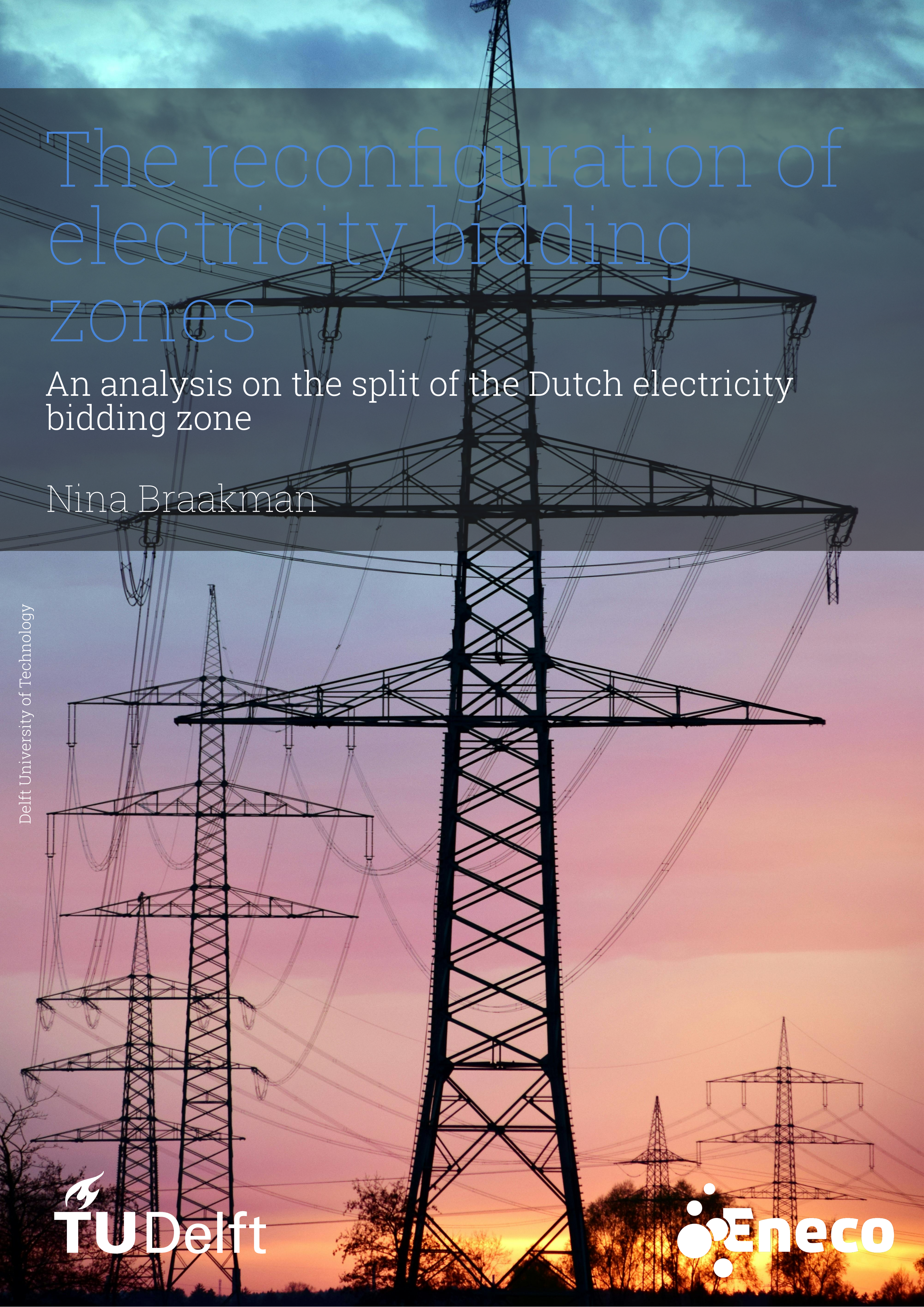

The reconfiguration of electricity bidding zones

An analysis on the split of the Dutch electricity bidding zone

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Delft University of Technology

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by

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in partial fulfillment of the requirements for the degree of

Master of Science in Complex System Engineering And Management
at the Faculty of Technology, Policy and Management

at the Delft University of Technology
to be defended publicly on Friday September 27, 2024.

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Project Duration:	Feb, 2024 - Sep, 2024
Faculty:	Faculty of Technology, Policy and Management, Delft

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This version is slightly edited by leaving out sensitive figures and tables.
Title page picture sourced from:
https://www.pexels.com/nl-nl/foto/zwarte-elektrische-toren-onder-blauwe-hemel-414967/

Acknowledgement

In this section, I would like to take a moment to thank everyone involved in my master's thesis research. First, I would like to thank my first supervisor, Kenneth Bruninx. Thank you for your constructive criticism. Our meetings in which we brainstormed about new ideas, and you helped me to get to the bottom of specific topics, were very useful. You helped me understand complex electricity market concepts and processes thoroughly and were always patient in explaining difficulties in depth when needed. Secondly, I would like to thank Dioni Franken, my external supervisor from Eneco. Thank you for your enthusiasm and ideas on this topic, and your supervision and support at Eneco. I also want to thank the whole SPM team for their guidance and ideas and for the chance to let me take a glimpse at their interesting work. Furthermore, I would also like to thank Julian Visser from the FA team for answering my questions on the modeling side and letting me collaborate on the model his team has created. Lastly, I would like to thank the rest of my committee. Thanks to Kamaldeen Adekola for assisting during my meetings with Kenneth and helping me review previous modeling work. Also, thanks to Aad Correljé, my second supervisor, for your critiques during the official meetings of my thesis process. Your comments helped me see the bigger picture and give my thesis a broader perspective.

On a personal note, I also want to thank my family and friends for their support during the last few months. A large thank you to my parents who have supported me during this challenging period and during the rest of my studies at TU Delft. Thank you for believing in me and showing a genuine interest in my process. Moreover, I would like to thank my friends who were also busy with their master's thesis during the same period and with whom I could have coffee and motivational talks during times of distress or setbacks that we were facing. Furthermore, I would like to thank my other friends who supported me in whatever way and reassured me that they had also gone through the same process and succeeded. Lastly, thank you to my boyfriend Joost, for being an emotional and intellectual support. Thank you for listening to my first ideas and proofreading my final work. Thanks also for cheering me up and encouraging me during this whole process. This thesis marks the end of my study period at TU Delft. This journey has taught me the value of perseverance and provided me with deep insights into fascinating energy and technology topics.

Executive summary

The Dutch electricity grid is facing significant pressure due to increased intermittent renewable energy generation, advancements in electrification and the rise of major electricity users. Transmission capacity has already reached its limit in several regions in the Netherlands. This leads to network congestion, which delays sustainable development in the energy sector and creates an unnecessary rise of electricity prices. Congestion problems exist in multiple EU countries. ACER has proposed the split of several electricity bidding zones in the EU as a solution to mitigate grid congestion. One of these proposed splits is the separation of the electricity bidding zone of the Netherlands into two bidding zones: a northern and a southern bidding zone. This split will separate the northern provinces of Friesland, Groningen, Drenthe and Overijssel from the other provinces in the Netherlands. Splitting large bidding zones into smaller zones could improve market efficiency by providing more accurate price signals. This will theoretically also lead to less congestion in the long term. While research has been conducted on the proposed split of the bidding zone split in Germany, research about a split in the Netherlands and its effects on the Dutch electricity market is lacking. Therefore, this thesis has investigated the following research question: *"How will splitting the electricity bidding zone in the Netherlands impact commercial cross-border exchanges and electricity prices in the Day-Ahead market in the Netherlands and its neighboring countries, and what risks does this split cause for energy companies?"*

To answer this question, a literature review was performed on the bidding zone split of Germany and Austria in 2018, which shows similarities to the proposed Dutch bidding zone split. Furthermore, a model was created with Plexos optimization software to do a nodal analysis of the Netherlands before the split, as well as a scenario analysis of the Netherlands before and after the split. These analyses used a backcast of September 2022 until December 2022. Lastly, the risks for energy companies due to the split were identified. These are the key findings of the research:

1. The neighboring zones next to Germany and Austria suffered from unscheduled flows from Germany. These unscheduled flows form a problem for the Dutch electricity grid as well. The DE-AT split reduced these unscheduled flows but did not achieve all desired effects concerning congestion resolution because of the remaining internal congestion in the German electricity system. The same may be true for the Netherlands and its proposed split.

2. Austria experienced higher electricity prices post-split. Similar consequences are expected of the Netherlands, where the south of the Netherlands will experience higher electricity prices. The north of the Netherlands, which has a relatively low demand and high renewable capacity, will experience reduced prices.

3. The reduction of market liquidity in Austria after the split was only found in long-term contracts, and can be resolved by adapting the terms of these contracts.

4. Nodal prices in the Netherlands in the evaluated period resulted in a distribution of two price groups: high-priced nodes in the west and low-priced nodes in the east of the Netherlands. This difference in nodal prices can be explained by three reasons: the load density in the west, congestion patterns in the high-priced areas, and the geographical positions of fossil power plants.

5. The scenario analysis, which varied inter-zonal commercial transmission capacity between the new Dutch zones and its neighboring zones, found some interesting results. It was observed that an available transmission capacity of 30% or below creates a significant price difference between the northern and southern NL zone, while above 50% prices converged. In the scenarios with low available transmission capacity, the northern NL zones reached prices of 0€/MWh. The scenario that is the closest to the predicted after-split situation has price differences between the northern and southern zones. An experiment was executed to investigate the effect of the split

on large electricity users, e.g. a large zinc factory with a capacity of 150 MW. In the investigated 4 months, the factory would pay 1.4M€ more for electricity in the southern zone than in the northern zone.

6. Due to the possible price differences in the NL zones, energy companies face risks. It is advised that the current state of their asset portfolio should be assessed based on the location of contracted or owned electricity supply and the location of consumers. By investing in new generation projects in the southern zone, energy generation companies can potentially increase their profits due to the increased electricity prices in the southern zone after the split.

7. Other developments in the electricity sector have been evaluated. A German split may result in the reduction of loop flows affecting the Dutch electricity system. This reduction could enlarge the commercial transmission capacity between the Netherlands and its neighboring zones, as well as between the new NL zones. This may result in more price convergence between the new zones. Furthermore, developments in the expansion of offshore wind capacity, possible offshore bidding zones, further grid expansion, and the growth of electricity demand will all influence the advantages or disadvantages of the bidding zone split. These developments, in combination with the large differences between nodal electricity prices and nodal demand found in the nodal analysis, suggest that a nodal pricing system may be a better solution for the Dutch and German bidding zones.

The modeling used in this research has some limitations. The modeling is an expansion of an optimization model in Plexos provided by Eneco. This model will be called the reference model. The available transmission capacity in the reference model is defined by the total thermal limit of a line. Implementing FBMC and NTC capacity calculation instead of total thermal limits improved the reference model by assessing the model's mean absolute error (MAE) compared to historical data. They were improved for the modeled CORE countries. This means that the backcast model still deviates from historical data. Predicted data after the split may have this same deviation. The model methodology causes another limitation. The scenario analysis does not precisely capture the consequences of the split on the inter-zonal transmission capacity and the new day-ahead prices but only provides possible scenarios that give an understanding of the consequences of this split.

