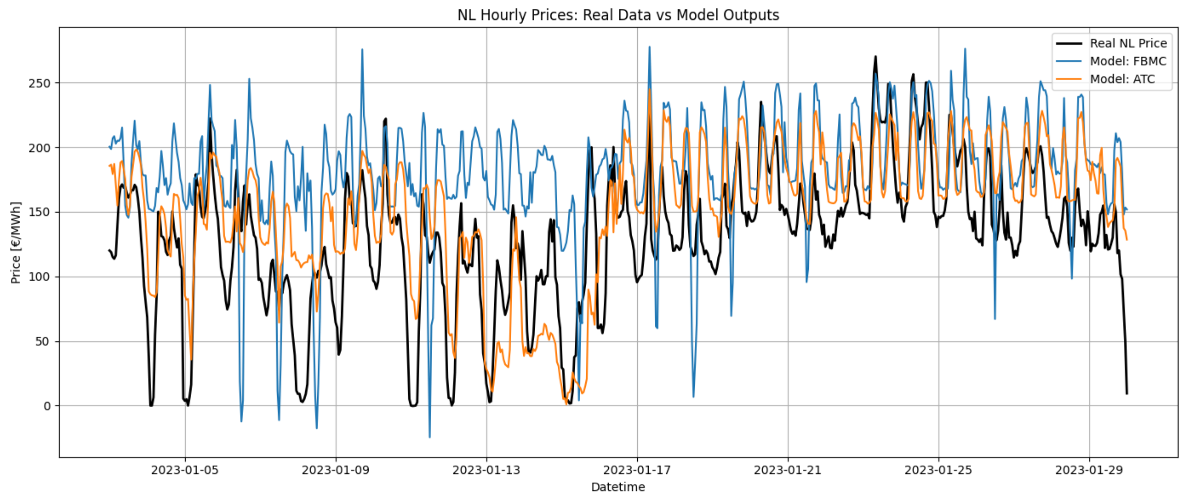


Figure 5.7: Dutch day-ahead electricity price, FBMC / ATC / Real Day-Ahead prices, the blue line shows FBMC, the orange line ATC (original model) and the black one real data

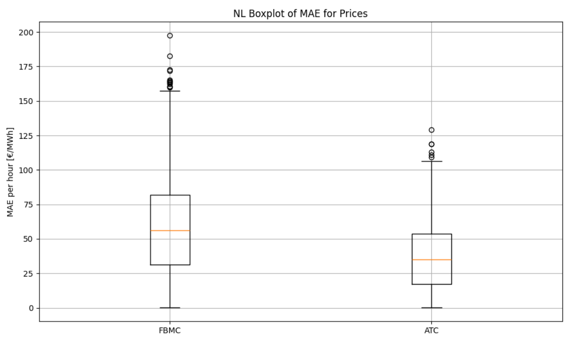


Figure 5.8: Mean Absolute Error associated with the Dutch hourly electricity prices; ATC is on average slightly more accurate

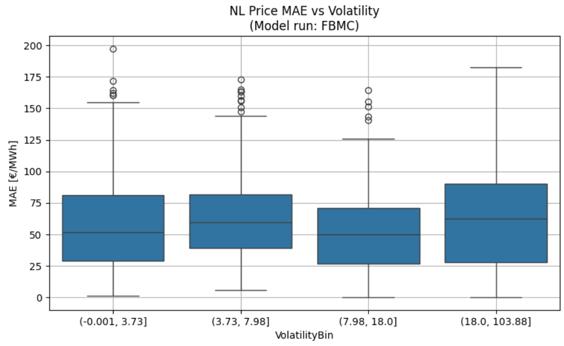


Figure 5.9: MAE per price volatility bin; when price volatility is high, MAE is higher

We aim to understand the conditions under which the model performs well and where it falls short, as this directly impacts the reliability of conclusions regarding zonal splits.

Figures 5.6 and 5.9 compare the MAE to price volatility. These plots show that the model generally performs well under moderate price conditions but tends to exhibit a slightly larger error margin during price spikes and extreme events, particularly when compared to the ATC model.

To illustrate this, Figure 5.10 presents the FBMC model error relative to real prices during 20 identified sharp downward price spikes. The x-axis represents the difference between the FBMC model and the actual price (i.e., FBMC – Real). Most of the distribution is concentrated on the negative side, with errors reaching below -100 €/MWh. This clearly indicates that the FBMC model tends to overreact to downward price events, predicting more severe drops than what materialized in the real market.

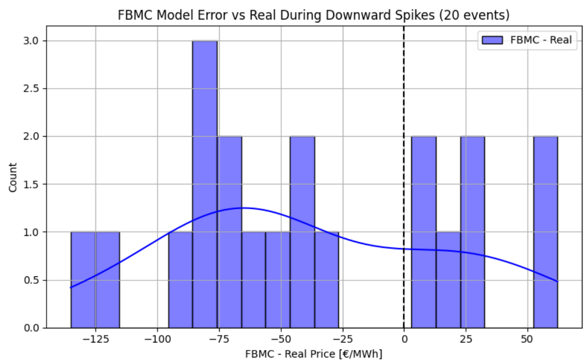


Figure 5.10: FBMC model error during downward spikes, the x-axis should be interpreted as a difference as opposed to real prices, illustrating that when prices drop sharply downward the FBMC model tends to overestimate this dip.

5.2.2. Flows

This section is dedicated to presenting how the model performs with respect to electricity flows. In Table 5.3 we observe that the FBMC model performs better when compared to the scheduled commercial electricity exchanges, as reported by the ENTSO-E Transparency Platform (ENTSO-E, 2025). This is expected, as the FBMC model is designed to ensure physical feasibility of the power flows within the network constraints, whereas the ATC model is primarily calibrated to reproduce prices rather than flows.

Zone → Zone	MAE ATC (%)	RMSE ATC (%)	MAE FBMC (%)	RMSE FBMC (%)
NL–DE	173.33	201.44	99.55	127.31
BE–DE	81.75	94.49	82.49	91.37
NL–BE	108.00	126.08	112.25	151.80
DE–FR	73.64	90.94	93.28	114.10
BE–FR	208.32	232.39	215.05	229.31
DE–AT	70.38	86.97	61.93	73.88
DE–CZ	100.70	124.61	96.01	126.22

Table 5.3: MAE and RMSE of modelled hourly flows (as % of average real absolute flow) across key borders.

In Figure 5.11 the net flow exchange between The Netherlands and Germany is shown. the ATC model shows higher deviations from the actual net flows, both in terms of MAE and RMSE (Figure 5.12 / 5.13). The flow however is very limited, most likely this is due to the Netherlands being fairly balanced throughout the modelled hours or the electricity flowing intrazonally. If the demand and injections in the Dutch nodes are overall balanced, then the need for import or export is less, as generation is already located correctly in order to meet demand; this will be observed in more detail in.

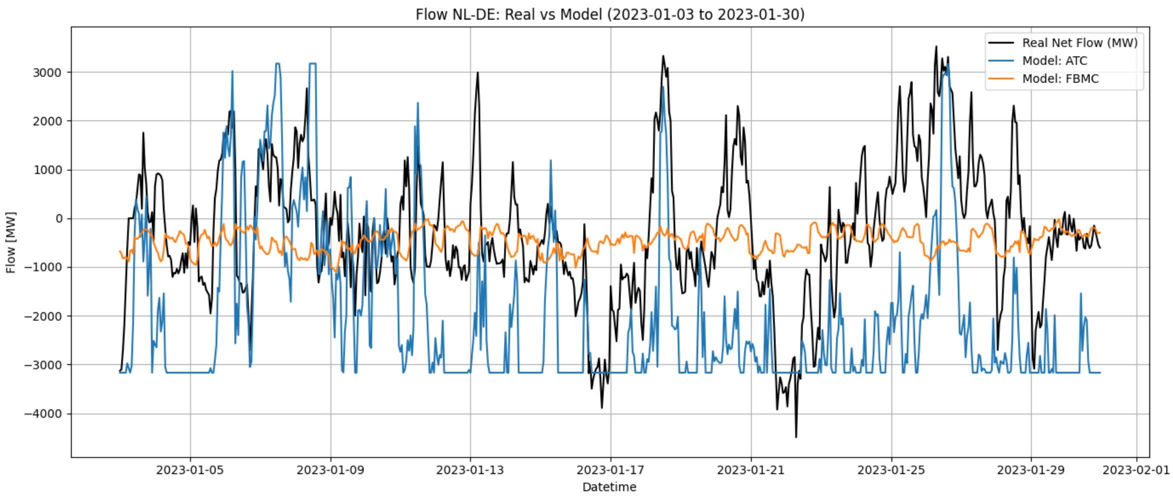


Figure 5.11: Electricity flow between The Netherlands and Germany ATC vs FBMC, the orange line shows the FBMC flow, the blue line the ATC flow, the black line the real flow.

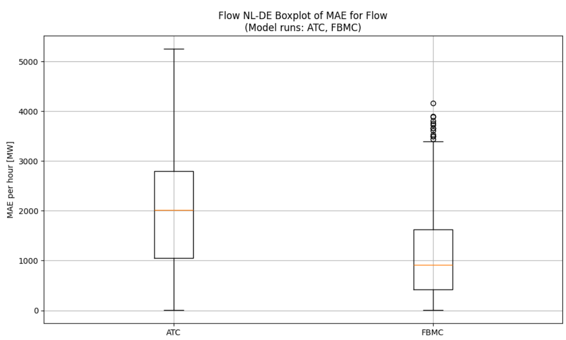


Figure 5.12: MAE for flow NL–DE, it can be observed that FBMC yields significantly lower MAE in this case

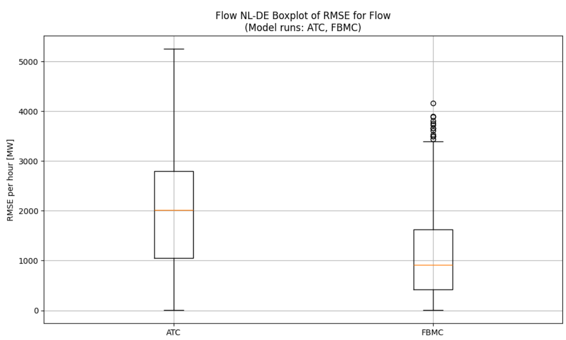
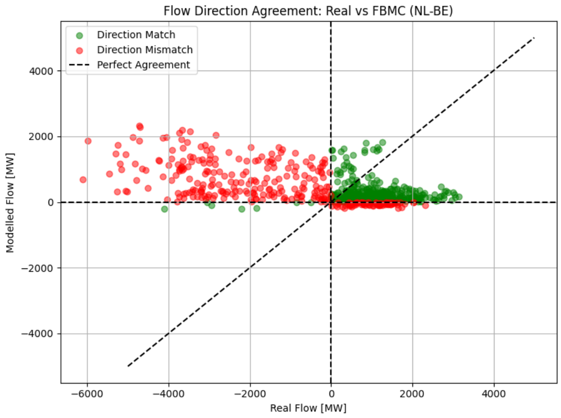
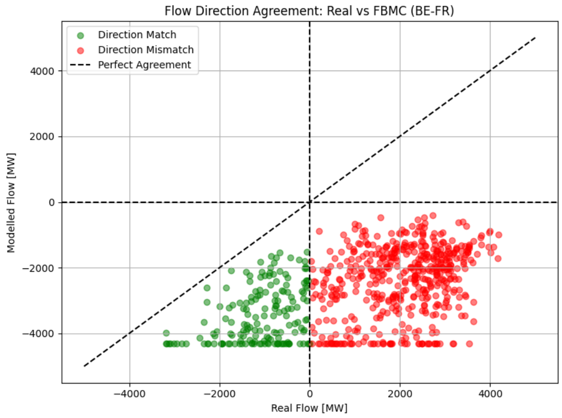


Figure 5.13: RMSE for flow NL–DE, similar results to MAE

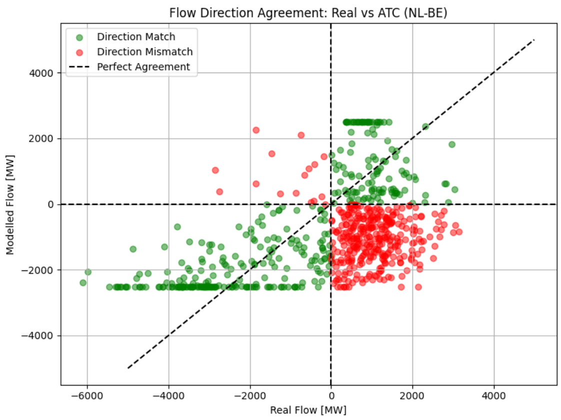
In some cases the model performs slightly worse, as can be observed in table 5.2 this is mostly the case when Belgium is involved. Observed is that the flow direction is often opposite to what is observed in reality, this is plotted in Figure 5.14.



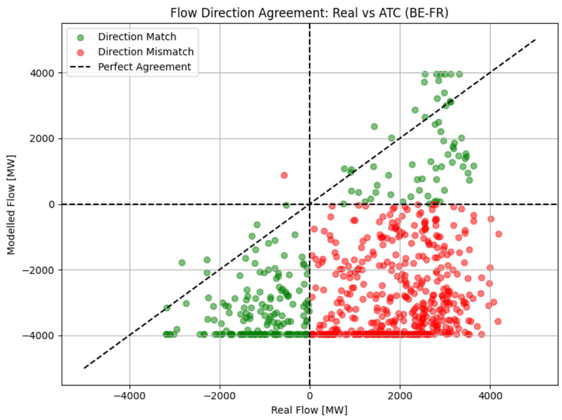
(a) FBMC: NL-BE Flow



(b) FBMC: BE-FR Flow



(c) ATC: NL-BE (Alt)



(d) ATC: NL-BE Flow

Figure 5.14: Comparison of Flow Direction Agreement: FBMC vs ATC (NL-BE and BE-FR). The 2 figures above show the FBMC direction and magnitude and the figures below show the corresponding ATC values.

The main observed difference as opposed to reality is that Belgium, when modelled, is mainly an importing zone whereas in reality in this time frame Belgium has exported as well as imported. A possible explanation for this could be that the modelled demand in Belgium is way higher than in reality. In order to check this, the residual load in Belgium is compared to the actual residual load in January 2023, this is shown in Figure 5.15. The residual load in Belgium itself is modelled accurately and therefore disregarded as a cause.

The model input data in this respect has previously shown to be inconsistent. In this case this is most likely due to the fact that in reality the Belgian - German interconnection model is the ALEGrO interconnector, a High-Voltage Direct Current (HVDC) link between Lixhe (Belgium) and Oberzier (Germany). The input data from the Static Grid Model treats this border as any other border except that this interconnection has higher susceptance than the other interconnections. The model (input data) regards this line similar to every other line as an uncontrollable transmission line whereas in reality the HVDC line can be controlled in terms of how much power flows over the line (Amprion, n.d.). The model still retains its value in the sense that it represents the structural capacity to exchange electricity between Germany and Belgium, the controllability of this line however is lost. This mismatch may result in inaccuracies in flow distribution or unrealistic utilization of the interconnector within the model, particularly in scenarios involving congestion. The earlier introduced measures which limit the effect of the inconsistencies in input data with respect to the susceptance, limit the adverse effect but do not fully resolve them, the effect may still be shown in terms of increased flow inaccuracy which must be taken into regard.