Further research is needed to provide a more exact calculation of the new commercial transmission capacity between the new NL zones and to include the bidding zone split in Germany to capture the full extent of changes in the Dutch bidding zone split. Lastly, a congestion analysis before and after the split can show policymakers and grid operators if congestion has improved and whether a bidding zone split in the Netherlands is worth it.

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1 Introduction

1.1. Context

Network operators in the Netherlands face challenges in managing the increasing pressure on the electricity grid. The need for transmission capacity has grown significantly due to several developments. These developments are the increase in renewable energy generation, the advancement of electrification, and the rise in major electricity users. These three developments put additional pressure on the electricity grid. This makes congestion management increasingly important. Unfortunately, the Dutch electricity grid's transmission capacity is insufficient to meet these increasing needs. In several regions in the Netherlands, the maximum capacity has already been reached (Algemene Rekenkamer, 2022). Grid expansion needs to be realized faster. A congested grid can have quite some disadvantages. For example, it can lead to the curtailment of cheap renewable electricity. This causes unnecessary higher electricity prices. Another problem is that companies may be forced to delay their sustainable development initiatives or leave new housing projects unconnected to the grid. More pressure on the grid may also lead to higher re-dispatching costs. Network congestion is an obstacle the Dutch government must overcome if it wants to proceed with its planned sustainable development in the energy sector.

Electricity is traded in electricity markets with their respective rules and restrictions. These markets provide an efficient way to allocate electricity production to demanding parties. In these electricity markets, electricity is traded by market participants within and between bidding zones. To clarify, “A bidding zone is the largest geographical area within which market participants are able to exchange energy without capacity allocation” (Ofgem, 2014, p.1). In other words, electricity generated anywhere in a bidding zone can be traded freely within this zone without any transmission restrictions. In reality, these transmission constraints exist and are dealt with by re-dispatching the electricity. When trading between two different bidding zones, transmission is limited and regulated. A specific maximum transmission capacity restricts the maximum transmission capacity available for trade. This transmission capacity is restricted because of physical transmission limits between interconnecting transmission cables but also due to the electricity in the internal lines of these respective zones. To regulate the inter-zonal exchange, capacity allocation is needed.

The Netherlands uses one electricity bidding zone. The borders of this bidding zone coincide with the country's geographical boundaries. Most electricity bidding zones in Europe coincide with the geographical boundaries of its countries. However, some countries choose to use multiple bidding zones. Multiple zones in one country can be beneficial because of geographical characteristics or the concentration of specific energy sources. Aside from this, some bidding zones contain multiple countries. The configuration of these bidding zones in the European Union (EU) has changed over time. In the past, bidding zones have been split or have been merged. For example, Sweden was split into four bidding zones in 2011, and Italy was divided into six zones in 2006 (Bemš et al., 2016). Germany, Austria and Luxembourg were made into a collective bidding zone in 2005 (Szabó, 2017), until separating again into a German-Luxembourgian and an Austrian zone in 2018.

One main reason for splitting a bidding zone is to improve market efficiency. Reorganizing a zone into two or multiple zones will result in a more efficient electricity market and mitigate network congestion. The smaller an electricity zone, the more accurate the price signal. A large electricity zone combines the price behavior of different areas. Zonal pricing may not accurately reflect price differentiation. Another way to price electricity is on a nodal level. This method establishes the Locational Marginal Price (LMP) for every node. This price is based on the generators and demand that are closer to a node and on the imported and exported electricity possible in this node. Nodes with high renewable production will generally have a lower price than nodes with mainly fossil production. Transmission capacity between these nodes and the demand in the nodes also still plays a role. Nodes with a low electricity price attract consumers, such as companies with a high electricity demand. They are stimulated to locate their factories in these low-price areas. In turn, nodes with high electricity prices or electricity scarcity motivate parties to develop additional generation in this location. Nodal pricing includes generation and transmission costs at its most accurate representation and is the theoretically preferred approach (Plancke et al., 2016). The price signaling is more aligned with the physical properties of the grid. Lété et al. (2022) find a significant difference in efficiency when comparing nodal and zonal market designs in the long term, where the nodal market stands out. This is because local revenue is allocated better, resulting in the increased identification and, thus, decommissioning of non-profitable plants. However, nodal pricing is not commonly used in Europe and is not considered in new policies (Egerer et al., 2016). Nodal pricing faces some critiques. It would, for example, increase complexity in market clearing calculations and may make it easier to exercise market power because the market is smaller. Eicke and Schittekatte (2022) also mentions stakeholders who fear market liquidity reduction and the threat to market flexibility. They provide counter-arguments to all these issues while stressing that changing from a zonal to a nodal system would save operational costs. They warn that some of these worries also hold for a change to smaller bidding zones, while this option does not have all the advantages of a nodal system. The debate on switching to nodal pricing remains ongoing, but the EU has not taken any steps towards nodal pricing. Instead, they focus on splitting bidding zones into smaller zones.

Zonal pricing assumes that network capacity obstructions are most prevalent at zone borders. These obstructions can, however, also be present in the zones themselves. As trading within a zone is allowed while ignoring internal network constraints, intra-zonal flows are prioritized over inter-zonal flows. Internal congestion reduces the trading opportunities between zones, as network safety has to be maintained, and re-dispatching costs are to be minimized. This is why this internal congestion forms a problem for an efficient electricity system. As mentioned, congestion has intensified due to volatile power flows from renewable sources. It has also worsened due to the growing need for cross-border exchange (Plancke et al., 2016). The Netherlands is one of many EU member states that struggle with internal network congestion. It is a phenomenon that affects many countries. One other notable example in the EU is Germany. Germany has substantial renewable capacity in the north and a highly concentrated demand in the industrial south. As a result, power flows run from the north to the south, causing congestion. Congestion brings about re-dispatching costs for Germany and its neighboring countries.

The Agency for the Cooperation of Energy Regulators (ACER) has started an investigation of the current bidding zone configuration due to the increase of network congestion affecting numerous member states. The organization has ordered the Transmission System Operators (TSOs) of France, Germany, Italy, the Netherlands and Sweden to investigate new bidding zone configurations. (ACER, 2022). This project is called the Bidding Zone Review. For the Netherlands specifically, ACER has decided that the configuration of two new bidding zones should be investigated. On the instructions of ACER, Tennet, the TSO in the Netherlands, has started research into this alternative configuration (Tennet, 2023). The proposed reconfiguration would split the Netherlands into a north and a south zone. To explore these scenarios, Tennet and the TSOs of the other concerned countries will assess market efficiency and grid security. This research will result in a recommendation to perform or to hold off on the splits recommended by ACER. The recommendations of all involved TSOs will be discussed by their national governments. If needed, this is done with assistance from ACER. While writing this thesis, reports from the involved TSOs on the reconfiguration have yet to be published.

1.2. Knowledge gap

Numerous countries in the EU face increasing grid congestion. The split of electricity bidding zones is a possible long-term solution to tackle this issue. Splitting a large electricity bidding zone into smaller zones will improve the coherence between the market transactions and the physical grid (European Commission, 2024). Large bidding zones do not accurately represent the reality of the physical grid. After the split of a large zone, commercial exchanges will adapt to a new situation where certain exchanges will now have to go from zone to zone instead of inside one zone. Reconfigurating a zone will lead to a change in commercial exchanges based on what is economically efficient. This also means that network investments will be more efficient. Congestion will hence be lowered.

Next to internal congestion, the splits of large zones could also mitigate loop and transit flows in neighboring countries (Trepper et al., 2015). Loop and transit flows are unscheduled flows. They are flows that deviate from their commercial path. They create extra costs for the neighboring country through which they flow. Flows do not directly go on their intended path from the generator to the consumer. Electricity follows Kirchhoff's laws, going over all parallel paths in a network instead of via its commercial path (van den Bergh et al., 2015). This electricity behavior means there is a difference between commercial and physical flows. Loop and transit flows bring about extra system costs that could be minimized by transactions that match the grid infrastructure more closely. Due to the occurrence of loop and transit flows in the system, the total transmission capacity between zones cannot be offered to the market. According to Trepper et al. (2015), the split of the bidding zone of Germany could result in fewer loop and transit flows in its neighboring countries. The reduction of these unwanted flows will be the case because price signals will become more accurate and commercial exchange between the north and the south of Germany will be limited because of having this exchange more regulated. Transmission between the north and south of Germany is signaled as a significant contributor to neighboring countries' loop and transit flows. According to the European Commission (2024), re-dispatch in Germany could be reduced by 35-65% by splitting the German bidding zone into two zones. Another advantage they mention is leaving a large part of the market intact, which makes reforming procedures less complicated.

There are also some expected difficulties concerning the splitting of bidding zones. One issue mentioned by Bemš et al. (2016) is dealing with already signed long-term contracts. Trepper et al. (2015) also warn of political challenges. The splitting of the north and south of Germany will result in price differences in these two regions. As the north of Germany hosts a lot of wind generation, they will benefit from lower costs due to doing less export to the south. In turn, the consumers in the south could face higher prices. Electricity price differences in one country is a task that policymakers will need to deal with. Fraunholz et al. (2021) investigate the long-term effects on the efficiency of splitting the market of Germany. They conclude that the price difference between the north and south is expected to slowly decline between 2020 and 2035 due to grid expansion. However, it may again grow after 2035 due to the substantial expansion of renewable energy and no further grid expansion.

An interesting argument is made by Szabó (2017) and Janda et al. (2017), who show that the former German-Austrian bidding zone negatively impacted neighboring countries Poland and the Czech Republic due to dealing with the transmission that Germany cannot handle on its own. Szabó (2017) concludes that the zone causes a restriction on imports, which is prohibited according to EU rules. It is important to note that the EU has set the goal to make a minimum of 70% of the thermal limit of interconnections available for commercial trade (ACER, 2023). This goal will be mandatory starting in 2026 but has barely been reached. Another fascinating insight comes from EFET (2019), who show the negative impact of the splitting of the German-Austrian zone on the Austrian market liquidity and the costs of hedging positions. In their opinion, the decision-makers ignored these foreseen effects. The splitting of this zone also had some other effects, which Hurta et al. (2022) researched in their paper about the investment in energy storage systems. They conclude that the German market creates excellent opportunities for investment in this field, while Austria experienced worse investment opportunities after the split.

Ambrosius et al. (2020) explain that the uncertainty of this reconfiguration already targets market players. They found that risk is not distributed equally among market participants. "In general, generators with high investment costs carry the risk of investing not the right quantity and in the wrong locations, while generators with lower investment costs are not affected negatively by uncertainty."

(Ambrosius et al., 2020, p.14). This comment sheds light on the uncertainties that market participants are dealing with. National governments, TSOs, DSOs and energy companies will all be affected by this. Energy companies are responsible for supplying electricity to their customers. Continuing on this, energy companies that own power plants and sell electricity possibly have to adapt their decisions regarding investment strategies. The location of a new power plant or wind park will depend highly on the expected electricity price in the respective zone. Also, changes can be expected in the contracts with consumers.