Another possible explanation for the flow mismatch could be loop flows which cause the flows on Belgian borders to seem counterintuitive. We'll similarly look at this in more detail in the split scenario results.

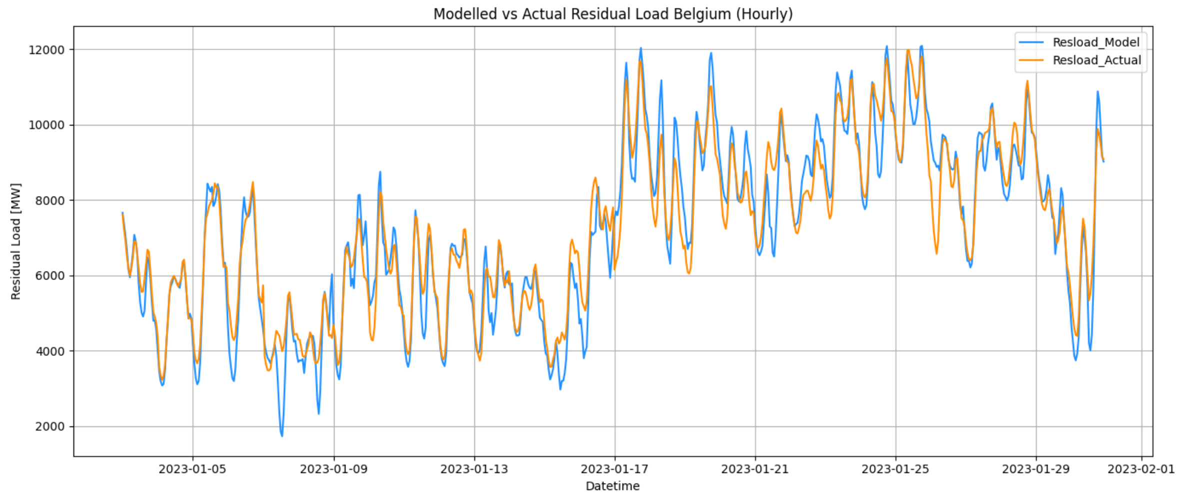


Figure 5.15: Modelled vs. Actual Residual Load in Belgium, January 2023, the residual load is deemed to be modelled accurately.

In other cases, in which the direction of modelled flow aligns with what is observed in reality, the FBMC model tends to capture the real flow behaviour way more accurately. In the case of Germany-Austria for instance, the direction and magnitude of flow is better captured by the FBMC model as opposed to the ATC model. This is illustrated in the scatter plots in figure 5.17 and 5.18 showing both the direction and magnitude match of the ATC and the FBMC model.

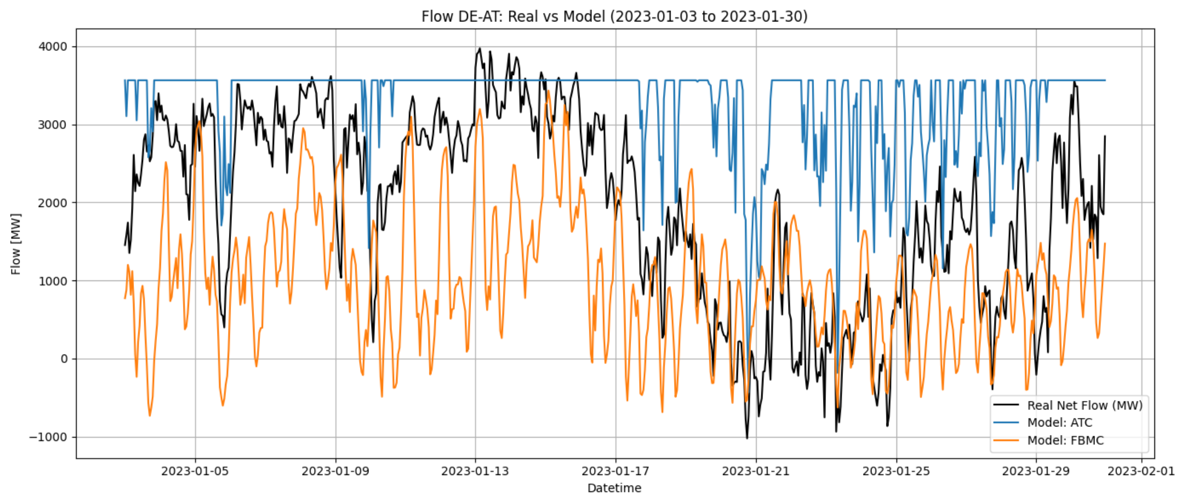


Figure 5.16: Flow on German-Austrian border where the orange line shows the FBMC flow, the blue line the ATC flow and the black line the flow in reality

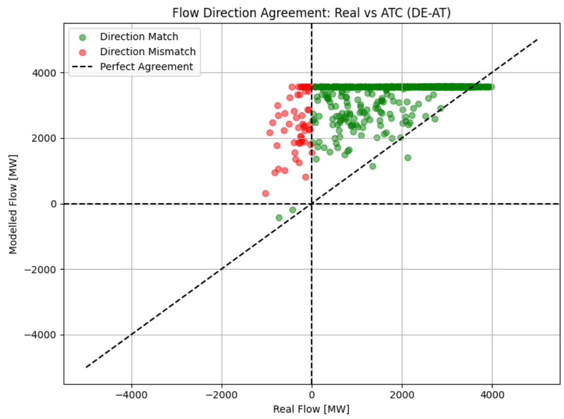


Figure 5.17: Scatter plot of ATC modelled vs real flows (DE → AT).

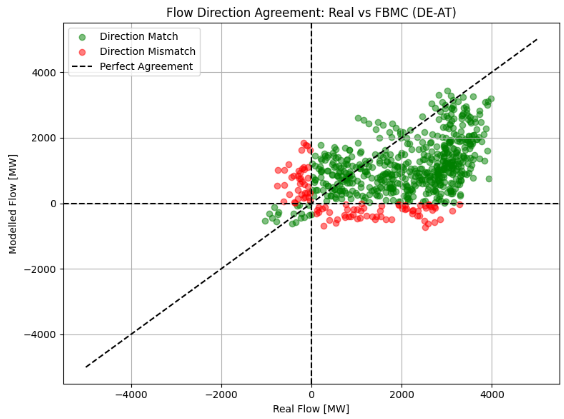


Figure 5.18: Scatter plot of FBMC modelled vs real flows (DE → AT). The model tends to capture flow direction and magnitude way more accurate.

In general the FBMC proves to be an improvement over the ATC model in terms of capturing flow direction and magnitude. In specific cases the model may exhibit a slightly bigger mismatch than the ATC model as is the case on the Belgian borders.

5.3. Conclusion on Verification and Validation

The constructed Flow Based Market Coupling model which has been presented in this chapter has been verified with respect to observed behaviour and real-world data. It has been shown that the model behaves as intended in terms of convergence properties, successfully reducing system imbalances and inter- and intrazonal overloads through iterative adjustment of surcharges and redispatch measures. The introduction of relaxed interconnection constraints confirmed the model's theoretical design by allowing full convergence to a near-zero imbalance and overload state. The relaxation of line constraints was performed solely to show the model behaves as intended and is in further analyses not done.

When compared to real-world data, the FBMC model exhibits a mixed performance depending on the metric of interest. In terms of electricity prices, the original ATC-based model continues to outperform the FBMC model, particularly for countries like the Netherlands and Belgium. This is not unexpected, as the ATC model was explicitly constructed and calibrated for price accuracy. In contrast, the FBMC model introduces additional network constraints and flow dependencies, which complicate price formation and slightly reduce price accuracy. Nonetheless, the FBMC model's pricing behaviour is consistent and explainable. For example, average prices in Germany are lower in the FBMC model due to decreased exports as a consequence of congestion pricing from Germany, leading to average lower prices in Germany.

With respect to cross-border flows, the FBMC model outperforms the ATC model on most borders, particularly in terms of flow direction and magnitude. This is to be expected as FBMC captures physical system behaviour through the nodal representation and modelling of physical flows whereas the ATC flows are based solely upon price differences and interconnection capacities. An interesting insight arises when looking at the Dutch system: flows between the Netherlands and neighbouring zones are generally limited under the FBMC model. This corresponds with the observation that the internal Dutch generation and load are relatively well balanced during the modelled hours. If generation occurs close to demand within the zone, the need for interzonal exchange is naturally reduced. The FBMC model captures this effect and reflects lower net positions and lower cross-border flows.

Some mismatches do occur, particularly on the Belgian borders, this mismatch is partly due to inconsistencies in input data but also loop flows may play a role in explaining observed discrepancies. These will be further analyzed in the zonal split scenarios. Overall, the FBMC model provides consistent and realistic results for assessing the effects of zonal configurations and is therefore deemed suitable for use in the next chapter on bidding zone reconfiguration.

5.4. Bidding Zone Scenarios Results

In this section, the effects of the proposed bidding zone splits for the Netherlands and Germany are assessed. The split configuration, as introduced in Chapter 4, is based on the recommendations put forward by ACER. Following the validation of the FBMC model in the previous section, the proposed split scenarios are implemented within the model to evaluate their impact on system behaviour.

An overview of the current bidding zone setup is first provided to establish a baseline (status quo), followed by a presentation of the most significant changes introduced by the new configurations. Subsequently, the newly defined bidding zones are introduced, and the key performance indicators identified in the literature review are evaluated. These indicators include congestion metrics (such as interzonal overloads and redispatch volumes), distributional effects (including zonal price levels and net positions), and measures of overall market efficiency (such as price volatility and the frequency of extreme price events).

The simulations are conducted for two representative periods: January and April 2023, April is shown in this chapter. January and April have been chosen in order to observe potential seasonal differences.

First, the system status quo is presented. Then, per scenario, the most notable outcomes are discussed. A complete overview of all scenario results per performance indicator is then provided.

5.4.1. Status Quo

To illustrate the differences between the original bidding zone configuration and the post-split system, a brief overview of the current system status is first provided, including relevant information on system layout and the spatial distribution of resources. The analysis focuses on the simulation of April 2023.

Figure 5.19 presents the interconnectors between the Netherlands, Germany, and Belgium along with their respective geographical locations. The modelled (and actual) interconnections between the Netherlands and Germany include Gronau–Hengelo, Doetinchem–Niederrhein, Maasbracht–Oberzier, and Diele–Meeden.

Figure 5.20 shows the distribution of electricity demand across the modelled nodes. In the Netherlands, most electricity consumption is concentrated in the Southern part of the country, particularly in the Randstad region, while the Northern regions show relatively low demand. In Germany, demand is more evenly distributed, although node density is significantly higher in industrialized areas, particularly in the Southern regions such as the Ruhr area. One node should be noted especially as Figure 5.20 does not do it justice, this is Berlin, in which the load concentration is, as expected, way higher than in surrounding nodes.

Figure 5.19: Interconnectors NL-DE-BE, all modelled interconnections (and therefore real ones) are shown in this figure

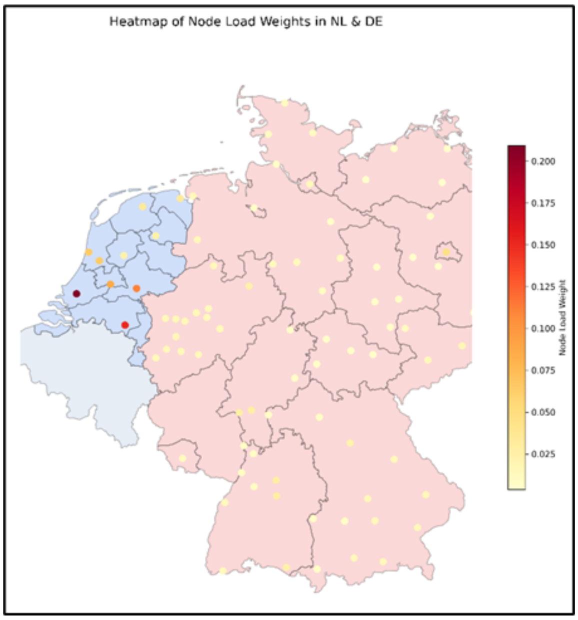


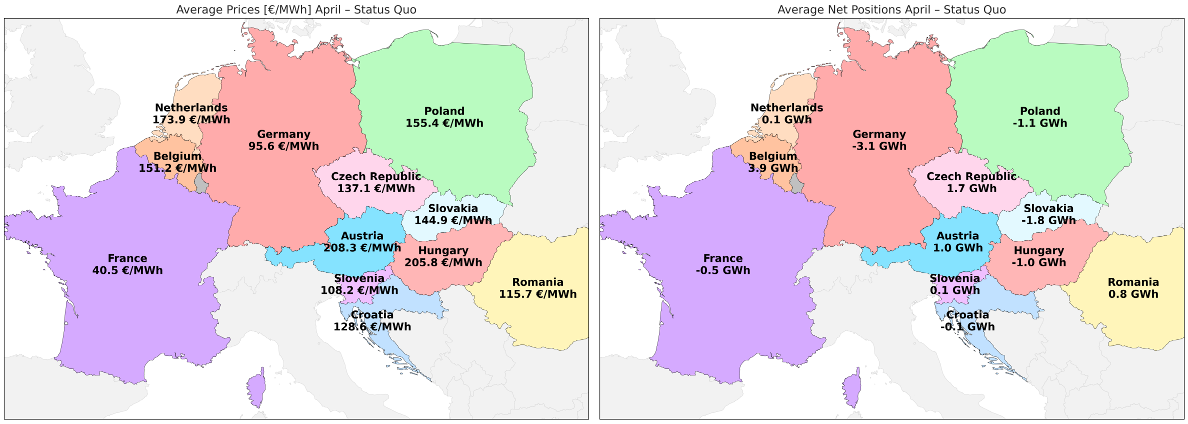
Figure 5.20: Distribution of load in NL and DE, most Dutch load is concentrated in the Randstad, the concentration of nodes in the Ruhr area is especially high making for a lot of demand as well.

Distributional Effects

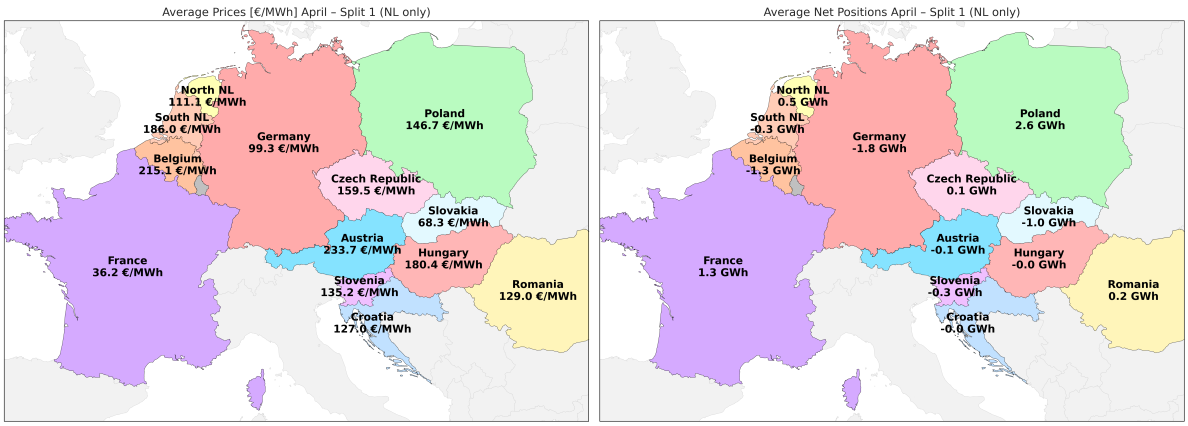
With respect to the distributional effects e.g. how prices and net positions evolve under the different split scenarios the average hourly day ahead electricity prices and average net positions are shown in Figure 5.21. the results are shown averaged over the month of April 2023.

In general, electricity prices in April 2023 were observed to be quite high. Please note that in Figure 5.21 a negative net position means exporting and positive means importing. Important observations with respect to the status quo include the fact that Belgium is initially a big importing zone. We have already commented on the fact that Belgium in January was represented as a importing zone whereas this in reality seemed to not always be true. In the status quo, Germany takes on the biggest exporting role whereas the Netherlands tends to remain relatively neutral in the sense that it does not export or import big amounts of electricity.

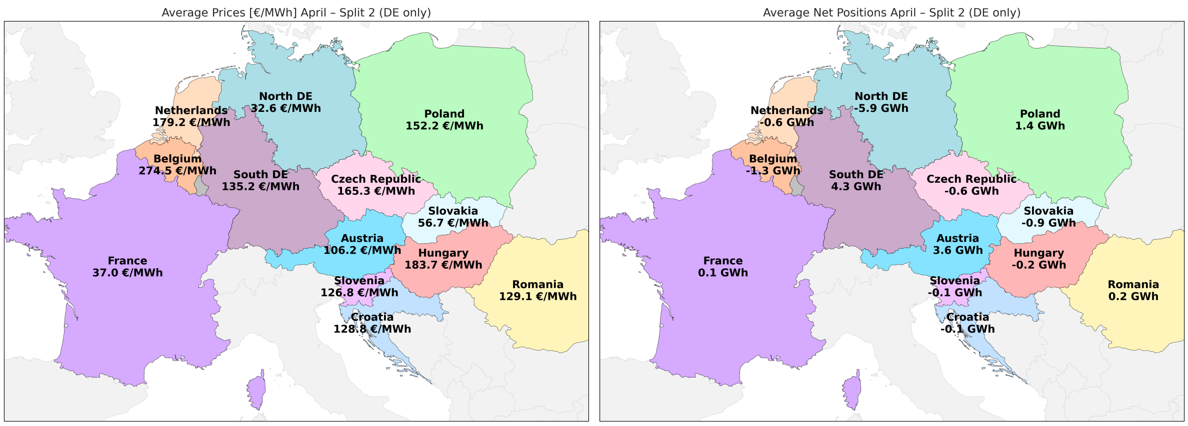
Per split scenario there will be references back to this overview, the results are shown together in order to be able to make a comparison between all split scenarios at once.



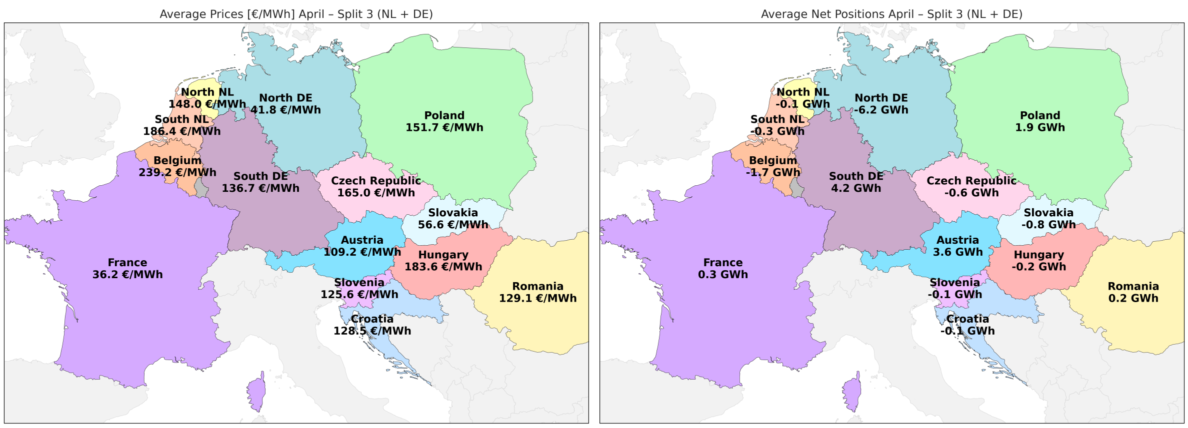
(a) Status Quo (a)



(b) NL Split (Split 1) (b)



(c) DE Split (Split 2) (c)



(d) DE Split (Split 2) (c)

Figure 5.21: Maps of Average Day-Ahead Prices and Net Positions in April across all Split Scenarios

Congestion Metrics April To make a meaningful distinction between the flow patterns observed in the split scenarios and the status quo, the statistics for the status quo (April) are presented in full and subsequently referenced when relevant to highlight shifts in patterns. In the following split scenarios, only results deemed significant will be shown.

Zone Pair	$\rightarrow$ Cong (%)	$\rightarrow$ Util (%)	$\leftarrow$ Cong (%)	$\leftarrow$ Util (%)
AT–CZ	0.00	20.34	0.00	0.15
AT–HU	0.00	1.79	0.00	1.59
AT–SI	0.00	0.04	0.00	33.37
BE–DE	0.00	0.05	40.32	75.33
BE–FR	0.00	0.00	8.06	66.45
CZ–SK	0.00	0.00	0.00	35.85
DE–AT	0.00	16.48	0.00	1.13
DE–CZ	0.00	14.01	0.00	0.04
DE–FR	5.78	71.20	0.00	0.00
DE–PL	0.67	4.98	47.98	69.07
HU–HR	0.00	23.47	0.00	0.21
HU–RO	8.33	69.84	0.00	0.00
HU–SI	0.00	0.66	0.00	3.89
NL–BE	0.00	10.11	0.00	0.17
NL–DE	0.00	0.00	0.00	9.33
PL–CZ	0.00	17.15	0.00	0.24
PL–SK	0.00	0.00	0.00	52.15
SI–HR	0.00	0.03	0.00	25.20
SK–HU	0.00	5.32	0.00	0.70

Table 5.4: Congestion metrics Status Quo, the columns indicate the utilization of lines in both directions measured over the entire time horizon.

Interestingly, what we see here is that Belgium is indeed a big importing zone, the Belgian - German interconnector shows to be congested 40% of the time. This is most likely causing the flow on the French - Belgian interconnector as well due to a loop flow. To investigate this further the flows on the Belgian - French, Belgian - German and German - French interconnectors is plotted in Figure 5.22 (January is shown as this effect has previously been described in the verification, the effect is the same for April).

The figure illustrates the following: the blue line represents the Belgian–German interconnector, which has a capacity limit of 1 GW. The orange line shows the German–French interconnector, and the green line represents the Belgian–French interconnector. Red dots are plotted during hours when the Belgian–German interconnector is congested.

A key observation is that during these congested hours (red dots), the flow on the Belgian–French interconnector (green line) is also often close to its capacity, with power flowing into Belgium. This may be due to increased import needs within Belgium. However, the loop flow pattern becomes evident on the German–French interconnector.

In Figure 5.21, for instance, we observe a French price of €40.5/MWh and a German price of €99.3/MWh. From an economic perspective, this price difference should not incentivize flow from Germany to France. Yet, during the congested hours, the flow on the German–French border is highest, which suggests that it may be indirectly caused by the congestion on the Belgian–German interconnector.

While this does not constitute definitive proof, it is a strong indicator of loop flow behaviour.

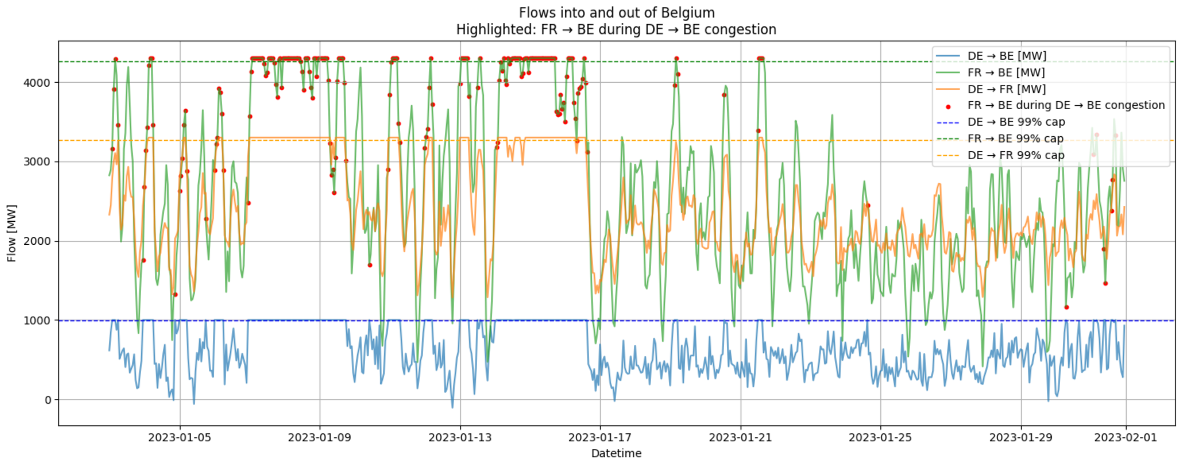


Figure 5.22: Visualization of potential loop flow behavior involving Belgium, France, and Germany. The blue line represents the Belgian–German interconnector (1 GW limit), the green line the Belgian–French interconnector, and the orange line the German–French interconnector. Red dots indicate hours when the Belgian–German interconnector is congested.

Furthermore, the required redispatch is shown for all splits at once. Per split, there will similarly be references back to the required amount of redispatch. The redispatch required relative to the status quo is shown in Figure (5.23). Keep in mind that the absolute redispatch amounts have no meaning, there is therefore no unit of measurement, and the results should only be interpreted as changes with respect to the status quo.

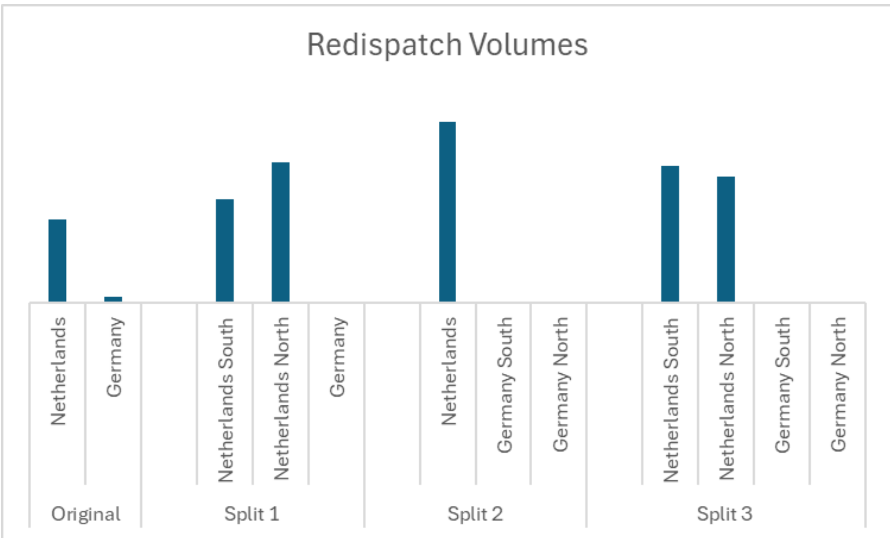


Figure 5.23: Required redispatch needs per split scenario, there is no unit of measurement as the results should only be interpreted as opposed to the status quo. On the left the status quo redispatch needs (volumes) are shown

Market Efficiency

Similarly, references back to the initial market efficiency metrics which are shown in Table 5.5 and 5.6 are made, changes in the frequency of extreme price events and price volatility will be highlighted.

Zone	Hits -100 €/MWh (%)	95th % Threshold	>95th % Freq (%)
NL	1.61	261.22	5.11
BE	1.08	239.60	5.11
DE	6.99	200.83	5.11
FR	0.00	90.55	5.11
AT	0.00	277.87	5.11
PL	0.00	177.97	5.24
CZ	0.00	193.68	5.11

Table 5.5: Extreme price event frequency and thresholds per zone. The *-100€/MWh* column indicates how often the price reached this floor value.

We observe that Germany most often hits the minimum price threshold of -100 €/MWh, followed (with a big margin of 5%) by the Netherlands. This is to be expected as Germany is, among the shown countries, the one with the highest amount of installed renewable capacity (IEA, 2024). It is therefore most likely to reach the minimum price threshold in periods with high renewable generation.

Zone	Avg $\|\triangle$Price$\|$ [€/MWh]
NL	25.36
BE	29.15
DE	19.66
FR	6.44
AT	9.92
PL	6.71
CZ	13.07

Table 5.6: Average absolute hourly price change per zone. Belgium and Netherlands show the highest short-term price volatility.

Table 5.6 shows the average absolute hourly price change. It is observed that Belgium exhibits the highest price volatility, followed by The Netherlands and Germany. In the case of Belgium this may be due to several reasons, Belgium may be dependent on imports from other countries, which stemming from the loop flow explanation, is not unlikely. It may also be an effect of the congestion on the Belgian border causing Belgian prices to increase steeply when heavily congested. This is, combined with the congestion metrics shown in Table 5.4, also not an unlikely explanation. There is no clear indicator which tells us what is the exact cause but the most likely explanation is the combination of the two given possibilities.

5.4.2. Split 1 Netherlands North and -South

In this section the first split scenario shall be investigated, the first split scenario consisted of splitting The Netherlands in a Northern and a Southern zone while leaving the German zone as is.

Distributional effects

To assess the distributional effects of splitting The Netherlands into a Northern and a Southern zone Figure 5.21 is again observed. We see that splitting the Netherlands manifests itself as lower average hourly prices for the Netherlands North than it does for the Netherlands South. The Netherlands-North gets an average hourly price in April of 111.1 €/MWh and the Netherlands-South of 186.0 €/MWh, a significantly higher price. The Dutch electricity mix mostly consists mostly of natural gas (IEA, 2024), a relatively expensive fuel. The price in both the newly formed zones is therefore not implausible, what is interesting however is the big difference in price. In order to find an explanation for this occurrence the congestion- and the market efficiency metrics shall give a clearer overview.

With respect to the distributional effects itself another interesting result occurs. Belgium, instead of being a big importer has become an exporting zone, this translates to higher prices in Belgium. On the other hand, Poland becomes a big electricity importer with a 2.4 GWh average hourly import, it becomes the biggest importing zone in the system whereas Germany is still the biggest exporter. To provide a meaningful answer as to why this occurs the congestion metrics must be investigated.

Market Efficiency

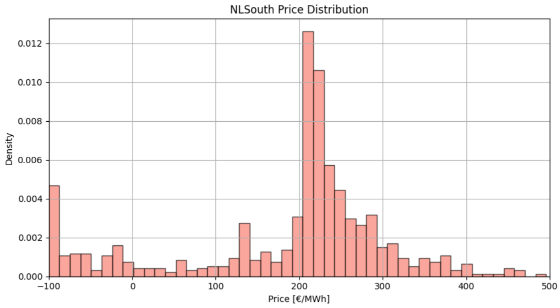
The main question concerning the market efficiency metrics is with respect to the price difference between the Netherlands North and South. The reconfiguration of the Dutch bidding zones clearly reveals interdependencies with respect to market efficiency in the Netherlands.