Splitting the bidding zones can have a lot of advantages but also disadvantages. The pros and cons also depend on the stakeholder you are concerning. Eventually, national governments and the EU will decide on the potential splits. The expected consequences of the split in Germany have been discussed in many papers, and some have been explained in this literature research. However, a gap remains regarding the effects of a split in the Dutch bidding zone. ENTSOE (2018) has included LMP calculations to do their zone clustering (grouping nodes with a similar electricity price) and has done an elaborate stakeholder interview on The Bidding Zone Review. However, an in-depth analysis of the Netherlands is missing. A German split analysis will provide valuable insights into a Dutch split. However, it cannot be used to reflect precisely on changes in Dutch electricity prices or the relief in Dutch congestion costs. Furthermore, the research into the German bidding zone split does not mention any insights into the interaction of Germany and the Netherlands. This interaction may be vital to foresee the effect of both splits. Lastly, Germany's differences in geographical properties compared to the Netherlands, such as the locations of demand and generation, may have different effects on the respective splits. This also holds for the structure of the grid. Because of these differences, the specific effects of a split in the Netherlands must also be researched.

1.3. Research Questions

Because of the lack of studies on the Dutch bidding zone split, the impact of splitting the electricity bidding zone in the Netherlands is investigated in this master thesis. The impact is quantified by examining the possible change in cross-border exchanges and the effects on the day-ahead electricity prices. These potential changes will be analyzed, and the respective risks will be made explicit. The following research question is therefore posed:

MQ: How will splitting the electricity bidding zone in the Netherlands impact commercial cross-border exchanges and electricity prices in the Day-Ahead market in the Netherlands and its neighboring countries, and what risks does this split cause for energy companies?

The main research question is split up into four sub-questions. A literature review will be performed in the first part of the research to see what can be learned from past bidding zone splits. The case of the recent split of Germany-Luxembourg and Austria will be reviewed. Germany and Luxembourg were separated from Austria in 2018, making them two separate bidding zones. This first sub-question is posed to investigate the split:

SQ1: What were the effects of the split of the bidding zone of Germany-Luxembourg and Austria and how are they related to a split in the Netherlands?

The research method to explore this sub-question will be a literature review. Hart (1998), as cited in Randolph (2009), argues that a literature review plays a role in discovering essential variables relevant to the topic, establishing the context for a problem, and rationalizing the significance of a problem. In this case, the literature review can provide exciting insights into a similar split. Aspects such as electricity prices and changes in electricity flow effects on the neighboring countries can be reviewed. Results from this literature may provide a hypothesis for the split researched in this thesis. Next to this, it will provide context for the research.

Sub-question 2 will go into the fundamentals of modeling a bidding zone split. For this research, a fundamental model of the electricity market is needed. Much information is still being discovered as the split has yet to happen. Determining how to model this split using existing market data will be important. This sub-question is therefore stated as:

SQ2: How can existing market data be used to fundamentally model a split of bidding zones?

The answer to this question will serve as the basis of the modeling needed to answer the main research question. For this question, it is essential to know how the electricity flows will change after the split of the bidding zones. Data about the market right now is published by organizations such as ENTSOE and JAO. Load, generation, and information about flow-based market coupling, such as net positions, are available. Power production and consumer demand can be split according to the separation of the new zones. A big question remains regarding how the flow-based domains will change for these new zones. These flow-based domains are generally unknown, and TSOs keep a lot of information about flow-based domains secret. By performing the split, it will be impossible to know exactly what happens to these domains, as this is restricted to the TSOs.

Electricity prices are essential information for market players in the electricity market. If there is a split in the Netherlands, it will be interesting to know if there will be a difference in electricity prices between the newly formed zones and how significant this difference will be. This may affect policy decisions and market players' actions. Therefore, the following sub-question will be investigated:

SQ3: What happens to day-ahead electricity prices and cross-border exchanges after a split in the Netherlands in the newly formed Dutch zones and to the neighboring countries?

A model to answer this question is created based on the findings of sub-question 2. Spot prices for electricity can be based on marginal generation costs. Supply curves of power plants can be used to calculate the least cost dispatch. First, the situation 'as is' will be modeled by taking 2022 and modeling its electricity prices based on published load and generation data, together with the exact projection. These prices can then be compared to last year's actual prices to validate the model. Then, the model will be expanded to create the split, following the conclusions of sub-question 2. The same analysis can be done for inter-zonal electricity exchange. Finally, the second part of the main research question is investigated with this last sub-question:

SQ4: What risks exist for energy companies after the split and how can they be mitigated?

This sub-question will explore the risks that energy companies will face due to developments in electricity price differences or other effects identified in this research. Together, the research into these four sub-questions will answer the main research question.

1.4. Socio-technical aspects

This thesis aims to analyze the particular behavior of the electricity system, which can be classified as a complex socio-technical system. In a socio-technical system, the interaction between social and technical elements is recognized. In this section, it will be explained why the electricity system is a socio-technical system. Next to this, the fit of the topic into the Complex Systems Engineering and Management (CoSEM) master is explained.

According to de Vries et al. (2019), the electricity system can be described by three policy goals: Availability, affordability and acceptability. They are also called the 'triple A' goals. These three policy goals continuously balance and depend on social and technical elements. Scholten and Künneke (2016) describe the performance of these three goals as the interplay between techno-operational characteristics, energy market dynamics and institutional arrangements. They state that performance entails how institutions and technical alternatives influence the actors in this system and influence the commodity and monetary flows.

The technical side of the electricity system consists of the electricity grid. This encompasses power plants, transmission lines and substations. There are also power transformers, smart meters, voltage controllers, etc. The technical side also includes the electrical properties of transmission lines, the maintenance that has to be done on these lines as well as grid management. All these elements are important to consider when discussing the 'triple A' goals. When looking at the electricity system's institutional or social side, one can also name some properties. These are, for example, electricity market rules imposed by the EU or national authorities. Next to this, social elements such as environmental concerns, consumer demands, and different market players influence the electricity system. The two sides are intertwined and react to each other. These technical characteristics and institutional 'rules of the game' both constrain or influence the behavior of actors in the system (Scholten and Künneke, 2016).

The interaction between technical and institutional elements of system actors can be exemplified by the topic of this thesis research: a market bidding zone split. Following the societal pressure to pursue action on climate change, governments set certain sustainability goals. To reach these sustainability goals, governments will incentivize or support the expansion of renewable capacity. Furthermore, they can incentivize or demand further electrification of vehicles, industry, and heating. This will lead to certain actions by the involved parties. Energy companies may decide to invest in new wind parks and large factories may change their production processes. These changes will influence the technical side of the electricity system. The electricity system will endure increased pressure on the electricity grid. The increased pressure will have technical and financial implications, such as increased re-dispatching costs or the incentive to expand the grid. Again, this will influence the actors' decisions. In this case, policymakers will introduce a new intervention into the system: splitting a bidding zone. This split will then, in turn, impact social and technical elements. This example shows that these elements in the electricity system are highly interconnected and dependent on each other and should, therefore, be analyzed with a holistic approach.

The Complex Systems Engineering and Management master is concerned with the design and analysis of complex socio-technical systems. In the master's program, one is taught to design new interventions. This is done by analyzing the technical, institutional, and multi-actor processes aspects of a system. A holistic approach is needed to do an analysis that includes these factors. That is why this research will combine technical aspects, policy measures, and different stakeholders' interests. This is done by combining policy and technical aspects into modeling, with which quantitative research is conducted. This quantitative research is intertwined with qualitative research, which consists of a literature review as well as the application of quantitative research in a broader context. By taking this holistic approach, the complexity and interactions of the electricity system can be mapped and understood. In conclusion, the proposed research fits the CoSEM program well.

1.5. Research Structure

In this section, the research structure is clarified. Chapter 2 presents a literature review providing background information on market coupling and an analysis of a recent zone split. The background information on market coupling assists in understanding the modeling methodology used in the research. The background information consists of market coupling and the two methods presently used to calculate the inter-zonal market transmission capacity in the EU. Next, a study is conducted into the expectations and outcomes of the zone split between Germany and Austria. The result of this literature review will provide some interesting insights that can be used to analyze the split in the Netherlands. Next, Chapter 3 gives a detailed description of the modeling method, setup, and assumptions. In Chapter 4, the modeling results will be presented and discussed. In Chapter 5, the split is analyzed further with a discussion. Chapter 6 presents the conclusion, reflections and suggestions for future research.

2 Literature Review

In this chapter, a literature review is conducted to provide background information on market coupling and answer the first sub-question of the thesis. First, market coupling and cross-border transmission capacity calculation methods are explained. Additionally, insights about bidding zone sizes will be explained. This provides context to the research topic and the modeling methodology explained later. Secondly, the case of splitting the German-Austrian bidding zone is evaluated. This case is explained by clarifying the problems leading up to the split and the opposition from certain market players. Furthermore, the actual consequences of the split are investigated and compared to the expected outcomes. Lastly, the findings of this literature review are brought into the perspective of a possible split in the Netherlands.

2.1. Market coupling

The EU strives to have an integrated energy market and optimize energy allocation in its Member States (ACER, n.d.). An integrated energy market will increase competition and will be more robust and efficient. It will also improve overall social welfare (ENTSOE, 2021). These expected consequences make sense because the lowest-cost electricity can then be maximally shared with all market zones. To reach this large integrated market in the electricity field, EU countries exercise market coupling. Market coupling is the integration of electricity markets of different market zones. It integrates the purchase of cross-border capacity and electricity, which used to happen in two distinct steps. Market coupling uses a price coupling algorithm to calculate electricity prices and to allocate cross-border capacity (ENTSOE, n.d.-a). Market coupling makes the market more efficient and it causes an increase in price convergence between different zones (Epex Spot, n.d.). The coupling ensures a better reflection of the electricity system, as the grids of neighboring zones are physically interconnected and the electricity flows go across market boundaries (Next Kraftwerke, n.d.). Market coupling is used in the day-ahead market as well as in the intra-day market.

The first market coupling in the EU was executed in 2006, when the Netherlands, France and Belgium coupled their day-ahead markets. In 2010, Luxemburg and Germany were also connected, which completed the market coupling of the Central West European (CWE) region. At the same time, the Price Coupling of Regions (PCR) system was introduced. In the following years, more countries were added to this collaboration, and it now consists of 19 countries (Next Kraftwerke, n.d.). The coupled countries are displayed in Figure 2.1.

Two essential parties are involved in the PCR: The TSOs and the Nominated Electricity Market Operators (NEMOs). NEMOs are the responsible parties for the day-ahead and intraday markets. EPEX SPOT and NordPool EMCO operate as NEMOs in the Netherlands, among other countries. The TSOs send in all their network capacities and constraints and the NEMOs of all coupled zones send in the market orders, which they have collected from market participants. The PCR algorithm matches demand bids and supply offers, which maximizes overall social welfare. The clearing prices, scheduled exchanges, and net positions are then reported to all parties (ENTSOE, n.d.-a).

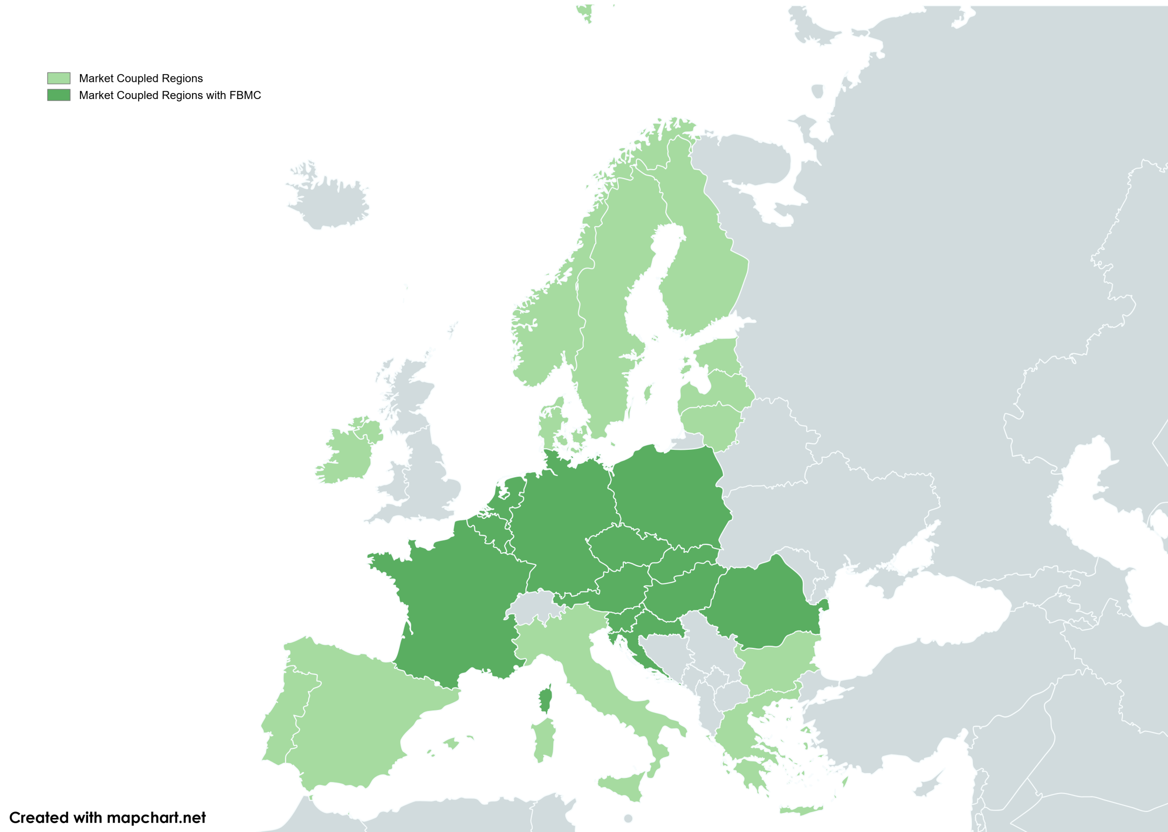


Figure 2.1: Overview of coupled regions in Europe

2.1.1. Cross-border capacity calculation

Electricity flows through interconnectors that connect the electricity grids of the coupled zones or countries. These interconnectors are electricity lines going from one zone to another, thus connecting the different grids. A specific cross-border transmission capacity is made available to the market to facilitate transactions from zone to zone. This transmission capacity between different zones must be calculated to offer it to market participants. Transmission lines have physical limits that are constrained by specific electrical properties. Additionally, they can be limited by already planned flows. The internal constraints of a zone can also limit commercial transmission capacity. Thus, a difference exists between the actual physical transmission capacity of a cross-border line and the commercial transmission capacity offered to the market. The commercial transmission capacity between zones can be calculated in different ways. In a large part of the EU, Flow-Based Market Coupling (FBMC) is currently employed for capacity calculation in the CORE region. This was previously done with Net Transfer Capacities (NTC). The new FBMC method has been used since the 20th of May 2015 (Tennet, 2015). FBMC was first used in Central Western Europe (CWE). The CWE includes Belgium, France, the Netherlands and Germany-Austria-Luxembourg. Since 2022, FBMC has been expanded to the entire CORE region, which covers 13 member states (ENTSOE, n.d.-a). The overview of all coupled zones in Europe, with and without FBMC are displayed in Figure 2.1. The Nordics are expected to join FBMC as well from October 2024 but have experienced some delay. Unlike NTC, FBMC captures physical flows in parallel network elements (Riskutia, 2023). The new method represents the physical electricity flows better and makes the available trading domain bigger, but the modeling process becomes more complex. The two different capacity calculation methods, NTC and FBMC, will now be explained and compared as they are used in the modeling process of this thesis.

2.1.2. Net Transfer Capacity

In the NTC method, one value for commercial transmission capacity on every bidding zone border is calculated in both directions. There will be a value on every border for import and export. This calculation is done by every TSO individually and then harmonized with their neighbors (ENTSOE, 2021). All countries do this with their individual available data and assumptions. As a result, the calculation for one cross-border might differ for the two countries. If they differ, the lowest value is taken (ENTSOE, 2021). This harmonization of individual calculations can make the estimation too conservative.

Physical transmission constraints and specific safety standards limit the commercial transmission capacity. Furthermore, a prediction of parallel flows coming from other zones is brought into the calculations (van den Bergh et al., 2015). The Total Transfer Capacity (TTC) is thus set by the thermal limit of the transmission line and its electrical properties. This TTC also considers the possibility of line outages and loop and border flows coming from other countries. Furthermore, there is a certain Transmission Reliability Margin (TRM), which captures system uncertainties (ENTSOE, 2021). Their relationship is shown in this equation:

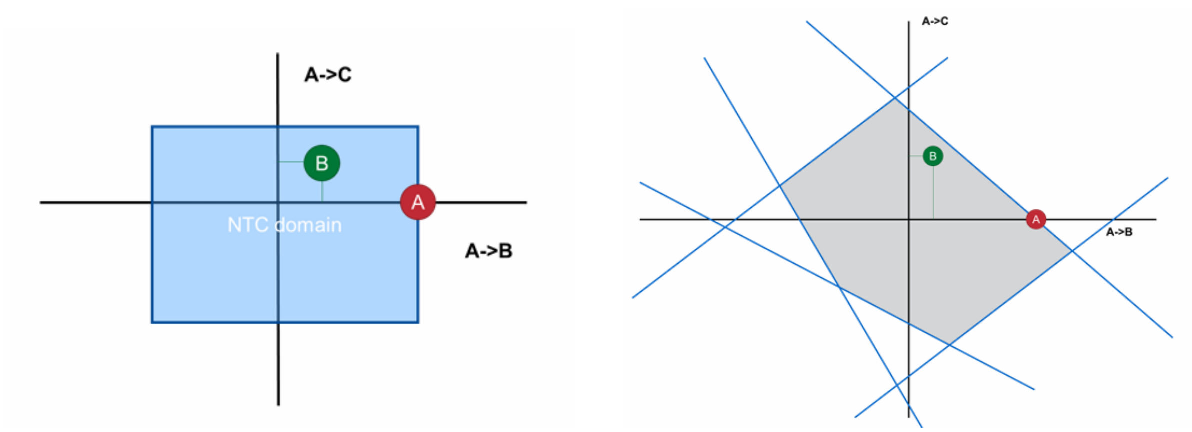
$$TTF - TRM = NTC \tag{2.1}$$

The Net Transfer Capacity (NTC) is then the capacity that remains for the market. So, a line is constrained in both positive and negative directions. This is expressed based on van den Bergh et al. (2015) in the following way:

$$\mathrm{NTC}_l^{min} \leq F_l \leq \mathrm{NTC}_l^{max} \qquad \forall l \tag{2.2}$$

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

Where F_l is the flow through a transmission line and $(NEX)_z$ are the Net Exchange Positions of the zones. $A_{t,z}$ is an incidence matrix that represents the relationship between the market zones and the cross-border links. There are some downsides to the NTC method. As mentioned before, it is a conservative calculation that underestimates the commercial transmission capacity. With NTC, the commercial transmission capacity of a cross-border line is calculated independently of other cross-border transmission lines. This makes the available capacity a conservative calculation because the TSOs do not want to override security constraints. Figure 2.2a presents the NTC domain. The import and export limits for the borders of zone A to zone B and zone A to zone C are visualized. In market result A, the capacity of A to B is fully used, and there is no exchange in the direction of A to C. It is also important to highlight that no more exchange is possible from A to B regardless of a change in the exchange between zone A and zone C. Market result B shows a transaction in the direction of A to B as well as A to C (ENTSOE, 2021).



(a) NTC domain **(b)** FBMC domain

Figure 2.2: Graphical presentation of the NTC domain and FBMC domain (Sourced from webinar slides of ENTSOE (2021))

2.1.3. Flow Based Market Coupling

The second method used to calculate the cross-border capacity is called Flow-Based Market Coupling (FBMC). This method better represents the system's physical transmission constraints. The internal transmission constraints in a zone can limit the inter-zonal commercial transmission capacity. The TSOs identify all critical lines in the zones that constrain this capacity. These lines are called Critical Network Elements (CNEs). The other lines are thus irrelevant to this problem and not considered. For every CNE, a Remaining Available Margin (RAM) and a Power Transfer Distribution Factor (PTDF) are calculated (ENTSOE, 2021). The RAM remains after subtracting a safety margin and all internal flows, loop flows, and forecasted flows from non-CORE exchanges. The PTDF describes the sensitivity of flows on a transmission line to a power injection in a particular zone (Riskutia, 2023). This is a weighting factor between 0 and 1. The RAM and PTDF are calculated based on a common grid model and with a list of CNEs from the TSOs (ENTSOE, 2021). This is an advantage compared to the calculation in the NTC approach. In the NTC approach, assumptions made in the capacity calculation are not shared, and the calculation is not coordinated. The FBMC method is more transparent, as the calculation is based on the CNEs. The grid model must, however, still be matched between TSOs. The transmission constraints for FBMC are described by van den Bergh et al. (2015) like this:

$$-RAM_l \leq F_l \leq RAM_l \qquad \forall l \tag{2.4}$$

$$F_l = \sum_z \mathrm{PTDF}_{l,z}^{zon} \cdot NEX_z \qquad \forall l \tag{2.5}$$

In Equation (2.4), the flow through the transmission line F_l is constrained by RAM_l, which is the Remaining Available Margin of the critical line l. In Equation (2.5), the net position NEX_z is constrained with the zonal PTDFs. So, the net position of a zone is constrained by the RAM and the PTDFs of the specific critical lines. These critical lines are the critical network elements. By applying the FBMC method, the cross-border commercial transmission capacity is not calculated independently from other lines but based on the whole system. Figure 2.2b displays the new commercial transmission capacity with FBMC. The physical properties of the grid are now better represented, which will make the FBMC flow domain bigger than the NTC one (van den Bergh et al., 2015). The blue lines in Figure 2.2b constrain the import and export limits. These blue lines represent the CNEs, which are limited by the RAM and the PTDF. The RAM is represented by the distance from the origin, and the PTDF is represented by the incline of the blue line (ENTSOE, 2021). Again, in market result A, the transmission capacity of A to B is fully used, and there is no exchange in the direction of A to C. The two are compared in Figure 2.3. The difference in the transmission domain can now clearly be compared. In the FBMC case, depending on the exchange between A and C, the exchange between A and B can be higher. This is illustrated in the figure by moving point A down to the right.