Most electricity demand is located in the South of the Netherlands whereas there is a relatively small portion of load assigned to the North. Access to renewable energy sources is mostly attributed to the South of the Netherlands as most offshore wind parks are located in front of the South/North Holland provinces. As a result The Northern part of the Netherlands exhibits a more stable price pattern, Δ9.71 €/MWh as opposed to Δ44.02 €/MWh average change per hour, partly due to lower demand and partly due to less reliance on renewable energy sources.

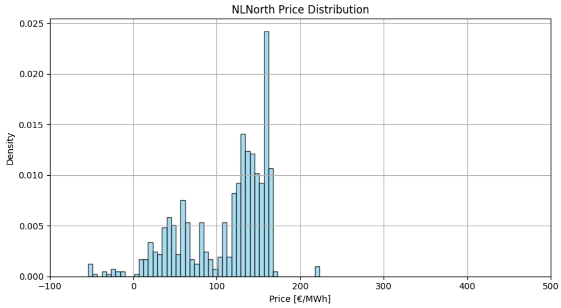
Zone	Avg $\|\triangle$Price$\|$ [€/MWh]
NL South	44.02
NL North	9.71
BE	25.03
DE	18.19

Table 5.7: Average price volatility in split scenario 1.

The South on the other hand becomes more prone to extreme price events (Figure 5.24) as the mediating effect (on price volatility) which the North previously had becomes limited. This is shown in Table 5.8 in which the frequency of extreme price events is displayed indicating that the South of the Netherlands hits the minimum price threshold 4.57% of the time (the North 0%) whereas this was originally 1.6% in the Netherlands as a whole. this is however still not a justification of the price difference between the Dutch zones.



(a) NLSouth Price Distribution



(b) NLNorth Price Distribution

Figure 5.24: Price distributions for NLSouth (left) and NLNorth (right), NL South has more negative price hours but also more extremely high prices.

Zone	Hits -100 €/MWh (%)	95th % Threshold	>95th % Freq (%)
NLSouth	4.57	359.64	5.11
NLNorth	0.00	162.83	5.11
BE	0.00	291.81	5.11
DE	6.59	191.44	5.11

Table 5.8: Frequency of extreme prices per zone. Includes share of hours with -100 €/MWh prices and prices above the 95th percentile.

Congestion Metrics

To give a meaningful answer to the question of price differences within the Netherlands as well as the shift in net positions from Belgium and Poland the congestion metrics are assessed. Table 5.19 gives the general overview with respect to the flows which are deemed interesting with respect to this split.

Firstly the newly emerging interzonal flow which was previously deemed intrazonal of course, from the Netherlands South to the Netherlands North, is investigated. In Figure 5.25 and Table 5.9 it can be observed that the flow from the North to the South (and vice versa) is on average quite low. This is in accordance with the earlier observation done with respect to the Dutch interzonal flow which was on average low as well.

Zone Pair	→ Cong (%)	→ Util (%)	← Cong (%)	← Util (%)
AT–CZ	0.00	3.99	0.00	0.89
AT–SI	0.00	0.13	0.00	24.86
BE–DE	9.95	38.30	6.45	16.83
BE–FR	0.13	24.06	0.00	6.37
BE–NLSouth	0.00	9.28	0.00	1.10
DE–AT	0.00	6.36	0.00	11.93
DE–CZ	0.00	3.42	0.00	2.58
DE–FR	0.27	19.43	0.00	2.24
DE–NLNorth	0.00	6.56	0.00	8.94
DE–NLSouth	0.00	1.79	0.00	1.10
DE–PL	40.73	66.07	1.61	6.59
NLSouth–NLNorth	0.00	11.25	0.00	0.05
PL–CZ	0.00	18.18	0.00	0.11

Table 5.9: Congestion metrics for each zone pair.

Interestingly, although average prices are lower in the North, flows often go from the South to the North, especially during hours of negative prices when the South has excess renewable production. However, the reverse is rarely the case. The North is generally able to meet its own demand but lacks surplus capacity to significantly support the South during periods of scarcity, this is displayed when investigating “when” flows occur. During negative price hours the North never exports to the South (0%) whereas the portion of hours where the Southern price was negative and exporting to the North is around 20%. As a result, the North benefits from the South when the South has excess renewable generation, the South does however not benefit from the North as the North does not have the capacity to supply the South as well.

The fact that the new interzonal flow between Netherlands-North and -South remains relatively low is interesting. One would expect a clear directional flow if one side had structural surplus or deficit. Instead, the limited exchange suggests that both subzones face their own internal bottlenecks.

This aligns with the high redispatch volumes observed in both zones (Figure 5.23). The likely interpretation is that internal network constraints within each Dutch zone are limiting the ability to transfer power even within the country, meaning the zones are forced to resolve imbalances locally through redispatch.

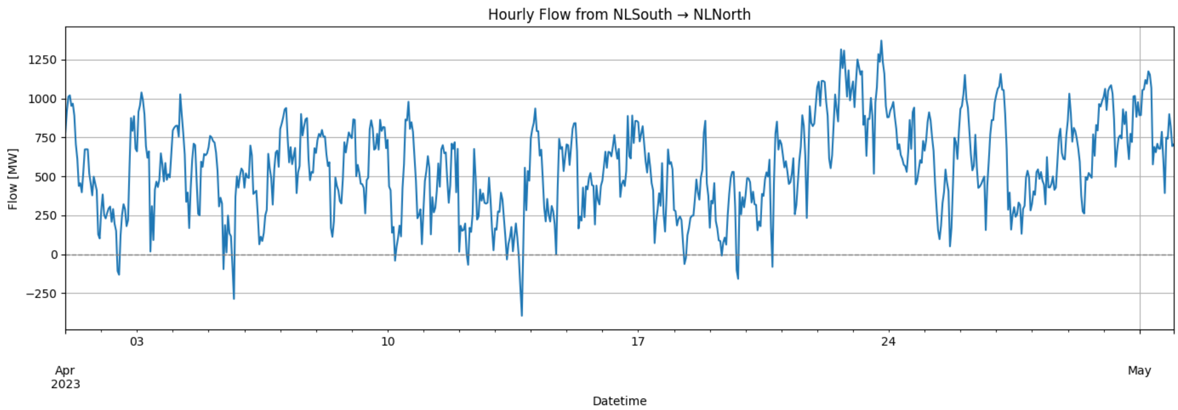


Figure 5.25: Hourly flow in April 2023 from the Netherlands South to the Netherlands North, the flow is almost positive in the direction South to North

Another interesting observation is that the interconnectors from the North to Germany become more active, especially towards Meeden-Diele and Gronau-Hengelo, as opposed to the South of the Netherlands which does not show an increasingly lot of flow towards Germany. Figure 5.26 shows this over time. The overall magnitude of flow is observed to be rather low, for the Netherlands-South to Germany more so than for the Netherlands-North to Germany. A possible explanation hereof can be again be found in the redispatch metrics, both the flow from the South and the North of the Netherlands towards Germany (and Belgium) is rather low once again indicating insufficient intrazonal capacity in the Netherlands.

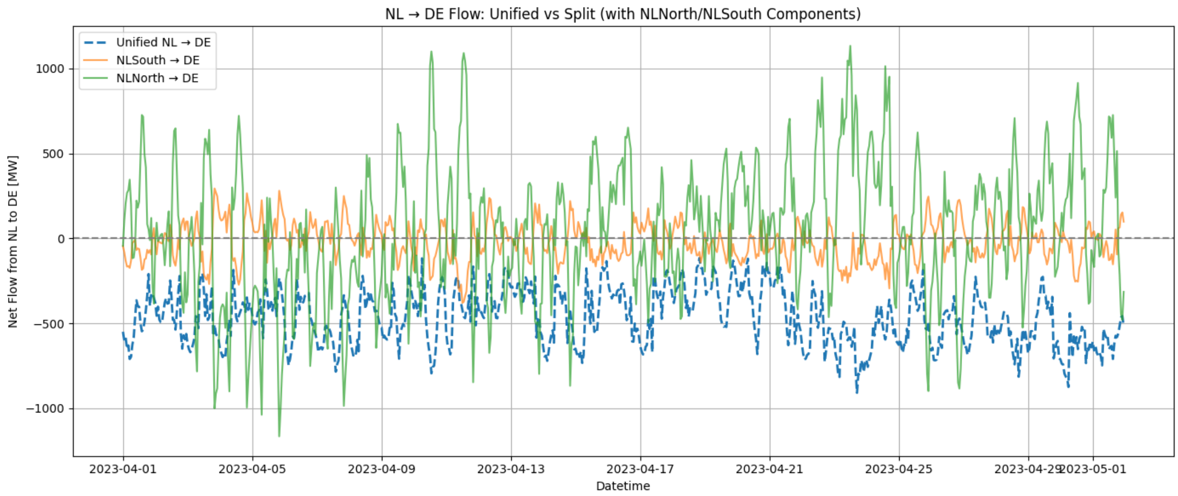


Figure 5.26: Flow from Germany to the Netherlands during the status quo (green line) and during the first split scenario, NL South - DE (orange) and NL North - DE (blue).

When the initially shown distributional effects are investigated, comparing split scenario 1 with the status quo, we observe a significant difference in the Belgian price which has increased with approximately €60. We similarly see a shift from Belgium being a big importing zone to being a big exporting zone.

This outcome may be influenced by several overlapping factors, such as the altered network topology, changed congestion patterns, and localized price signals. However, no single explanation fully accounts for the magnitude of the shift. Rather, it underscores the highly interconnected nature of the European electricity system, where changes in one region can result in big differences through the rest of the network. The resulting behavior illustrates how even regional changes can lead to significant, system-wide distributional effects.

5.4.3. Split 2 Germany North and -South

This section will focus on investigating split scenario 2 which consisted of splitting Germany in a Northern and a Southern zone while leaving the Netherlands untouched.

Market Efficiency

In this split scenario the market efficiency metrics will be shown first as the price distributions in Germany-North and Germany-South will be often referred back to in the explanation of the distributional effects and congestion metrics. The price distribution shows an enormous amount of negative price hours in Germany-North whereas the South similarly exhibits some negative price hours but overall has way higher prices as opposed to the North (Figure 5.27).

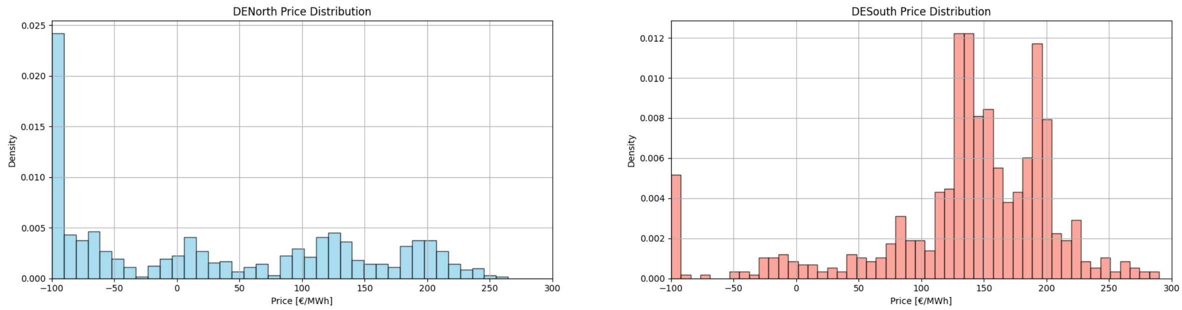


Figure 5.27: Price Distribution Germany North (left) and South (right) – Split Scenario 2

As opposed to the initial average price change per hour, Germany-North exhibits a more stable price pattern (mostly negative) whereas Germany-South exhibits a more volatile price pattern. This is most likely due to the prices in Germany-North being stable at the minimum price threshold of -100 €/MWh.

Zone	Avg $\|\triangle$Price$\|$ [€/MWh]
NL	26.68
DESouth	23.08
DENorth	12.52
BE	38.50

Table 5.10: Average price change Germany North and South

Distributional Effects

Perhaps the most striking occurrence in scenario 2, is with regard to the distributional effect which show that Germany North becomes a major exporter with an average net position of -5.9 GWh and an average price of €32,6/MWh due to renewable energy surpluses. The South on the other hand becomes a large importer, facing high prices of €135.2/MWh and high demand concentrations with an average net position of approximately +4 GWh. This is to be expected, since as previously mentioned the demand in Southern Germany is highly concentrated due to high industrialization in the Ruhr area. With respect to the Netherlands we see an increase in exports possibly indicating that the Netherlands is trying to facilitate the Southern German demand. Similarly to the previous split scenario, Belgium is a big exporter trying to facilitate Germany in meeting demand, this effect is even more reinforced by Germany now being a huge importer due to the splitting of the bidding zone. This effect is further observed with respect to the congestion metrics.

Congestion Metrics

Belgium trying to meet German demand is causing the Belgian – German interconnection to become congested which can be seen in table 5.11 where the Belgian – German border is congested almost 19% of all hours. Referring back to Figure 5.20 showing the nodal demand concentration it makes sense that Belgium is the appointed party, having to comply with the huge Southern German demand as most demand is located near the Belgian border. The French - Germany-South border is similarly increasingly utilized as opposed to when solely the Netherlands is split.

The flow difference as opposed to the status quo concerning the Belgian-German border is plotted in figure 5.28, showing that flows have shifted direction following the German split.

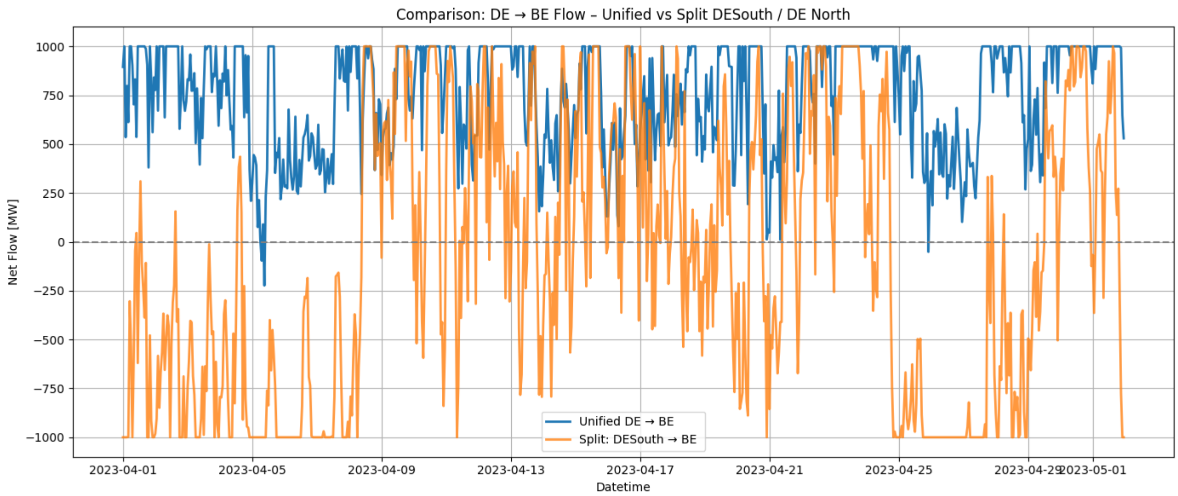


Figure 5.28: Flow reversal over the Belgian-German interconnector, blue shows the original flow, whereas orange shows the flow when split

Interestingly, the flow from Germany North towards Poland seems to be lower when Germany is split, compared to when only the Netherlands is split. While Poland still benefits from relatively cheap imports, the effect is less strong. A possible explanation is that Germany North has a large share of renewable energy, when Germany as a whole is not responsible for supplying the South anymore, there is simply less need to produce electricity overall. In other words, in the single-zone case, Germany-North has to generate more, both for itself and for Germany-South, which causes more flow towards neighboring regions, including Poland. When split, the North mostly covers its own demand with cheap renewables and doesn't need to "overproduce", which results in less flow leaving the zone. So even though prices in Germany-North remain low, the actual export volumes drop, including those to Poland.

Austria also benefits from increased flow Germany-South, this seems counterintuitive considering the huge South-German demand. A possible explanation can be found when again observing the nodal demand concentration. The demand in the Bavaria (Bayern - the region bordering Austria) is relatively low as opposed to the Ruhr area. Manske et al. (2025) report on parts of Bavaria having surplus renewable electricity as opposed to the electricity demand. Austria could benefit from this surplus during hours with high renewable generation. There is however still huge demand to be fulfilled in Germany-South, as a result, Belgium becomes a major exporter and experiences high congestion on its interconnection with Germany.

Table 5.11: Congestion Metrics for split 2 DE-North DE-South

Zone Pair	→ Cong (%)	→ Util (%)	← Cong (%)	← Util (%)
AT–DESouth	0.00	0.55	18.01	62.43
BE–DESouth	18.95	35.78	8.60	26.65
BE–FR	1.34	38.33	0.67	5.97
CZ–DENorth	0.00	5.46	0.00	0.24
CZ–DESouth	0.00	6.89	0.00	0.12
DESouth–DENorth	0.00	0.00	1.08	57.78
FR–DESouth	3.09	40.57	0.00	1.00
NL–BE	0.00	7.90	0.00	2.60
NL–DENorth	0.00	12.39	0.00	3.72
NL–DESouth	0.00	6.76	0.00	0.21
PL–DENorth	1.88	11.88	2.82	27.97

The huge discrepancy between the Northern excess in renewable generation and the high concentration of demand in the South results in significant flow from Germany North to Germany South. This is clearly reflected in the North–South German interconnection flows, which peaks as high as 10,000 MW (the limit) (Figure 5.29). Despite the large transfer volumes, the interconnection is only congested 1.08% of the time indicating that the assumed transfer capacity may be overestimated.

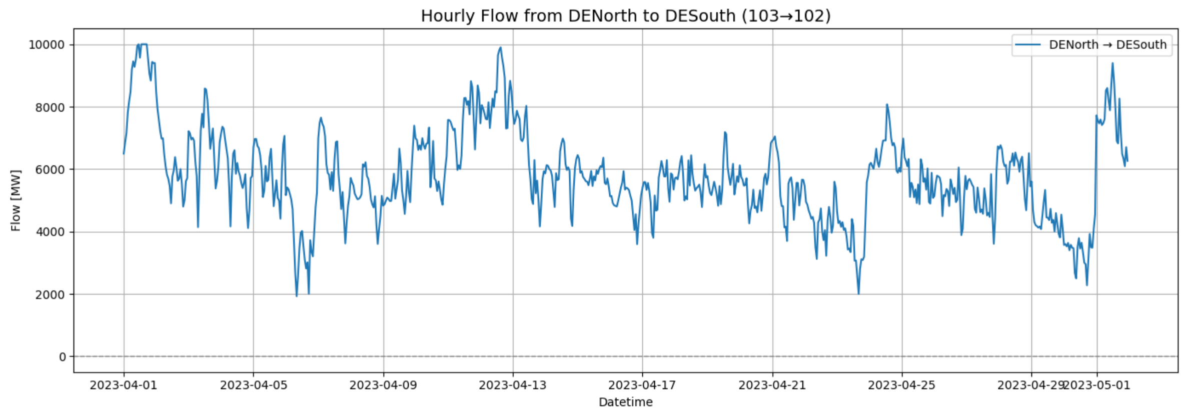


Figure 5.29: Flow from Germany North to Germany South after splitting. Flow is always positive, so from North to South, April 2023

Under the distributional effects paragraph it was rationalized that the Netherlands possibly tried to facilitate the demand in Germany-South by exporting more. In Table 5.11 however, we do not observe a significant increase in flow from the Netherlands to Germany-South. The flow from the Netherlands to Germany-North is similar to the first split scenario higher than in the South. The most likely explanation of the low flow, especially from the South of the Netherlands, is likely due to the increase in required redispatch (see Figure 5.23) in the Netherlands as a result of the German split. That is because the intrazonal flow within the Netherlands may ”overshadow” the interzonal flow towards Belgium and Germany, a logical consequence would then be high redispatch needs within the Netherlands itself.

In the first split scenario, Netherlands North and -South, we observed an increase in redispatch needs mainly in the Netherlands-North, in the current split scenario, indeed, the redispatch needs for the Netherlands as a whole have increased significantly as opposed to the status quo, confirming that most likely the interzonal flow is limited by intrazonal capacity. A possible explanation for the increased redispatch needs in the Netherlands itself is the increased flow from the Netherlands-North towards Germany-North. This would possibly also mean an increase in flow from the Netherlands-South towards the Netherlands-North because the North exports more towards Germany. It is only possible to comment on this aspect with increased certainty when the Netherlands as well as Germany are split.

The increased redispatch needs in the Netherlands as a whole could possibly be an incentive for the Netherlands to split as well, as this could make the intrazonal congestion explicit. In the following split scenario we observe the effects of the The Netherlands splitting as well as Germany.

5.5. Split 3 Germany North and -South / Netherlands North and - South

In this section the effects of splitting both Germany and the Netherlands in a Northern and a Southern zone will be investigated.

Distributional Effects

Overall the third split scenario shows fairly similar results to the second scenario with respect to the distributional effects (see Figure 5.21). It is seen that the impact of splitting Germany substantially outweighs splitting the Netherlands. There are no significant changes observed with respect to prices except for the Netherlands-North which increases in price significantly going from 111.1 €/MWh to 148.0 €/MWh. This effect is noticed as well when taking into regard the net positions, the Netherlands-North goes from an importing zone (importing from NL South mainly in split scenario 1) to being an exporting zone. Other notable changes include the increase in imports in Poland and the increased exports from Germany-North. As the net positions in other zones remain relatively similar to what is observed in the second split scenario this indicates that the flow from the Netherlands-North may be rerouted to Poland through Germany-North. To accurately assess this however the congestion metrics must be investigated in more detail.

Market Efficiency

With respect to the market efficiency metrics, no particularly striking changes are observed when comparing the simultaneous split to the scenarios in which only the Netherlands or only Germany is split. What is interesting, however, is the apparent stabilizing effect on price volatility.

Splitting both the Netherlands and Germany seems to lead to a more balanced system, where increased interaction between zones contributes to more stable prices overall. The effect is rather small but still noticeable and it can be logically reasoned that the average price change would only converge more when flows between zones increase.

Table 5.12: Average Hourly Absolute Price Change per Zone, split 3

Zone	Avg $|\triangle$Price$|$ [€/MWh]
NLSouth	42.15
NLNorth	18.36
DESouth	22.16
DENorth	14.95
BE	24.42

Congestion Metrics

The interaction between the North of the Netherlands and the North of Germany is increasingly expressed showing a significant increase in flow, the South on the other hand is again less active indicating that the intrazonal flow still overshadows the interzonal flow which is again reiterated by the persisting congestion in the Southern Netherlands. Figure 5.30 shows the flow from NL-North to DE-North and NL-South to DE-South.

The flow on the Germany-North to Germany-South interconnection is significantly higher than the flows on the Dutch interconnections. Interestingly, and as hypothesized, the flow from Netherlands-North to Germany-North is increased from 12.39% in the second split scenario, 8.94% in the first split scenario to 17.68% in the third split scenario.

Table 5.13: Congestion Metrics between Zone Pairs in split scenario 3

Zone Pair	→ Cong (%)	→ Util (%)	← Cong (%)	← Util (%)
AT–CZ	0.00	0.05	0.00	5.64
AT–DESouth	0.00	0.44	17.88	63.33
AT–HU	0.00	0.53	0.00	4.11
AT–SI	0.00	1.05	0.00	17.51
BE–DESouth	27.42	43.86	9.01	21.09
BE–FR	2.82	38.45	0.54	6.00
BE–NLSouth	0.00	6.59	0.00	4.35
CZ–DENorth	0.00	5.54	0.00	0.12
CZ–DESouth	0.00	6.85	0.00	0.04
DESouth–DENorth	0.00	0.00	1.08	58.36
FR–DESouth	2.69	36.58	0.00	2.07
NLNorth–DENorth	0.00	17.68	0.00	3.04
NLSouth–DESouth	0.00	5.13	0.00	0.45
PL–CZ	0.00	5.87	0.00	3.28
PL–DENorth	0.00	4.68	4.03	35.53
NLSouth-NLNorth	0.00	0.00	0.00	20.11

This indicates that flow from the Netherlands-North is possibly rerouted to Germany-South through Germany-North as the South of the Netherlands does not have the intrazonal capacity to accommodate the flow from the Netherlands-North towards Germany-South. This partly confirms our statement made in the previous split scenario where it was hypothesized that the flow from the Netherlands-South towards the North would be increased. This however purely an indication and cannot be used as ”proof” as the zonal configuration has changed possibly altering flow patterns again.

This explanation is nevertheless again emphasized when the redispatch volumes in the Netherlands are taken into regard. We observe that the redispatch volumes in the Netherlands-North drop slightly as a result of the increased flow towards Germany-North. A possible explanation for the increase in prices is that the exports towards Germany outweigh the imports from the South. What is more likely however, is that the due to the exports towards Germany, more expensive generation has to be switched on, possibly in less congested areas but nonetheless more expensive. There is no way of explicitly confirming this hypothesis as we would need to observe nodal prices in the system.

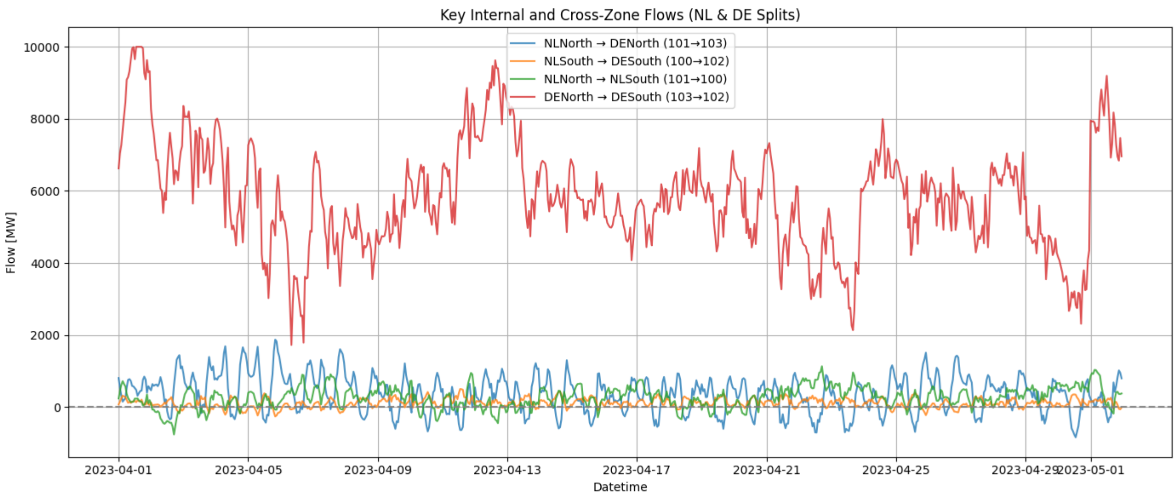


Figure 5.30: Previously intrazonal (now interzonal) and interzonal flows in and between the Netherlands and Germany. The red line shows the German North-South indicating way higher flow than on the other interconnections. The green line shows the Dutch flow.

Nonetheless, the observed patterns in interzonal flows and redispatch volumes strongly support the idea that structural bottlenecks, combined with newly emerged cross-border interdependencies, are the most likely drivers behind the increased prices and redispatch needs. The interactions between zones, combined with the shifting dynamic flow patterns, show how interconnected the system as a whole is. Changes in one zone can directly (or indirectly) influence outcomes in another, reinforcing the idea that zonal outcomes cannot be seen in isolation and must be evaluated in the context of broader system-wide dependencies.

5.6. Split Scenario Outcomes

This section will be dedicated to briefly summarizing the most important outcomes from the simulation of the reconfigured bidding zones in The Netherlands and Germany along with the associated consequences. In doing so we'll answer the following sub-questions:

3: *How does the reconfiguration of the Dutch and German bidding zones affect system-wide market efficiency and congestion?*

4: *How does the reconfiguration of the Dutch and German bidding zones affect system-wide zonal market outcomes and system interactions?*

In the simulation, three scenarios were analyzed:

- **Scenario 1**: Netherlands split into a Northern and a Southern zone.
- **Scenario 2**: Germany split into a Northern and a Southern zone.
- **Scenario 3**: Combined split of both countries simultaneously.

To give a clear answer to both sub-questions the consequences for the distributional effects shall be debated first as to show the effect on zonal market outcomes and interactions. The distributional effects are, as noticed in the split scenario results, often explained by the dynamics observed through the congestion and market efficiency metrics.

System-Wide Distributional Effects and Interactions

Split Scenario 1 has resulted in surprisingly pronounced effects on the system as a whole. For the Netherlands itself, the main effect is that the Netherlands-South became a high-price zone, while the Netherlands-North experienced lower prices. In terms of interactions with other zones, the Netherlands' influence appears relatively limited compared to, for instance, Germany. This is likely due to high intrazonal flow, which overshadows potential interzonal exchanges.

Perhaps the most interesting effect, though lacking a complete explanation, is the switch from Belgium being a net importer to becoming a net exporter, accompanied by a price increase of roughly €60. Simultaneously, Austria and Poland transition from being net exporters to importers. While this outcome is likely influenced by multiple overlapping factors, altered network topology, congestion, and price signals, no single explanation fully accounts for the shift. Rather, it reiterates the highly interconnected nature of the European electricity system, where changes in one region can result in significant effects across the network.

Split Scenario 2 has led to the most drastic system-wide effect, completely restructuring the electricity system compared to the status quo, with pronounced effects on prices and net positions. Germany-North becomes a huge exporter (average net position: -5.9 GWh) with low average prices due to high renewable generation and relatively low demand. Germany-South, in contrast, becomes a high-price, high-import zone. This directly impacts adjacent zones, especially Belgium, by turning them into major exporters with steeply increased prices in Belgium as a consequence. Interestingly, the contrary is observed in Austria which benefits from the German North-South split through increased imports from Germany.

Split Scenario 3, where both the Netherlands and Germany are split into North and South zones, shows that the effects of the German split are more strongly felt system-wide than the Dutch split. We observe only small changes compared to the second split scenario,except in the Netherlands itself. Here, the Netherlands-North becomes an exporting zone and sees higher prices, while the South remains roughly the same. To explain these distributional effects, the congestion and market efficiency metrics are explored in more detail in the following section.