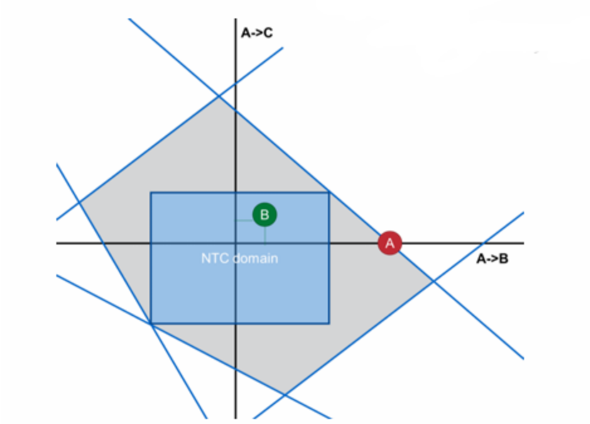


Figure 2.3: Comparison of the NTC and FBMC domain (Sourced from webinar slides of ENTSOE (2021))

2.1.4. Bidding zone size

The market coupling of multiple bidding zones and the different capacity calculation methods have now been explained. Let us now focus on the bidding zones themselves. Most bidding zones are defined with their national borders. In Figure 2.4, Europe's current bidding zone configuration is displayed. It can be observed that Norway, Sweden, Denmark and Italy have multiple bidding zones. It can also be observed that Germany and Luxembourg form one bidding zone. If there is unlimited cross-border commercial transmission capacity available between different zones, prices will converge. However, the prices will differ if the transmission lines are congested (de Vries et al., 2019). In zonal pricing, it is assumed that network capacity obstructions are most prevalent at zone borders. This is, however, not necessarily the case. Bidding zones are based on national borders for historical and practical reasons. They are not necessarily based on their grid layout or congestion patterns. It has been suggested to research alternative bidding zones that do not prioritize national borders, but this research has been discarded for practical reasons (ACER, 2024).

Bidding zone sizes mainly vary by the size of their countries. This results in large bidding zones for large countries and small bidding zones for small countries. Large bidding zones have some disadvantages. It is assumed that electricity can be traded freely within one bidding zone as if there are no transmission capacity restrictions (Synertics, 2023). A large zone with unlimited internal transmission capacity is also called a copper plate, as copper is a good thermal conductor. No price differences within a zone exist, but they are all assumed to be similar. In reality, these constraints do exist, and there are regional price differences. Having a large zone means there is bad price signaling. This could lead to congestion and re-dispatch. Congestion in these large zones, in specific critical network elements, may restrict cross-zonal exchanges. Therefore, it may be better to split large zones in some cases.

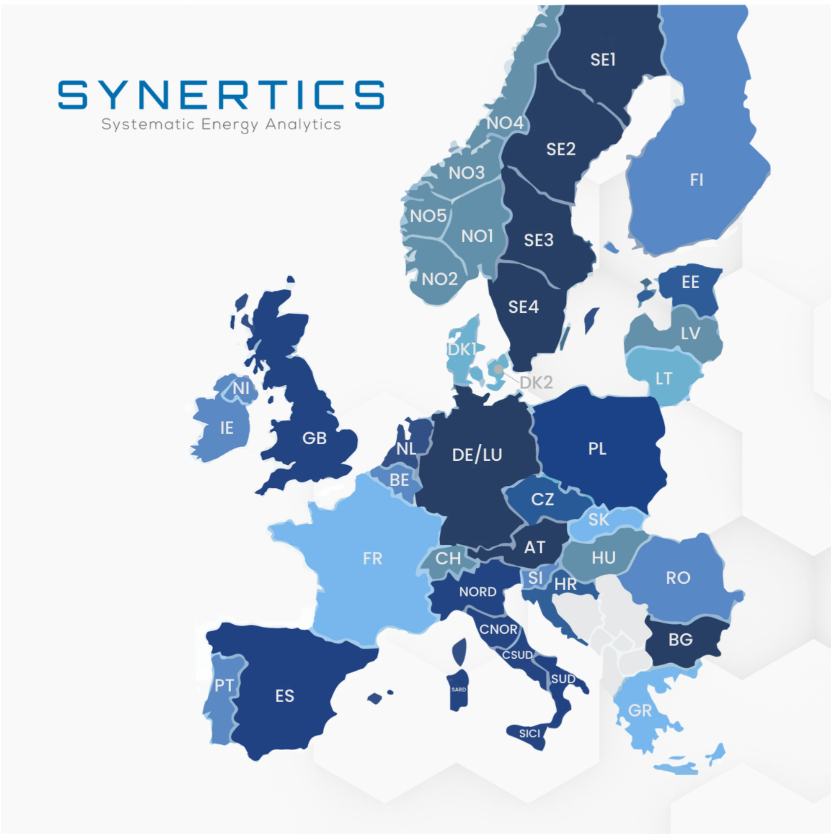


Figure 2.4: Bidding zone configuration in Europe (Sourced from Synertics (2023))

2.2. The split of the German-Austrian bidding zone

The splitting of electricity bidding zones is not a new concept. It has happened continuously over the past few decades. The most recent split in the area of interest, the CORE region, is the split of Germany-Austria-Luxembourg (DE-AT-LU). This split will be analyzed in this section.

2.2.1. Current bidding zone problems in the Netherlands and other EU countries

The insights into the split between Germany and Austria can provide insights into a split in the Netherlands. Let us first examine why there will be a possible split in the Netherlands and some other EU countries. The EU has a vision and specific goals for an integrated European energy system. This energy system is called the European electricity target model. In this target model, bidding zones should be based on network congestion, not necessarily on national borders (ACER, 2022). Because congestion exists beyond bidding zone borders, research is being done into new bidding zone configurations. ACER (2022) names three main benefits of bidding zone reconfiguration. These are increased availability for cross-zonal trade, more efficient network investments and cost-efficient integration of new technologies. The EU has set the goal to have 70% of the total transmission capacity available for commercial exchanges, respecting operational security limits after deductions of contingencies of inter-zonal transmission capacity starting from 2026, but preferably earlier. In Decision No 11/2022, ACER decided on the bidding zone configurations that need to be researched by TSOs in Germany, France, Italy, the Netherlands and Sweden. In this decision, discussions between TSOs and other stakeholders are included. Some TSOs have suggested not simply investigating bidding zone reconfigurations for member states separately but rather by doing a combined study. This would better represent the benefits of splitting bidding zones, as member states are interconnected. ACER strives to keep the research manageable but has decided to include these combinations in its decision. TSOs had expressed interest in researching a combination of France, Germany and the Netherlands. Finally, it was decided that based on the individual configurations, two combinations of two member states will be proposed for investigation in the next steps. These combinations are interesting to investigate because it may not be beneficial to split one bidding zone while not splitting the bidding zone of the neighboring country. A split in Germany and France will also affect the Netherlands as this area is interconnected. However, in the first step, TSOs will only research the individual member states' bidding zone splits.

In a recent report, ACER (2024) released numbers about the current state of transmission capacities for cross-zonal trade. In this report, they published numbers concerning grid congestion costs and renewables that have been curtailed. Congestion costs for 2023 in the EU exceeded 4 billion euros. The German electricity system incurred 60% of these costs. Also, in 2023, 10 TWh of renewable energy in Germany had to be curtailed due to congestion. This was about 4% of their total renewable generation that year. Furthermore, only two member states have reached the goal of 70% available transmission capacity for commercial exchanges of the physical capacity of the critical network elements. These two member states are the Czech Republic and Slovenia. Germany and Austria score badly on these stats. Measured from June to December in 2022 and 2023, Germany had an average hourly margin of 33% and 41%, respectively. Austria scored with 35% and 33%. Both are way lower than the goal of 70%. Germany is known for having difficulties concerning congestion because of a mismatch in high renewable generation in the north and a high demand in the industrial south. This causes them to curtail renewables and, among other reasons, to have congested critical network elements, which influence the cross-zonal trade. The Netherlands is also an underachiever, based on their average minimum hourly margin available for cross-zonal trade. They score 36% in 2022 and 39% in 2023. The Netherlands, too, faces problems with congestion. In 2022, Algemene Rekenkamer (2022) concluded that the congestion problems are leading to a delay in renewable energy growth. It is clear that the Netherlands and Germany, among other member states, have severe congestion, leading to restrictions on cross-border trade and the further development of renewables.

2.2.2. Issues regarding the former DE-AT bidding zone

In the first bidding zone review performed in the EU, ENTSOE (2018) investigated numerous reconfiguration scenarios in the CORE region. This bidding zone review also included a new configuration where Germany and Austria were separate zones. Germany and Austria joined by Luxembourg, have formed a common bidding zone since 2005 (Szabó, 2017). After running into problems with the operation of this bidding zone and a lot of arguments for and against the split, it was decided by the German regulator, assisted by ACER, to split Austria and Germany-Luxembourg (DE-LU) from the 1st of October in 2018 on (EFET, 2019). A literature review will be conducted to uncover the motivations behind the split and to map the corresponding consequences. This literature review supports the main research by highlighting the relevance of research in this field and drawing important lessons learned from the past that may apply to the current research case.

To understand the issues in the DE-AT area, one has to understand the concept of unplanned power flows. An unplanned power flow can be defined as the discrepancy between a commercial and a physical flow (ČEPS et al., 2013). A commercial flow is the electricity that was agreed to be exchanged between zone A and adjacent zone B. However, electricity does not necessarily follow exactly as scheduled. According to the Kirchhoff laws, electricity flows through all parallel paths in the network (van den Bergh et al., 2015). This means that a commercially scheduled flow going from zone A to zone B, may not travel between these zones directly. Electricity can travel from zone A through neighboring zones before arriving in zone B. The flow that deviates from its path is called the unplanned flow. Unplanned flows can be classified as loop flows or transit flows. A loop flow describes the detour of the flow through a neighboring country when planning to flow internally, thus from one location in zone A to another in zone A. A transit flow describes a flow scheduled between zones A and B, which flows via another or multiple other zones instead of going directly between them. Szabó (2017) describes two problems that these unplanned flows cause. One problem is the cost of additional re-dispatch to keep the transmission between safety limits. The other problem is that they cannot be controlled by the market. They take away cross-border commercial capacity. TSOs must account for these unscheduled flows to keep all flows between safety limits. Accounting for these unscheduled flows means lowering the transmission capacity that is offered to the market.

In a joint study by the TSOs of the Czech Republic, Hungary, Poland and the Slovak Republic, the issues of these unplanned power flows were researched, explicitly focusing on effects in the Central East European (CEE) region due to transactions in the German-Austrian market. Germany and Austria originally formed one common bidding zone (together with Luxembourg), where electricity could be freely allocated. Having a common bidding zone means that flows between Germany and Austria are considered internal transactions. The hypothesis that transactions between Germany and Austria lead to unplanned flows in neighboring countries was confirmed in this research. A significant difference was found between commercial and physical flows between Germany and Austria. Additionally, a correlation was found between the DE-AT exchanges and unplanned flows between Germany and Poland (ČEPS et al., 2013). It was concluded that scheduled DE-AT flows, for a significant part, travel through neighboring countries instead of passing directly through the DE-AT border. These unscheduled flows mostly went through Poland. The sentiment was that market participants traded on the geographical border DE-AT freely. At the same time, surrounding TSOs were stuck with the burden of associated grid congestion costs because of housing these flows. The burden of these congestion costs from Austrian and German transactions led to dissatisfaction among the neighboring countries that executed this study. In this study, the four TSOs underline their wish for a split to improve the market design. The TSOs also argue that the effects of the Flow-Based Market Coupling approach – a way of optimizing cross-border allocation – would fall short without implementing the split.