System-Wide Market Efficiency and Congestion

To better account for the distributional effects observed above, the market efficiency metrics, redispatch volumes, line utilization, and price volatility have been used.

While the impact of splitting the Netherlands alone (Split 1) leads to internal congestion and price asymmetry between North and South, its broader influence in terms of increased interaction from the

Netherlands with other zones is limited. This is confirmed by increased redispatch volumes in the Netherlands-South and North, pointing to structural bottlenecks within the zone itself. In other words, the lack of intrazonal capacity in the Netherlands likely restricts interzonal exchanges with neighboring countries, explaining the relatively low cross-border effects.

In Split 2, where only Germany is split, redispatch needs in Germany are eliminated. This corresponds with the German North-South interconnection occasionally reaching its limit, suggesting that the North–South bottleneck is effectively made explicit, reducing the need for corrective actions. The redistribution of flow also shifts cross-border interactions significantly, with Belgium and Austria especially being influenced. The high demand concentration near the Belgian border likely causes Belgium to be designated to cope with the increased Southern German demand, whereas Austria seems to profit from the lower demand and higher renewable availability in the Bavaria region.

Split 3 introduces both Dutch and German splits. While it does not change the dynamics as drastically as Split 2, it does stabilize price volatility across zones. The flow from the Netherlands-North to Germany-North increases slightly. This increase appears to ease internal pressure in the North, as seen by a slight drop in redispatch volumes. However, the Netherlands-South remains constrained indicating that there is indeed a lack of intrazonal capacity.

Ultimately, the observed patterns in interzonal flows, redispatch needs, and price stability help clarify the distributional outcomes discussed earlier. They reinforce the notion that structural constraints and emergent cross-zonal interdependencies are central drivers of price changes and congestion. The system-wide effects highlight the importance of interpreting zonal configurations not in isolation but in the full context of a highly interconnected European grid.

6
Discussion

By comparing the outcomes across different configurations, it is evaluated how the resulting changes affect market efficiency and congestion metrics, and how these, in turn, explain the observed distributional effects. In order to provide a comprehensive analysis, the simulation outcomes will be compared with findings from existing academic and non-academic research such as the BZR 2. The results from the simulation will be critically assessed and the limitations and strengths will be highlighted.

Where the previous chapter has mainly focused on results as obtained from the simulation, the focus here is on highlighting what similarities occur when compared with other investigations and assessing aspects which have not been considered in the simulation of results. Consequently, this chapter will be dedicated to placing these results in a societal context and reasoning about the forthcoming implications for the energy transition as a whole.

6.1. Reflection and comparison

Since this research relies on various assumptions that have likely influenced the results, it is deemed valuable to compare the findings and most notable outcomes to existing investigations on the reconfiguration of the Dutch and German bidding zones.

The most extensive report on the reconfiguration of bidding zones in Europe is the previously described Bidding Zone Review 2 by ENTSO-E. This report encompasses both the Dutch and German reconfigurations investigated in this thesis as well as other configurations for Germany, such as splitting Germany in 4 and 5 bidding zones. Another valuable reference is the research conducted by TNO on the effects which the reconfigurations have on socio-economic welfare and CO_2 emissions (TNO, 2024). TNO assesses a Dutch bidding zone split similar to Split Scenario 1, as well as a 2-zone German configuration, similar to Split Scenario 2, and a 4-zone German reconfiguration, similar to DE4 as proposed by ACER (Figure 2.5).

An important metric which has previously been introduced is social welfare. While this thesis does not explicitly quantify social welfare (see Chapter 2), it is the central metric in both the BZR 2 and TNO assessments, forming the basis of their recommendations. In the BZR, social welfare is defined as economic efficiency, calculated by subtracting the change in additional redispatch costs from the change in consumer surplus, producer surplus, and congestion rents. TNO adopts a similar definition, assessing welfare gains as the reduction of redispatch costs relative to a base case in which these costs are already present.

The BZR 2 finds the highest positive net benefits (social welfare gains), €339 million in 2025, when splitting Germany into 5 bidding zones (ENTSO-E, 2025), a reconfiguration which is not assessed in this thesis. For the Dutch split, the BZR 2 finds net benefits of €9 million, a significantly lower result. TNO ultimately recommends both German splits as opposed to the status quo since DE2 yields €2.5 billion in net benefits and DE4 yields €4.5 billion in net benefits. Earlier in this thesis, the validity of results as posed by the BZR 2 has been discussed; one of the critiques involved the inclusion of cross-zonal redispatch in the welfare calculation. This same critique applies to the TNO report and the required results must be interpreted with this in mind.

Overall, the findings obtained in this thesis and those from TNO and the BZR 2 share important similarities and differences. All studies find that splitting Germany into a Northern and a Southern zone results in Germany-North emerging as a major electricity exporter. The South of Germany, on the other hand, becomes a significant electricity importer, facing higher electricity prices as a result, opposed to the North, which benefits from a large renewable energy base. Another consequence of the German North–South split is the occurrence of loop flows on the French–German border due to congestion on the Belgian–German interconnection. This is explicitly highlighted in both the BZR 2 and the analysis presented here. Additionally, decreased redispatch needs in the German split configurations are identified by TNO, the BZR 2, and the simulation results, indicating that splitting bidding zones indeed makes intrazonal congestion explicit. However, while reduced redispatch volumes are also reflected in the current simulations, differences in redispatch definitions between methodologies mean that direct comparisons may be misleading.

An interesting observation regarding the Dutch split is that both TNO and the BZR 2 report no significant price differences when splitting the Dutch bidding zone. The simulation results, however, find a significant price difference under such a split. The BZR 2 finds that splitting Germany would decrease electricity prices in the Netherlands by 2%. Both the BZR 2 and TNO do not include detailed statistics on prices, whereas this thesis identifies strongly increased volatility in the Netherlands-South, more stable prices in the North, and overall lower prices in the North while the South sees a price increase. This discrepancy may be due to the overall low amount of electricity exchange between the North and the South in the simulation result as a consequence of the limited intrazonal capacity. With respect to Dutch electricity flow, the South often exports to the North during negative price hours, whereas the North lacks the capacity to export more to the South. TNO similarly reports little export from the Netherlands-North to the South. An important observation is that TNO reports a 3% increase in interconnector capacity when splitting the Netherlands, mostly due to increased availability between the Netherlands and Germany. The simulations results similarly show more line utilization between the North of the Netherlands and Germany.

There is one particularly important aspect which has not been taken into account in this thesis, but must be carefully considered when assessing bidding zone reconfigurations, namely the transition costs. These are defined as “*one-off costs, expected to be incurred in case the BZ configuration is amended*” (Compass Lexecon, 2023). Such costs must be related to changes that are “*inherently and unambiguously related to a specific BZ configuration change*” (Compass Lexecon, 2023). It should be noted that Compass Lexecon themselves state that these estimates only capture part of the costs that will most likely arise. These costs cannot be seen as merely theoretical as in reality the costs will materialize and will have to be borne. According to the BZR 2, referencing Compass Lexecon (2023), the transition costs associated with splitting Germany are estimated to range between €1,250 and €2,250 million. These costs are highly relevant, as they directly affect the payback period of the estimated annual social welfare gains, calculated to fall between 4 and 9 years. While ENTSO-E stresses that the costs should be factored into any political decision on zonal reconfiguration, TNO characterizes the figures as ballpark estimates, explicitly noting that they are based on a ceteris paribus assumption, that is, the rest of the system remains unchanged, which from a research perspective may be understandable, but from a policymaking perspective is highly unrealistic.

This ceteris paribus approach is exactly what is challenged by the simulation results presented in this thesis. Rather than treating zonal outcomes in isolation, the analysis reveals how even seemingly small reconfigurations can lead to significant system-wide effects, both direct and indirect. A key insight is the extent to which interactions between zones shape price formation together with physical flows and redispatch needs.

This research demonstrates that by jointly considering all relevant market metrics, congestion metrics and distributional effect, it becomes possible to, not merely, observe what changes occur under different bidding zone configurations, but also to reason about why they occur. This integrated assessment enables a deeper understanding of the underlying mechanisms behind observed outcomes. For example, the emergence of loop flows through France, the price increase in Belgium, and the increase in redispatch needs in the Netherlands as a result of splitting Germany, they are all part of a broader pattern of interdependence shaped by structural bottlenecks, demand concentration, and constrained intrazonal capacity. This level of insight would be missed in a more isolated, one-dimensional evaluation. Analyses that treat redispatch costs or social welfare independently fail to capture the complexity of interactions that determine how electricity flows and prices evolve across interconnected systems. The holistic and interdependent perspective adopted here underscores that bidding zone configurations are not merely technical or isolated choices, they are decisions with far-reaching consequences.

6.2. Societal relevance and contribution

This thesis contributes to the ongoing debate on bidding zone reconfigurations, a discussion made highly relevant by the publication of Bidding Zone Review 2 (ENTSO-E, 2025), after which Member States have six months to decide whether and how to implement bidding zone reconfigurations (TenneT, 2025). Ambrosius et al. (2020) highlight that before market design changes materialize, there is often a preceding, long-lasting, period of uncertainty during which policymakers debate and have to decide on the, to be implemented, changes. The current six-month decision window therefore also exists within a broader environment of systemic complexity, political negotiation, and technical uncertainty.

Given this, the broader societal and systemic implications of reconfigurations must be taken seriously. Solely investigating the effects of bidding zone reconfigurations without commenting on the forthcoming implications of these results is deemed insufficient. This section aims to highlight that, although briefly discussed, the forthcoming societal implications, in the context of the energy transition, are ultimately what matters for society.

The distributional consequences observed in the simulations results for instance have direct societal impacts. Germany-North benefits from increased renewable exports and lower prices, whereas Germany-South becomes increasingly dependent on imports and faces persistently higher prices. This may particularly affect energy-intensive industrial clusters, such as those in the Ruhr area, which are vulnerable to increased electricity costs. In the Netherlands, the South becomes more volatile and congested, while the North experiences more stable conditions. These outcomes could influence household electricity bills, regional investment attractiveness, and even political support for future reforms. Southern Germany politicians and lobbying parties have already stated their objections to splitting Germany into multiple zones (CleanEnergyWire, 2025).

Additionally, the simulations revealed increased price volatility in certain regions, especially in the Netherlands-South, this volatility is likely a result of higher renewable energy penetration. While volatility may signal risk, it also presents opportunities, for example, by creating favorable conditions for investments in flexible assets such as storage or demand response. At the same time, persistently low or negative prices, particularly in Germany-North, may distort investment signals for renewable generators like offshore wind, which depend on stable revenues. These dynamics illustrate how zonal reconfiguration might influence investment strategies and long-term decarbonization plans.

TenneT (2025) has stated that they see no reason to proceed with a Dutch bidding zone split, substantiated by limited system-wide benefits and uncertainty regarding the practical implications. A German split, on the other hand, has shown significant potential in both the TNO and BZR 2 reports, yielding notable social welfare benefits and reductions in redispatch volumes. The simulation results in this thesis similarly support that conclusion: splitting Germany effectively internalizes structural congestion and reduces redispatch needs. On the other hand splitting the German electricity system again results in significant uncertainty regarding the effects on other bidding zones. As observed earlier, splitting Germany may cause increased redispatch needs in the Netherlands for instance.

Another important societal aspect regarding the decision to be made is associated with the transition costs. Transition costs for implementing a German split are estimated to range between €1,250 and €2,250 million (Compass Lexecon, 2023). In the context of the energy transition, where grid reinforcements, RES integration, and flexibility investments are already costly developments, the additional transition costs are even more relevant. Ultimately, the transition costs must be borne by someone, the costs for grid reinforcements are for instance often passed on to consumers through transmission tariffs. Renewable- or storage investment costs similarly may be borne by consumers through higher electricity bills. These mechanisms raise important questions of fairness and affordability, making the issue of who ultimately bears the cost a key concern in the broader energy transition.

The contribution of this thesis lies in connecting these technical results to the broader societal and strategic context. The aim is not to advocate for or against a bidding zone reconfiguration, but to highlight the far-reaching implications bidding zone reconfiguration can have, particularly within the framework of the European energy transition. This research shows that reconfigurations are not just technical choices made in isolation; they carry distributional consequences, operational complexities, and systemic risks that directly affect consumers, industries, and governments.

This thesis emphasizes the idea that market design decisions must be understood as part of an interconnected system. The simulation results underscore that what may appear to be a localized effect often originates from broader interdependencies and network-wide interactions. Without accounting for these dynamics, policy and regulatory decisions risk oversimplifying an inherently complex system. By assessing the reconfigurations through a multi-dimensional framework including congestion metrics, market efficiency metrics, and distributional effects this thesis offers a novel contribution to the bidding zone debate. It provides not only a method to assess the technical impacts of zonal splits but also the means to reason about their societal implications by investigating why effects take place. As such, it can serve as a valuable tool for policymakers, system operators, and regulators and ensure informed and forward-looking decision-making aligned with the goals of the energy transition.

6.3. Limitations

Several limitations must be acknowledged in relation to the design, data quality, and interpretability of the simulation results. First, the model does not include all bidding zones within the wider Central Western European (CWE) region. Notably, parts of the European electricity system such as the United Kingdom, Nordics, and Spain were not modelled in this thesis. The unmodelled zones, if they were modelled, may have affected flow patterns and congestion metrics.

A big limitation concerns the quality and granularity of the input data. Mainly the input data as obtained from the Static Grid Model shows multiple peculiarities and inconsistencies each with its respective effect on the model outcomes. To mitigate these effects, corrective measures were implemented, specifically capping thermal interconnection capacities and limiting line susceptances. The implemented measures have increased the adherence to reality of results and made them more accurate with respect to real data. Despite these improvements, the validity of our results in some scenarios cannot be presented with full confidence. As a result, there are several observed outcomes, especially regarding cross-zonal flows and border dynamics, for which no firm conclusions can be drawn. One of the main limitations stemming from this poor input data is the fact that we have not been able to comment with confidence on the intra- and interzonal flows within and concerning the Netherlands. Another limitation stems from the coarse spatial granularity of the modelled zones. As each bidding zone encompasses a relatively large geographical area, intrazonal dynamics, particularly those near zone borders, are not always accurately captured. This affects our ability to meaningfully analyze loop flows and localized congestion events.

Regarding the model, the proposed methodology, specifically the Exact Projection approach, was successfully implemented. This allowed the construction of a feasible set of nodal net positions that ensures no overload occurs on transmission lines. While the model did not achieve full convergence in every case, the resulting 'near-converged' outcomes were carefully monitored across all split scenarios. In each instance, residual imbalances and overloads were found to be negligible. As such, the use of near-converged results is not considered to have significantly affected the validity of the findings presented in this thesis.

Recommendations regarding the limitations

To address the identified limitations, several recommendations can be made. First, improving the quality and consistency of the input data, especially regarding grid topology would most likely significantly enhance the accuracy of simulations. Second, increasing the spatial granularity of modeled nodes in zones would allow for a more precise representation of intrazonal dynamics, especially near borders, enabling better analysis of loop flows and internal congestion. Expanding the model to also include non-CORE regions could also yield more accurate results although this comes with additional complexity in coupling flow-based and non flow-based regions. The HVDC interconnection between Germany and Belgium could explicitly be modelled which would most likely yield far more realistic results as opposed to reality.