Singh et al. (2016) conclude that there are two main reasons for the unscheduled flows in the CEE region. The first is the increasing presence of renewable energy in North Germany, while transmission infrastructure to the south is lacking. The second is that large ‘transactions’ are being done between Germany and Austria that cannot directly be captured in the commercial transmission capacity between the two. The transactions are not inter-zonal, as power can be allocated freely in their common bidding zone. One could argue that these ‘transactions’ are thus only artificially made feasible by keeping the zones of these countries together. Both of these problems are a result of insufficient transmission capacity. In other words, on a windy day, Austria will profit from cheap electricity prices coming from German wind turbines while the surrounding countries deal with the burdens coming from it. While steps are being taken to expand the grid in Germany, this expansion will take a lot of time and is difficult to realize. The slow grid expansion will not solve the problems of unplanned flows quickly.

Szabó (2017) holds Germany accountable for the problems arising from the increasing renewables in the north. According to this author, Germany has not taken any steps to mitigate the congestion issues. Assessing the unscheduled flows in the AT-DE zone has shown an excessive amount of unscheduled flows, even when considering expected loop and transit flows that arise due to the nature of physics. Szabó (2017) even accuses Germany of breaking EU rules by preventing the free movement and trade of goods. This is the motivation behind the 70% available transmission capacity rule that the EU already has in place and will make mandatory in 2026. In summary, there are a lot of objections to this member state's shared bidding zone.

2.2.3. Opposing views

While most countries in the CEE region strongly encouraged a split between Germany and Austria, there were also dissenting voices. One argument against market splitting is the decline of market liquidity. ENTSOE (2018) describes market power as the degree to which a market participant can sell capacity without significantly impacting the electricity price. In a market with high market liquidity, there are a lot of buyers and sellers. This liquidity helps to clear the market more efficiently. In a market with high market liquidity, there are fewer risks involved for market participants, as energy is traded more quickly. High market liquidity reduces market power, which is the power that a certain market participant has to influence the electricity price. If a certain market player has a significant share of the available assets in a certain zone, it can strategically influence the market. This is not desirable, as it would decrease overall social welfare. For instance, parties with high market power could withhold capacity to increase the clearing price. A larger market zone will naturally have more market liquidity than a smaller zone. Therefore, the fear of reducing market liquidity and thus increasing risks for market participants was an argument against the DE-AT split. The European Energy Exchange (EEX), agreed with this statement, arguing that they have a long-term objective of having larger bidding zones as they create liquid power markets (Kristoferitsch and Stangl, 2017).

Another objecting party was Austria itself. Unsurprisingly, Austria was unhappy about the prospective split as well. After the report was released from the CEE TSOs, discussions with ACER were held which led to the decision to do a split. Following this split, Austrian market players feared that market liquidity would decrease. They also expected a rise in the costs for trading and purchasing electricity following the split (Kristoferitsch and Stangl, 2017). Additionally, they argued that the long-term contracts that they made with suppliers in Germany were based on a common bidding zone. These contracts would then face uncertainties and would need to be renegotiated. Furthermore, it was questioned if the problem was the lack of transmission capacity between Germany and Austria and not the internal congestion of Germany itself. Rajal (2017) explains that the National Regulatory Authority (NRA) of Austria and the Austrian TSO have provided evidence of the absence of physical congestion between the two countries. According to ACER, the congestion of the specific interconnector is not the only issue they are held accountable for, but also the congestion caused in another location through the actions of the cross-border trade. The Austrian NRA and TSO tried appealing ACER's decision, considering this congestion argument but also arguing that ACER should not be the one to have made this decision. These appeals did not pass, and Austria finally made some agreements with Germany to minimize the impact on their transmission network.

2.2.4. Consequences of the split

The goal of the DE-AT split was to reduce loop and transit flows and thus reduce the pressure on the grid of the neighboring countries. The biggest objections against the split were the loss of market liquidity, price differences in Austria and the expectation that this split was not the leading cause for congestion issues in CEE, but that these issues lie in the internal network of Germany. As the split happened in 2018, the impact of the split can be evaluated. This is done for the impact on electricity prices, unscheduled flows and market liquidity. The split took place on the 1st of October. The two zones immediately showed some price differences, which are displayed in Figure 2.5. This data is taken from ENTSOE (n.d.-b).

As predicted, the day-ahead prices of Germany and Austria slightly diverge from each other. Austria shows structurally higher prices. This may be explained by the limitations of trade going from Germany to Austria. In Figure 2.6, the distribution of the new prices can be seen with boxplots. This figure shows the day-ahead prices for the whole of 2018. Therefore, the prices after the split are slightly higher as they cover the winter months. It can be seen in this figure that Austria experiences higher prices than Germany.

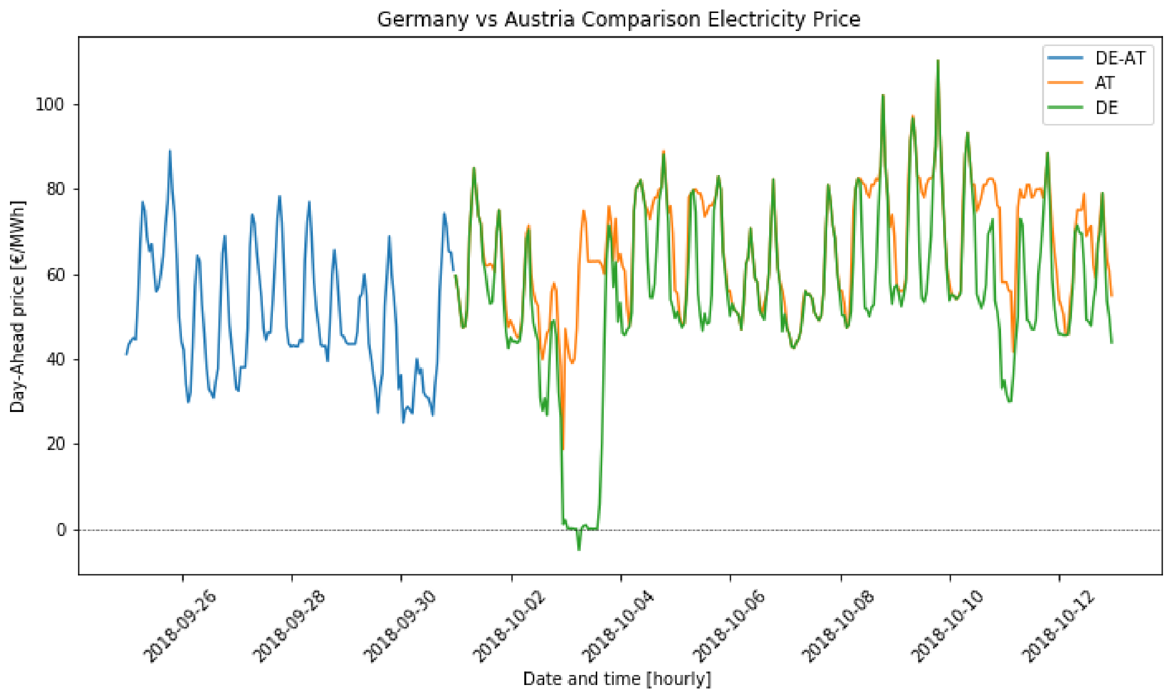


Figure 2.5: Moment of split

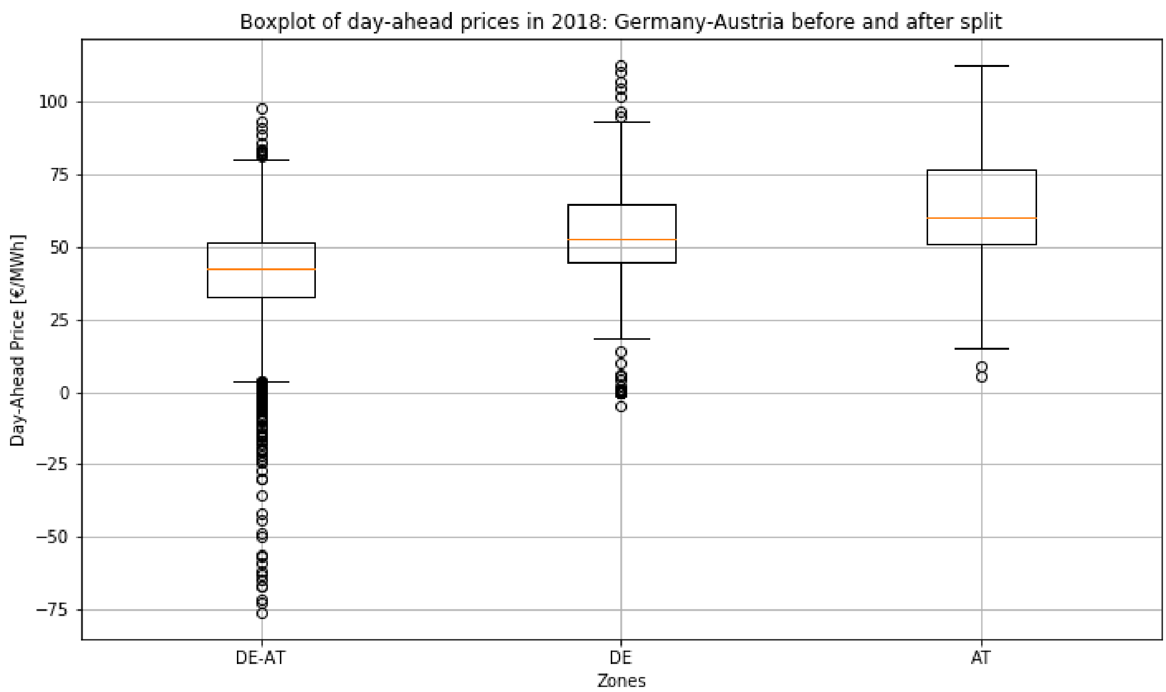


Figure 2.6: Comparison of day-ahead prices before and after split

To provide a more recent view of the situation, the day ahead electricity prices of 2022 are also compared. In Figure 2.7, the prices of Germany and Austria are again compared. The price difference is plotted to provide a clear view of the whole year. The price of Austria minus the price of Germany is shown. This figure shows that Austria still experiences higher prices for a large part of the year. The hours in which prices of these two zones converge are limited, implying insufficient available transmission capacity between the two zones.

Furthermore, it is relevant to examine the discrepancy between the scheduled commercial flows and the physical cross-border flows before and after the split. In Figure 2.8, commercial and physical flows are compared before and after the split. The data used for this is the entire year of 2018. The number of unscheduled flows was expected to decrease when a split was made. In this figure, it can be seen that there is a decrease in the difference between commercial and physical flows after performing the split in both directions. This indicates that the expectation has proved to be true.

The effect on the cross-border flows after the split has also been analyzed by Graefe (2023). This author analyzed the effects of the DE-AT split on the cross-border flows in Germany, Austria, Poland, the Czech Republic, Slovakia and Hungary. The main goal of doing this split was mitigating the unscheduled flows in the neighboring countries of Germany. Graefe (2023) found a reduction of nearly 3 GWh/h in commercial planned flows between Austria and Germany. For the other countries, the planned flows increased, especially in Poland. As for the unplanned flows, there was a decline between Germany and Austria of 2.7 GWh/h. Furthermore, the Czech Republic and Slovakia also experienced less unplanned flows with 40% and 45% compared to before the split. In Hungary, there were no significant effects. The analysis for Poland remains unclear.

Next, the worries regarding market liquidity are addressed. Market liquidity is difficult to measure, but it plays an important role in the electricity market. Pototschnig (2020) and Compass Lexecon (2024) name a few indicators for market liquidity. These are traded volumes, bid-ask spreads and churn rates. Traded volumes are the total electricity volumes traded over a certain period of time. A bid-ask spread is the difference between the highest bid price and the lowest ask price. In a liquid market, this bid-ask spread is low, as sufficient parties are willing to trade. Lastly, churn rates are defined as the total traded volume divided by its targeted physical demand (Compass Lexecon, 2024). A high churn rate indicates a competitive and liquid market as more transactions are done.

These three factors are evaluated for the case of Germany and Austria. Pototschnig (2020) finds that traded volumes for Germany and Austria increased by 13% comparing 12 months before the split to 12 months after the split on the EPEX Spot market and by 30% on the EXAA market. EPEX deals with trades through multiple European countries, while EXAA deals with trades in Austria and Germany. Furthermore, the churn rate in Germany has not changed significantly after the split of the DE-AT bidding zone. The author points out that these two phenomena cannot be proven to be directly linked to the market zone splitting. However, he argues that there are no indicators of a reduction in market liquidity after the split. Compass Lexecon (2024) also states a traded volume increase after the split, attributing it to the reconfiguration. They explain that market players now have to close positions in both market zones instead of netting their positions. This could explain the increasing trade volumes.

The increase in traded volume explained in the previous section considers short-term trade only. Long-term markets have different dynamics. One of the arguments made by opposing parties was the difficulty of managing long-term contracts in the event of a split. Directly after the split, DE-AT-LU futures were adapted to DE-LU and AT futures by settling them on a price with a weighted average of 9:1 (DE:AT). Austrian prices were now only a small influence (Compass Lexecon, 2024). It was also found that the number of forward contracts initially dropped in both countries. In Germany, there was a recovery, but Austria lagged. Financial transmission rights were introduced to mitigate this (Compass Lexecon, 2024). Compass Lexecon (2024) describes some positive recovering effects on the churn rate and bid-ask spreads in Austria after the first downgrade of the split. However, these market liquidity metrics were never restored to their pre-split levels.

From this literature review of the split of the DE-AT bidding zone, a few things can be concluded:
1. The unscheduled flows, which were the main reason for the split, have declined in numerous countries surrounding Germany and Austria, including Germany and Austria themselves. What stands out in this literature review is that the unplanned flows in Poland, which was identified as the country that suffered the most from transactions between Austria and Germany, have not reduced.
2. There has been a decrease in planned flows between Austria and Germany, but an increase in the planned flows in the neighboring countries, especially in Poland.
3. The worries of Austrian market players concerning the rise of electricity prices can be confirmed. As expected, the Austrian prices have deviated from the German prices and have risen higher. This is probably due to the now limited trade between Austria and Germany.
4. There are some indicators that Austria did not recover in market liquidity after the split. In Germany, this doesn't seem to be a problem. These liquidity problems happened in the long-term markets. Short-term markets were not affected.

2.2.5. Perspective on a split in the Netherlands

The issues concerning Austria, Germany and the Netherlands have been addressed. The split of DE-AT is now compared to the situation in the Netherlands. The main reasons for splitting the DE-AT zone were the unscheduled flows and congestion in neighboring countries. Similarly, the main reason for the proposed bidding zone configuration is congestion. In the DE-AT zone split, neighboring countries suffered from unscheduled flows caused by transactions between Germany and Austria. Research into this by Austrian market players also found that this was primarily caused by congestion in Germany. The Netherlands also suffers from loop flows coming from Germany. However, loop flows from the Netherlands affect Belgium and Germany as well (ACER, 2024). Internal congestion causes these loop flows. The mismatch of abundant renewable energy generation in northern Germany and higher demand in the south, combined with demand in Austria, created bottlenecks in the grid. This may also be the case in the Netherlands, which has a high concentration of offshore wind farms just off the shore near the country's north. Furthermore, the largest part of the consumption is located in the south of the Netherlands. This may lead to friction and should be investigated. To illustrate the similarities and differences, Figure 2.9 roughly shows the population density and the wind capacity in the Netherlands, Germany and Austria (based on Open infrastructure Map (n.d.)). The Figure shows that the population of Germany is very high compared to the population of Austria. The same holds for the population in the south of the Netherlands compared to the north of the Netherlands. Furthermore, the figure shows a rough distribution of wind capacity. Germany has a lot of wind energy compared to Austria. In the Netherlands, the wind capacity in the north is very large compared to the small population. However, the expansion of wind projects near the west and south coast of the Netherlands is developing. Next to households, the demand for electricity also comes from industry. Germany is known for having a lot of industry in the country's south.

A mismatch in demand and generation can cause congestion. However, congestion between the north and the south of the Netherlands could also result from large loop flows induced by Germany, not necessarily by internal problems in the Netherlands. In the case of the DE-AT split, Austria experienced higher prices after the split. A similar effect may be expected in the Netherlands due to the amount of renewables in the north compared to the low population. Next, the DE-AT split has led to a decline in trade between Germany and Austria, as the cross-border flows now require implicit allocation. When performing a split in the Netherlands, inter-zonal transmission capacity from the Netherlands to neighboring zones will change, as internal network constraints will be more present in the market clearing.

Market liquidity was also negatively affected in Austria after the DE-AT split. Germany did not suffer from the split in the same way. This may be explained because the market in Germany is nine times bigger than Austria's market (ENTSOE, n.d.-b). In the Netherlands, this could also be a consequence, with a smaller northern market compared to a bigger southern market. The reduction in liquidity could cause problems for market players. Another effect of the DE-AT split was the change of long-term contracts. These contracts need to be changed or renegotiated to match the new bidding zones. In the Netherlands, this could be solved with instruments similar to those used in the DE-AT split. Setting a price based on market size and using FTR. Finally, a big difference between the split of Germany and Austria and that of the bidding zone of the Netherlands is that the latter does not concern two separate countries. The policy needed for the changes to be made in the new bidding zones in the Netherlands would be an internal matter. This simplifies the process. Furthermore, the Dutch government mostly has its own interests at heart.

The two splits share some similarities but also many differences. The past has taught us that a bidding zone split can change the market dynamics of the zone and its neighboring countries. What will happen to trade in a new Dutch bidding zone remains unclear. The split of the Dutch bidding zone could lead to a price difference, such as with DE-AT, but the market zone is small compared to the German zone. It may not have as big of an impact as it did for Germany and Austria. More research is needed into the Dutch bidding zone split, specifically on the new commercial transmission capacity (in)between the Dutch zones and their neighboring countries. The next chapter develops a modeling strategy to investigate this further.

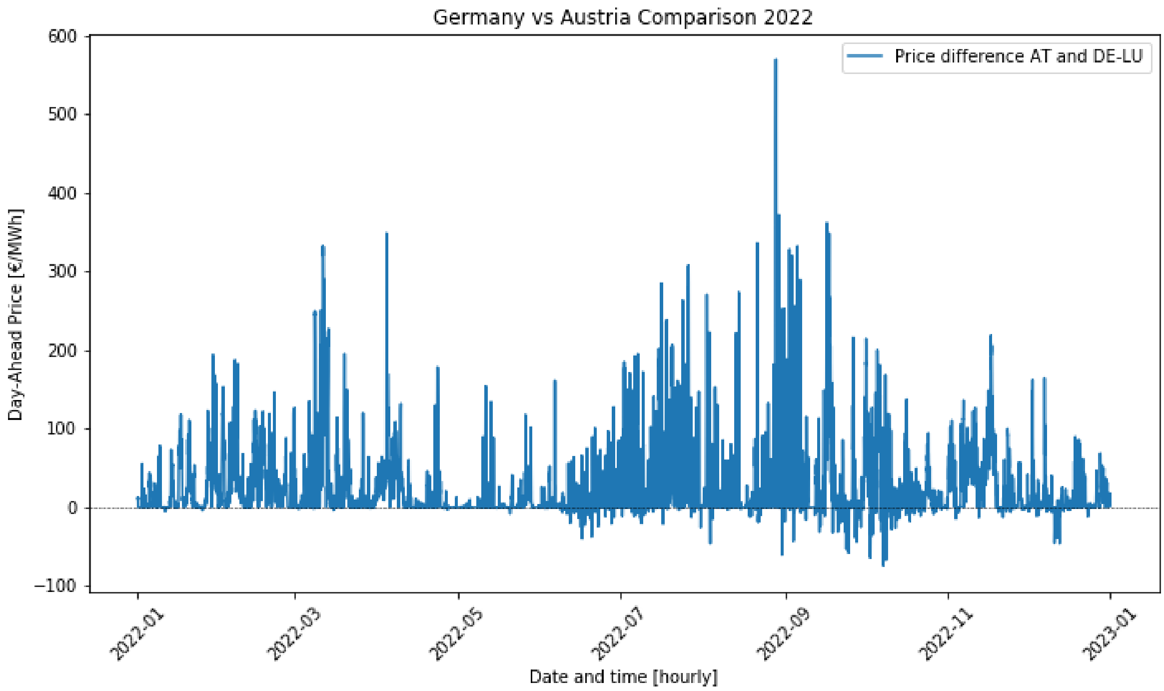


Figure 2.7: Comparison of day-ahead prices in 2022 - Austrian price minus German price for every hourly timestep

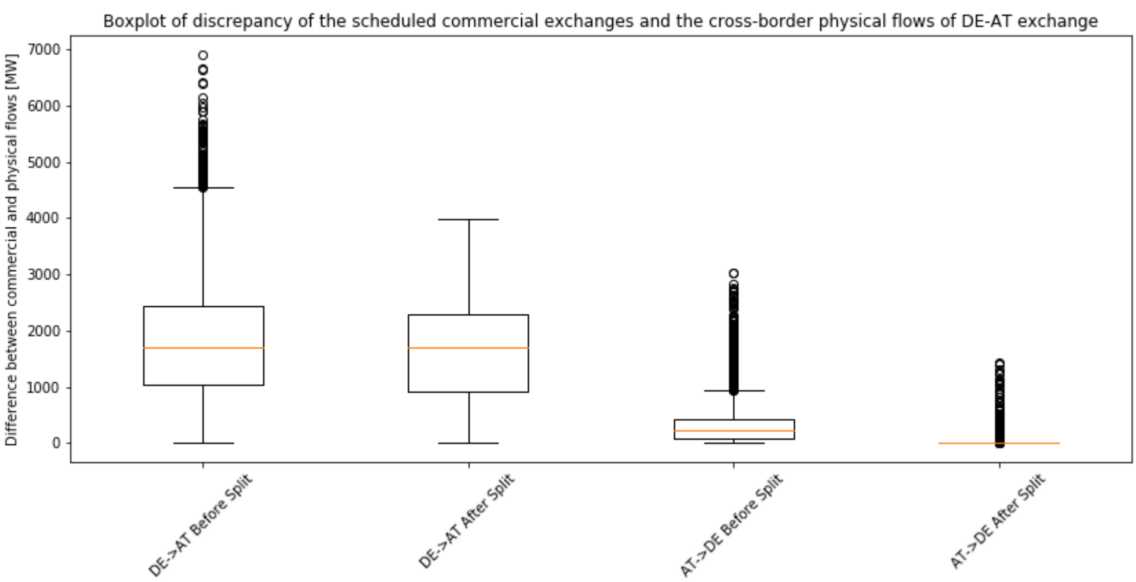


Figure 2.8: Difference between commercial scheduled flows and physical cross-border flows