While the Exact Projection method was chosen in this thesis for its feasibility within the available time-frame, alternative modeling approaches may offer more integrated solutions in the future. A promising direction is the method described by Wyrwoll et al. (2021), which combines Lagrangian Relaxation with Mixed Integer Linear Programming to integrate price determination and market coupling into a single optimization step.

7 Conclusion

This thesis has investigated the following research question:

How does the reconfiguration of the Dutch and German bidding zones within a flow-based coupled market impact system-wide market efficiency, congestion, and distributional effects?

A central insight is that bidding zone reconfigurations do not operate in isolation. Even seemingly small changes trigger complex effects that propagate far beyond national borders. The outcomes do not emerge in a predictable fashion, but rather arise from the interplay between network topology, market coupling mechanisms, the spatial distribution of demand and supply, and a host of structural, operational, and other systemic factors. These interactions result in emergent system-wide behaviour, such as price divergence, loop flows and redispatch shifts that cannot be explained through localized assessments alone. It is precisely this complexity that underscores the need for a multi-dimensional, cross-zonal evaluation framework that reflects the interconnected nature of the European electricity market.

From a market efficiency perspective, splitting a bidding zone can enhance efficiency by allowing electricity prices to better reflect actual congestion and system conditions, particularly through their impact on price volatility and the frequency of extreme price events. These indicators, heavily influenced by the spatial distribution of renewable generation, provide insight into the flexibility and stability of the market under different zonal structures. In the simulations, Germany-North, which is characterized by a significant amount of renewable generation, exhibits a substantial increase in hours with negative prices. Similarly, the Netherlands-South, with constrained transmission capacity and increased exposure to renewable fluctuations, sees elevated price volatility and a high frequency of extreme price events. The investigation similarly shows that increased interconnection capacity utilization between zones results in an overall mediating effect with respect to price volatility and the frequency of extreme price events. Ultimately, market efficiency metrics offer important insights into how the system allocates resources, but they do not provide a complete representation of overall system performance. This also depends on how effectively new zones reflect underlying grid constraints, transmission capacity limitations, and the physical distribution of generation and demand. Congestion metrics such as redispatch volumes and congestion are essential to complement the assessment.

Congestion is highly dependent on system interactions and the interdependence between zones. Splitting zones exposes effects that were previously internalized, allowing congestion to become visible and measurable rather than being masked by a single zonal price. The simulations demonstrate that while splitting Germany significantly reduces internal redispatch volumes, by making the structural North–South bottleneck explicit, this benefit is not observed across the system as a whole. In fact, redispatch volumes in the Netherlands increase significantly as a consequence of the German split. Splitting the Netherlands itself consequently does not alleviate these internal bottlenecks. This underscores the conclusion that intrazonal transmission capacity in both the Netherlands North and -South is insufficient to accommodate renewable generation variability and local demand concentrations. As a result, the degree of interaction between the Netherlands and neighboring zones remains relatively limited, even under a zonal split. In contrast, splitting Germany leads to significant changes in cross-border flow patterns and interzonal dependencies. A clear example is the emergence of loop flows from Belgium to Germany via France, driven by high demand concentrations in southern Germany near the Belgian border. This illustrates how the effects of reconfiguring a central bidding zone extend beyond the zone itself, reshaping the behaviour, interactions, and dependencies across the entire interconnected system. A consequent effect of these shifts is the redistribution of benefits and losses across zones, as changing roles within the system alter who exports, who imports, and at what price.

The distributional consequences of bidding zone reconfiguration become particularly clear when examining the changes in zonal price levels and net positions. In the German split scenario, Germany-North emerges as a large net exporter with consistently low electricity prices, driven by its high concentration of renewable generation and relatively low demand. In contrast, Germany-South becomes increasingly dependent on imports and faces persistently elevated prices due to higher demand and limited local generation capacity. In the Netherlands, the effects are more nuanced. The North sees higher average prices than before, in part due to limited local demand and more expensive generation sources. Meanwhile, the South, despite being more volatile and congested, does not significantly increase its interzonal interaction, further suggesting that internal capacity constraints continue to limit flexibility. The distributional effects of reconfiguration are not limited to the zones being split, they are felt across the entire system. For example, in response to increased demand in Germany-South, Belgium becomes a major exporter, despite previously being a net importer, experiencing steeply increased prices as a result. Poland, on the other hand, benefits from the surplus of renewable energy in Germany-North with consequent lower prices. These outcomes underscore once more that bidding zone reconfiguration reshapes roles, relationships, and flows across the entire European electricity market.

At the time of writing, EU Member States are in the midst of a critical decision window, with only a few months remaining to determine whether and how to implement bidding zone reconfigurations. These decisions must be situated within the broader context of the European energy transition, coinciding with developments such as renewable energy integration, grid expansion, and evolving market designs. Together, these trends will fundamentally reshape the design of the European power system in the coming decades. In this light, splitting countries like Germany and the Netherlands is a complex intervention with far-reaching, system-wide consequences. Without accounting for the interactions and interdependencies, policy and regulatory decisions risk oversimplifying an inherently complex system.

Ultimately, what this thesis demonstrates is that bidding zone reconfigurations are positioned within a deeply interconnected system. Their impacts cannot be adequately captured by a single metric, whether related to congestion, market efficiency, or distributional effects. By incorporating interactions, interdependencies, and cross-zonal dynamics, this research presents a robust, multi-dimensional assessment that captures the full system-wide perspective. In doing so, it provides policymakers, regulators, and system operators with the tools needed to make informed decisions that are aligned with the goals of the sustainable energy transition.

7.1. Personal Reflection

When I started this thesis, I had very limited knowledge of the topic. I didn't know what flow-based market coupling (FBMC) was, and I didn't expect to dive so deeply into the technical complexities of European electricity markets. As I progressed, I quickly realized how complex the subject is, that complexity is however also what made it so interesting. Exploring a topic that I initially knew very little about, and gradually building enough understanding to simulate and analyze realistic scenarios, has been both challenging and rewarding.

From a technical perspective, I also began with no experience in the programming language used in the model. Learning how to work with it, alongside all the modelling concepts, was a steep learning curve, but ultimately a valuable experience. This is not necessarily a path I would recommend anyone starting their thesis, as I think at least having a bit of prior knowledge of a programming language before modelling with it, is quite valuable for a thesis. In the end it gave me hands-on insight into how energy market models are structured, how much data is necessary to even run the model, and I found it a good challenge to overcome, proving to myself that this would not get in the way of starting the project.

Initially, the relevance of this research to KYOS was defined as understanding how flow-based market coupling might affect results, and whether incorporating such a mechanism into their current model could yield more accurate insights. The model used in this thesis originally had no spatial reconstruction or physical topology incorporated. The coupling of such an originally purely price-based model to a spatial reconstruction constructed outside of the model proved to be a significant challenge but an interesting and fun one to overcome.

As the results and validation indicate, I believe that with improved input data and further refinement, this type of modelling could become increasingly valuable to KYOS. A deeper comparison between their current model and the constructed FBMC-based model could also provide new insights that have previously been overlooked.

7.2. Recommendations for Future Research and Academic Reflection

The original knowledge gap lies in the absence of a system-wide perspective in existing research on bidding zone configurations. While various technical and economic aspects have been studied in detail, the broader picture, how changes in one part of the system interact with and influence outcomes in others, has often been neglected. As shown throughout this thesis, interactions and interdependencies matter. They are not just background complexity; they fundamentally shape who benefits, who bears the costs, and how the electricity system performs overall. This aligns with ENTSO-E's own acknowledgment in the Bidding Zone Review 2 that conclusions drawn in isolation, especially from simulations alone, are insufficient for robust decision-making. The CoSEM perspective reinforces this: without understanding the dynamic relationships within the system, policy choices risk being misguided.

This thesis addresses the gap by applying a system-level lens to the analysis of bidding zone reconfiguration. It shows that changes in zonal structure do not happen in isolation, congestion patterns, price dynamics, redispatch needs, and welfare effects are all closely connected. For example, a shift in one region's boundaries can significantly affect flows, prices, and emissions in others. These findings underscore that isolated evaluations miss the very effects that matter most when it comes to the real-world implications of such reforms.

At the same time, limitations must be acknowledged. In particular, data quality and spatial granularity constrained the analysis. The power flow results did not yield the depth of insight initially expected, and as such, intra- and interzonal effects could not be interpreted with complete certainty. Despite the limitations, the work serves as a starting point, demonstrating the value of embedding bidding zone assessments within a broader framework that captures system-wide effects and cross-border interactions. The CoSEM perspective in this sense has contributed to partly fulfilling the research gap.

Future research can build on this foundation and investigate in greater depth how reconfiguration affects specific aspects of the electricity system while still taking in regard a system-wide perspective. For instance, understanding how zone changes influence renewable energy integration or grid reinforcement could yield valuable insights. Social and political dimensions could also be explored more explicitly: how national interests, fairness perceptions, and public acceptance shape the feasibility of different zonal scenarios. The role of flexibility measures such as demand-side response and energy storage could be explored more thoroughly, particularly how their deployment and operation are affected by zonal layouts and congestion patterns. Finally, institutional and governance challenges would be an interesting research direction, including how regulatory coordination and uncertainty across borders influence the design and reconfiguration of bidding zones.

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A

Modelling Workflow

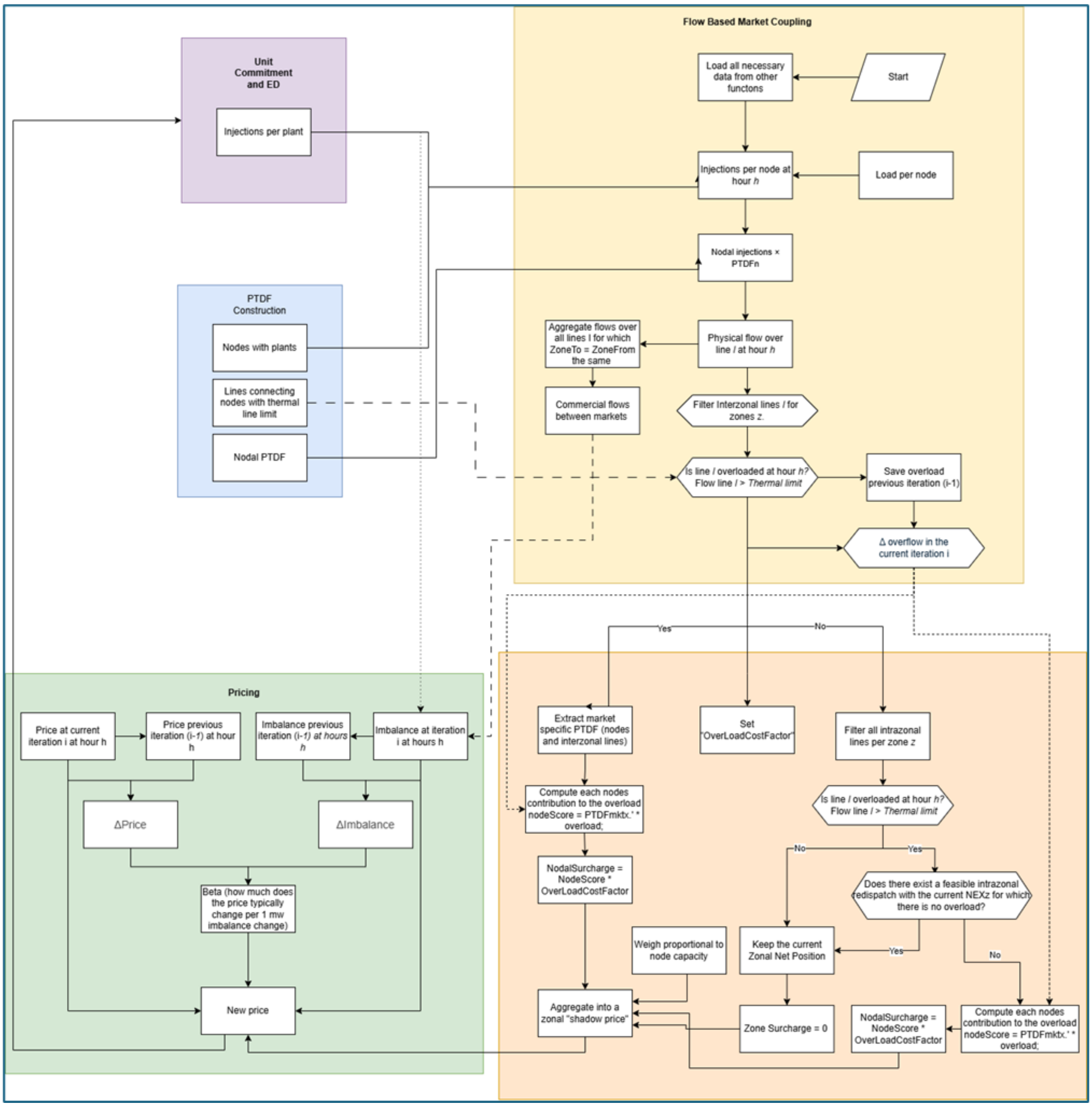

Figure A.1: Exact Projection Model Implementation, the blocks shown over the course of the model explanation are all shown together in order to show how they work together.

B

DC Power Flow

The DC power flow equations are a linearization of the more complex AC power flow equations which can be justified by the following three assumptions (Purchala et al., 2005):

1. **No line resistances:** the transmission network is assumed to be lossless, meaning only line reactances are considered. Out of which follows:

$$B_L = \frac{1}{X_L} \tag{7.1}$$

   Where:

   - B_L = Susceptance of line L
   - X_L = Reactance of line L

2. **Small voltage angle differences:** the differences between voltage phase angles at connected buses are assumed to be small enough that the sine function in the AC power flow equation:

$$\sin(\delta_N - \delta_Q) \approx \delta_N - \delta_Q \tag{7.2}$$

3. **Flat voltage magnitudes:** nodal voltage magnitudes at all buses are assumed to be equal to 1 per unit.

The following equation for the PTDF-matrix, based on Van den Bergh et al. (2014), can then be derived:

$$\text{PTDF}^{L\times N} = (B_d \cdot A) \cdot \left(A^T \cdot B_d \cdot A\right)^{-1} \tag{7.3}$$

Where:

- B_d = Diagonal matrix of line susceptances
- A = Incidence matrix

The matrix $\left(A^T \cdot B_d \cdot A\right)$ in equation (7.3) is singular, meaning that it cannot be inversed, this is due to the linear dependence of the equation. This problem can be tackled by appointing one node (bus) the slack node. This bus acts as a fixed point for voltage angles and allows the system to have a unique solution (Van den Bergh et al., 2014). For the complete set of equations the reader is referred to Van den Bergh et al. (2014).

What we are concerned with here are the assumptions and implications of the assumptions of using DC Power Flow.

In reality, TSOs construct PTDF matrices for each hour of the day and incorporate N-1 security constraints. N-1 refers to the failure of any single component in the network, a contingency, which would consequently alter the PTDF-values (Schönheit et al., 2021). We exclude these contingencies in our model to reduce computational complexity.

The earlier mentioned assumptions result in a linear relationship between nodal injections and line flows, and allow the PTDF matrix to be calculated using the line susceptance matrix and network incidence matrix (Appendix B).

The DC power flow approach has proven to be a good approximation of power flow in transmission networks and suitable for techno-economic analysis (Purchala et al., 2005; Van den Bergh et al., 2014). The error on individual transmission lines, however, can be significant, and this should be taken into regard when assessing the network performance (Purchala et al., 2005).

Given that our scope is limited to the CORE region, the obtained PTDF matrix through this methodology will have the following layout:

CNE↓	AT1	AT..	DE1	DE..	NL1	NL..	BE1	BE..	FR1	FR..	SL1
line 1	PTDF$_{1,AT}$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$
line 2	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$
$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$	$\vdots$
line n	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	$\dots$	PTDF$_{n,SK}$

Table B.1: PTDF Matrix CORE Region example

Where the columns represent the nodes in which electricity is injected or consumed and the lines represent the lines in between the nodes. The value within a cell will then be the linear relationship between an injection in a node and the effect on that specific line.

C

Generation Mix Visualized

Figure C.1: Generation Mix Visualization, the visualization is shown as addition to the MAE in Chapter 4.

D

Model Parametrization & Assumptions

In this section we investigate the effect of modelling choices which were made and the extent to which the model is sensitive to the input data. This is necessary both to improve the model's realism and to understand the sensitivity of outcomes to different model configurations. Here, "model configuration" does not refer to changes in the underlying model behavior or logic, but to adjustments to the assumptions and input parameters described in Section 4.7 (*Conclusion on Model Parametrization*). The key assumptions we analyze are regarding the line susceptances, thermal line limits and minimum price threshold. In the model testing phase it has been noticed that the model is sensitive to changes in these inputs. We introduce this section to show the validity of the assumptions and to ultimately reach a configuration of assumptions that reflects real-world outcomes as accurately as possible. The testing phase was based on April 2025.

D.0.1. Line Susceptances

As previously described, line susceptances in the model are derived from the input data of the Static Grid Model. This means that if the input data is inaccurate, the resulting flows can be unrealistic. For example, on the Belgium–Germany border, the static grid model contains a line with a susceptance of 20 Siemens a value 1000% higher than many other lines in the SGM. There are about 60 other instances of this, mostly intrazonal lines in Germany and the Netherlands. To assess the sensitivity of model outcomes to these extreme susceptance values and thermal line limits, we compare flows under various configurations, one with unaltered susceptance values, one with capped susceptances and thermal line limits.

It is important to note that altering the susceptance of a single line affects the PTDF values of all lines, as the PTDF calculation preserves a globally consistent distribution of power flows, in other words, if a flow is not distributed over one line it will over another. Therefore, when applying a cap, we choose a sufficiently high threshold to preserve the fact that certain lines originally attracted disproportionately high flows, while avoiding unrealistic magnitudes (e.g. flows as in figure D.3). Figure D.4 shows the flows over the Belgium-Germany border with susceptances capped at 2 Siemens and thermal line limits enforces. The figure still shows flow peaks as is expected, however the magnitude of those peaks is significantly reduced and within range of the Belgium-Germany available interconnection capacity.

D.0.2. Interconnection Capacities

In the initial version of the model the thermal line limits obtained from the Static Grid Model were observed to be for each bidding zone pair almost twice as high as in reality.

Figure D.1 shows the initial comparison between the ENTSO-E reference grid (Ember, 2024) and the values obtained through the Static Grid Model. Column "SGM" shows the interconnection capacity as obtained from the Static Grid Model.

Country From	Country To	Reference grid ENTSO-E (MW)	SGM (MW)
Netherlands	Germany	5000	13611
Czech	Germany	4200	10388
Austria	Germany	5400	10239
Belgium	France	4300	8474
Netherlands	Belgium	3400	8218
Germany	France	3300	7350
Austria	Czech	900	6821
Poland	Germany	3000	6634
Austria	Hungary	800	5917
Slovakia	Hungary	2600	5002
Hungary	Croatia	1700	3844
Slovenia	Croatia	2000	3765
Poland	Czech	1400	3440
Czech	Slovakia	1800	2698
Poland	Slovakia	1980	2633
Hungary	Slovenia	1200	2595
Austria	Slovenia	950	2527
Belgium	Germany	1000	2369
Hungary	Romania	1100	2369

Figure D.1: ENTSO-E Interconnection capacities.

Originally the thermal line limits were scaled to 50% of the capacities as obtained from the SGM. This yielded line limits which were sometimes a bit over – and sometimes a bit under the thermal line capacity as reported by ENTSO-E. Therefore it was decided to, for interzonal lines, adopt the capacities as reported by ENTSO-E which can be found above. For intrazonal lines, where ENTSO-E does not report any values, we stick with the 50% assumption as on intrazonal lines the slight mismatch in over/under capacity is off less importance as long as the total capacity remains consistent.

It is important to note that the choice of thermal line limits does not directly affect the physical flow computations themselves, which are always based on full physical flows derived from the PTDF matrix. However, the thermal limits do serve as the activation threshold for the congestion pricing mechanism in the model: they determine when a line is considered ”congested” and when the corresponding overload penalties become active. Therefore, setting appropriate and realistic thresholds is important for ensuring that the congestion pricing signals are triggered at moments corresponding with realistic values.

D.0.3. Minimum Price Threshold

In this section a brief sensitivity analysis is performed. The minimum price threshold in the model is varied from -100, -75, -50, -25 and the effect on the corresponding zonal prices in NL, DE, BE, FR and PL is investigated.

The results are displayed in Table D.1 and show notable price differences when varying the minimum price threshold. The most noticeable effects occur in the zones with the highest levels of installed renewable capacity. This is expected, as large shares of renewables tend to drive market prices downward. Figure D.2 shows the share of energy from renewables in gross electricity consumption across the EU. We observe that Germany has the highest share among the countries shown, followed by the Netherlands and Belgium. France’s renewable share is lower, but its market is somewhat insulated from price volatility due to a large and stable share of nuclear generation. Poland, on the other hand, shows the lowest renewable share, resulting in relatively muted price responses to the threshold changes.

Germany in this case is the biggest benefiting party with prices going from 40.27 €/MWh at a threshold of -100€/MWh to 54.37€/MWh at a threshold of -25€/MWh. The effect in the Netherlands is similarly very noticeable, in Belgium it is limited and in Poland and France it is negligible. Overall zones with a high amount of installed renewable capacity benefit in terms of reduced prices when the minimum price threshold is lowered.

Table D.1: Effect of Curtailment Price Thresholds on Mean Output per Country. The mean represents model outcomes at different price thresholds; △Mean reflects sensitivity to tightening curtailment levels. All values are in €/MWh

Country	Threshold	Mean	Std Dev	Min	Max	△Mean
NL	–25	92.35	63.22	–25.00	269.49	–
	–50	89.89	67.80	–50.00	267.69	–2.46
	–75	87.72	72.53	–75.00	270.14	–2.17
	–100	86.03	76.49	–100.00	270.29	–1.69
DE	–25	54.37	59.54	–25.00	208.08	–
	–50	48.65	67.24	–50.00	203.98	–5.72
	–75	44.86	73.73	–75.00	205.30	–3.79
	–100	40.27	80.30	–100.00	210.20	–4.59
BE	–25	75.08	60.72	–25.00	200.17	–
	–50	73.13	64.75	–50.00	199.81	–1.95
	–75	72.32	67.40	–75.00	199.74	–0.81
	–100	71.89	68.78	–100.00	199.72	–0.43
FR	–25	34.82	12.92	–24.71	151.55	–
	–50	34.84	13.30	–38.67	150.48	+0.02
	–75	34.87	13.34	–38.61	150.35	+0.03
	–100	34.82	13.34	–38.61	149.94	–0.05
PL	–25	109.70	15.97	24.25	142.54	–
	–50	109.75	16.05	24.12	142.83	+0.05
	–75	109.69	16.01	24.11	142.64	–0.06
	–100	109.72	16.03	24.11	142.87	+0.03

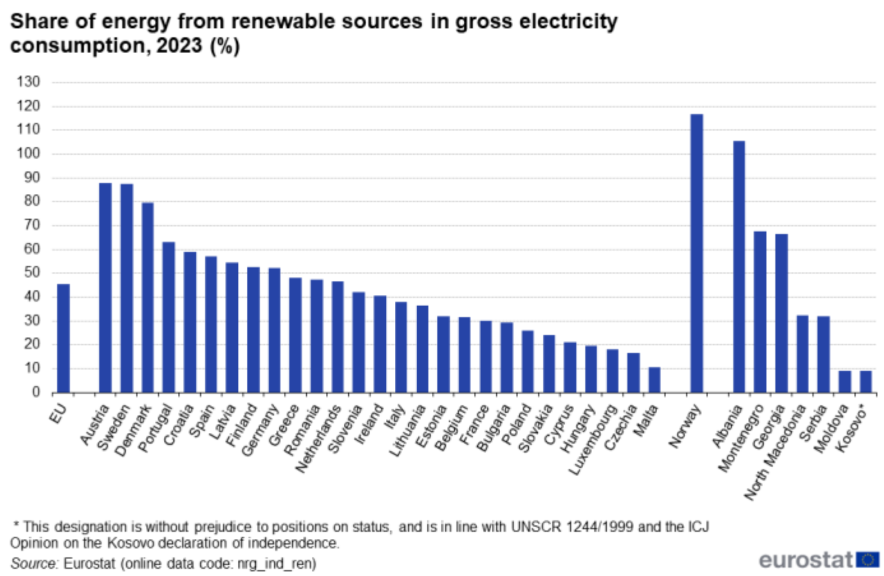

Figure D.2: Eurostat, (2023) *Share of energy from renewable sources in gross electricity consumption, 2023.*

D.0.4. Conclusion on model parametrization

During the testing phase of the model we've tested several configurations, among these where the following:

- Susceptances uncapped / interconnection capacity enforced
- Susceptances uncapped / interconnection capacity enforced
- Susceptances uncapped / interconnection capacity unenforced
- Susceptances capped / interconnection capacity unenforced

The Mean Absolute Error and model behaviour was in all of these configurations investigated and observed to "behave" and perform (against real data) best under the configuration "susceptance capped (at 2) and interconnection capacity enforced. The value 2 was chosen as it is relatively still a 'high' value but not excessively high. It thus preserved the fact that these transmission lines originally were attributed a large portion of flow but not so excessive as to distort model behaviour.

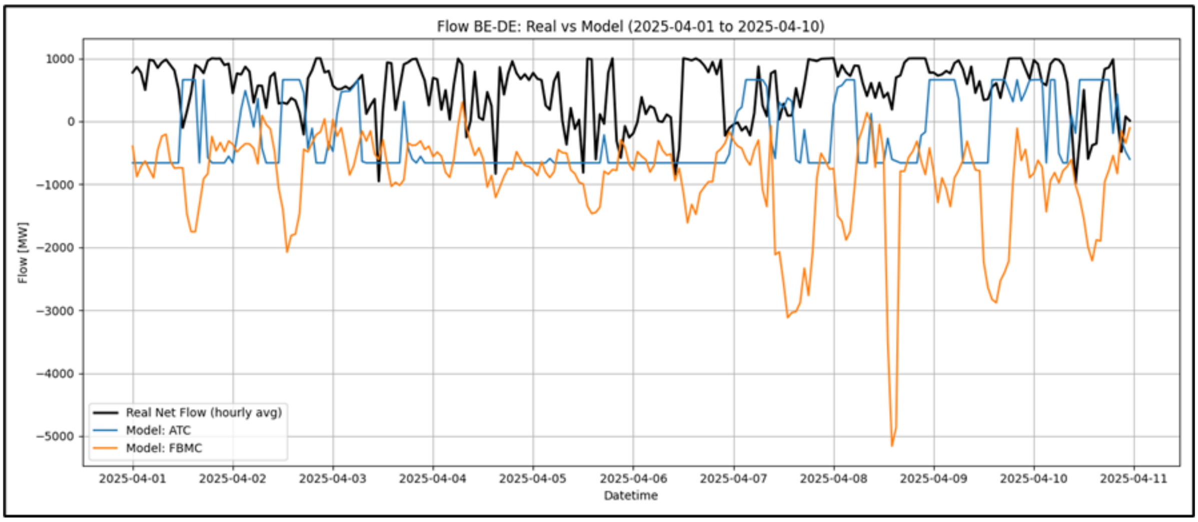

Figure D.3: Flow from BE-DE when no thermal limit capping is applied. Flows may significantly exceed interconnection capacities (1GW in this case)

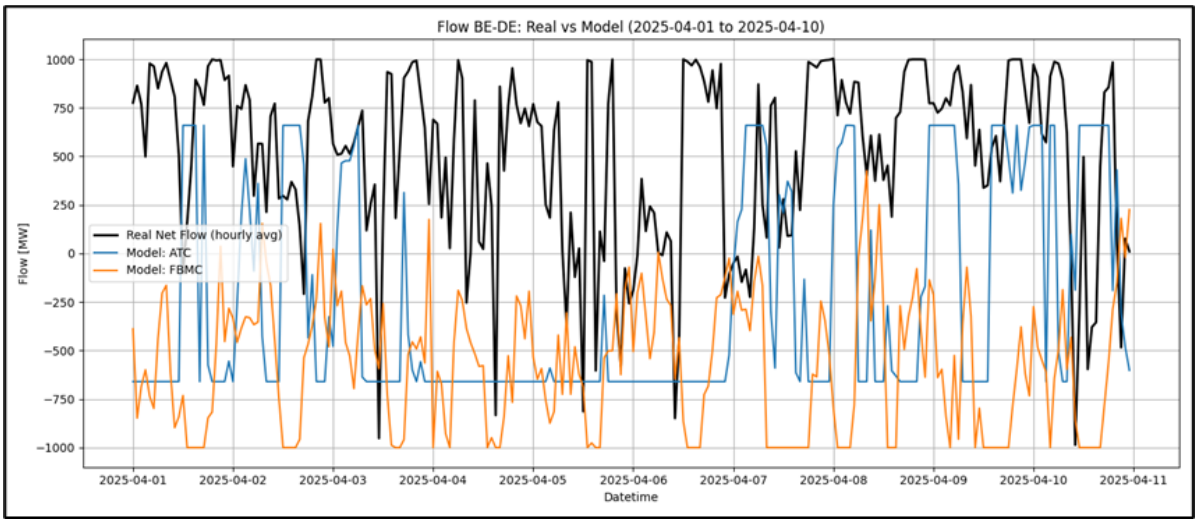

Figure D.4: Flow BE-DE with susceptance capped at 2 Siemens and enforced thermal line limits, flows are way more realistic in this case.

E

ENTSO-E Interonnection Capacities

Initial comparison between the ENTSO-E reference grid (Ember, 2024) and the values obtained through the Static Grid Model. Column "SGM" shows the interconnection capacity as obtained from the Static Grid Model.

Country From	Country To	Reference grid ENTSO-E (MW)	SGM (MW)
Netherlands	Germany	5000	13611
Czech	Germany	4200	10388
Austria	Germany	5400	10239
Belgium	France	4300	8474
Netherlands	Belgium	3400	8218
Germany	France	3300	7350
Austria	Czech	900	6821
Poland	Germany	3000	6634
Austria	Hungary	800	5917
Slovakia	Hungary	2600	5002
Hungary	Croatia	1700	3844
Slovenia	Croatia	2000	3765
Poland	Czech	1400	3440
Czech	Slovakia	1800	2698
Poland	Slovakia	1980	2633
Hungary	Slovenia	1200	2595
Austria	Slovenia	950	2527
Belgium	Germany	1000	2369
Hungary	Romania	1100	2369

Figure E.1: Initial obtained Interconnection Capacities from the SGM