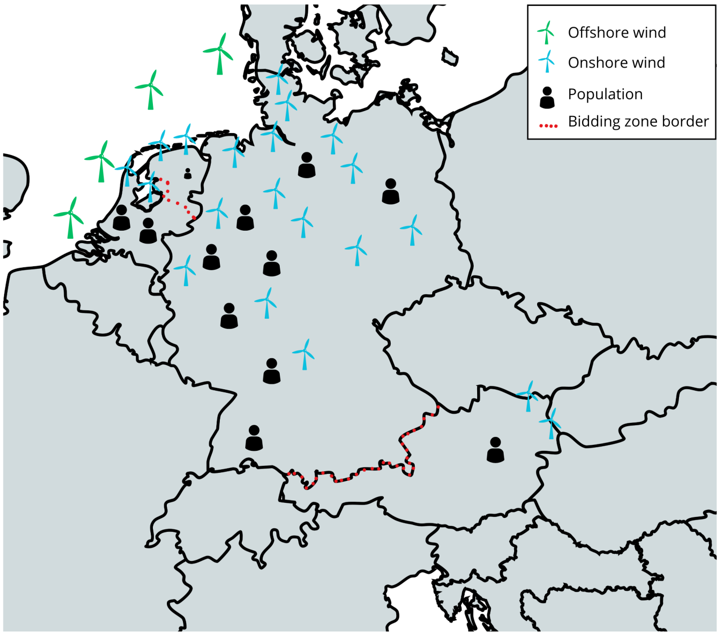


Figure 2.9: Comparison of NL split and DE-AT split

3 Modeling

The next step of the research is to gain insights into the behavior of the market dynamics in Europe when a split in the Netherlands is made. To gain insights into this behavior, quantitative research is conducted to compare the situation before and after the split. This is done with electricity market modeling. In this chapter, the modeling approach and its results are presented. First, the process of choosing the modeling strategy is explained. Then, the model set-up is clarified, and certain assumptions are made in the reference model. The reference model is the 'starting' model provided by Eneco. Furthermore, the modeling methodology and used data are specified.

3.1. Modeling strategy

To answer the second sub-question, a method has to be found to model the Dutch bidding zone split with existing market data. First, the decision is made to use economic dispatch modeling. Economic dispatch modeling can be used to simulate the electricity market. By doing this simulation, electricity market dynamics and effects on electricity prices can be analyzed before and after implementing a policy measure, such as the bidding zone split. The impact of the bidding zone split can then be quantified.

In an economic dispatch (ED) problem, the cost of production is minimized while matching the demand for electricity with the available supply. The generators with the lowest marginal costs are turned on until the total demand is reached. This is done for every time step, optimizing the generation schedule. The power plant with the highest marginal cost has to be turned on to meet demand, and the demand with the lowest willingness to pay determines the market price. Based on Pfenninger and Lukszo (2022), in its standard form, the optimization problem will look like this:

$$\text{Minimize}\, C(P_G) = \sum_{i=1}^{n} C_i * P_{Gi} \tag{3.1}$$

$$s.t. \qquad \sum_{i=1}^{n} P_{Gi} = D \tag{3.2}$$

$$and \qquad P_{Gi,\text{min}} \leq P_{Gi} \leq P_{Gi,\text{max}} \tag{3.3}$$

In Equation (3.1), the objective function is presented, where C_i is the cost of the generator and $P_G i$ is the respective output. This is then constrained by Equation (3.2) by making the generation output equal to the demand and by Equation (3.3), which sets the output restrictions of the power plant. This maximum value can be the maximum capacity or a specific maximum operational restriction. The minimum value can be zero or any minimum operational restriction assigned. Finding the solution to this problem will give the optimal output cost-wise. This problem is a linear programming problem.

In zonal pricing, a price for every zone is set, and generation is optimized while dependent on demand and the net position of the zone. The net position of the zone describes how much electricity is imported or exported. The first three equations that were presented are now slightly expanded to adhere to a zonal configuration. The equations for this Economic Dispatch problem, based on Aravena et al. (2021), read as follows:

$$\text{Minimize}\, C(P_G) = \sum_{i \in G_z} C_i \cdot P_{Gi} \tag{3.4}$$

$$s.t. \qquad \sum_{i \in G_z} P_{Gi} = D_z + p_z, \quad \forall z \in Z, \quad \forall p \in P, \quad \sum_{z=1}^{Z} p_z = 0 \tag{3.5}$$

$$and \qquad P_{Gi,\text{min}} \leq P_{Gi} \leq P_{Gi,\text{max}} \tag{3.6}$$

In Equation (3.4), all generators in a certain zone z, are now included. This is then constrained by Equation (3.5) by making the generation P_{Gi} output equal to the demand D_z plus a certain net position p_z for every zone. This is the zonal power balance. Equation (3.6) sets the output restrictions of the power plant in the same way as before. Another important constraint is $\forall p \in P$. This ensures that the net positions p, lie in a feasible set P. It is defined differently for each interzonal capacity but always respects the power balance $\sum_{z=1}^{Z} p_z = 0$ (Aravena et al., 2021). P should make sure that all net position configurations that respect the grid and safety regulations are included.

A zonal market clearing model can be used to simulate the electricity dynamics in Europe. This will provide a means to numerically test a bidding zone split. All variables that were mentioned in the zonal market clearing equations have to be gathered. Demand data, generation data, cost functions, net positions, and additional power plant restrictions are needed as inputs for this modeling. To create a robust model, it is useful to compare the model to historical data. A zonal market clearing model will be created which models a large part of the EU. To validate the model, it is convenient to create a backcast. A backcast is a simulation of the past. It can also be used to say something about the future or be used as a validation to do a forecast. A backcast can use existing market data. First, a backcast will be created to simulate the past in its current situation. The model can then be validated with historical data to check for any errors and establish its accuracy. This will be the situation before the split. Of course, the interest lies in splitting the Dutch bidding zone and its associated effects. So, the model will then be changed by applying a bidding zone split in the Netherlands. This will provide an insight into what the past prices would have been like with a split. This way of modeling does not cover all the impact that the bidding zone split will have, but it creates a way of comparing the old and new configurations.

When performing the split, some variables will remain the same. These fixed variables are the price of a generator, its maximum output, and the demand in a specific node or zone. Other variables, such as the zonal net positions and the optimal generators, will change. Of course, the generators and demand will be assigned to their new corresponding zones. This can be done quite straightforwardly. However, the new net position of the zones will change due to different power flow constraints. Where electricity first was assumed to flow freely through a large zone, it now has to deal with capacity allocation on the new cross-border. Modeling this variable has some complications. The transmission constraints and their changes are further explained in the next subsections.

3.1.1. New Flow-Based domain

The net position of a zone is vital information for market modeling. The net position of a zone has to lie in a feasible area, which is constrained by certain parameters. As explained in Chapter 2, this can be calculated with NTC or FBMC. Currently, FBMC is used in the Netherlands. The flow-based constraints are repeated:

$$\sum_{z} [\mathrm{PTDF}_{l,z}^{zon} \cdot NEX_z] \leq RAM_l \qquad \forall l \tag{3.7}$$

In Equation (3.7), the zonal PTDFs describe the relationship between the net positions and the flows through the critical lines (van den Bergh et al., 2015). The flows are restricted by the RAM. The zonal PTDFs for the CNEs and the RAM values are published by TSOs after the market clearing (JAO, n.d.). These can therefore be used to do a backcast. However these historical values cannot be used anymore once a split is performed, as they will change.

The critical network elements and their respective RAM and PTDF values constrain the flow-based domain. Let us look at the split's changes on the flow-based domain of the Netherlands and the other involved countries. To clarify this, the effect is visualized in Table 3.1.

CNE	From	To	Ptdf_Other	Ptdf_NL
1	Other	Other	...	...
2	Other	NL	...	...
3	NL	Other	...	...
4	NL	NL	...	...
5	?	?	...	...

Table 3.1: Example PTDF Matrix

This table is a basic visualization of which PTDFs would be impacted. The critical network elements change for every time period (in the case of day-ahead market coupling it is published hourly). All network elements that have an impact on transmission limits in the CORE region are identified by the TSOs. These are the critical network elements. The limits that are caused by these CNEs on the net position of the coupled zones in the CORE region are calculated by the zonal PTDFs and the RAM. The PTDF value in the zonal PTDF matrix gives information about the fraction of the power that goes into the zone because of this CNE. This means that CNEs in another country can have an effect on the net position of the Netherlands. In the same way, CNEs that go from another country to the Netherlands, or internally in the Netherlands, can have an impact on the allowed net position of other countries or on the Netherlands itself.

In Table 3.1, the PTDF matrix is visualized. In the first column, the critical network elements are numbered. There are CNEs inside the Netherlands, so going from NL to NL. Furthermore, all cross-zonal elements are per definition critical network elements. They go from NL to 'Other' or from 'Other' to 'NL'. Then there are critical network elements outside of the Netherlands. The last ones can still affect flows in the Netherlands. For every CNE, a PTDF value for every bidding zone is present in the PTDF matrix. Because of the split, the PTDFs will be affected, as the NL zone now consists of two zones. The PTDFs that the Netherlands will impact are colored red. It is not clear what these new PTDFs will look like. This can only be known by Tennet, the Dutch TSO. The Dutch TSO publishes information concerning the CNEs, zonal PTDFs, and reference flows after market clearing. However, it does not release any information on how they calculate this or in what way the CNEs are uncovered. This makes it difficult for other parties to do forecasting.

3.1.2. Exact projection

Splitting this zone will change the PTDFs and thus the flow-based domains, so existing PTDF and RAM data can not be used to predict the market behavior after a split. The new PTDFs and RAM are unknown and cannot be calculated. To tackle this problem, the modeling strategy of using Exact Projection is now introduced.

In their research Aravena et al. (2021) propose a mathematical method called Exact Projection, which discards approximate power flow calculations by using actual grid constraints in their calculations for power flows. The feasible area of net positions is now not approximated with PTDFs and RAMs, but exactly calculated with actual grid constraints. First, the same objective for zonal market clearing is used. This is the same objective as Equation (3.4), and with the same constraints in Equation (3.5) and (3.6). To repeat: $\forall p \in P$. This ensures that the net positions p, lie in a feasible set P. The exact set of feasible net positions can be calculated instead of approximated by power flows. To incorporate all actual grid constraints, the power flow equations are projected onto the space of net positions (Aravena et al., 2021) like this:

$$\sum_{g\in G(z)} Q_g \bar{v}_g - p_z = \sum_{n\in N(z)} Q_n \quad \forall z \in Z, \tag{3.8}$$

$$\sum_{g\in G(n)} Q_g \bar{v'}_g - \sum_{l\in L(n,\cdot)} f_l + \sum_{l\in L(\cdot,n)} f_l = Q_n \quad \forall n \in N, \tag{3.9}$$

$$-F_l \leq f_l \leq F_l, \quad f_l = B_l(\theta_{m(l)} - \theta_{n(l)}) \quad \forall l \in L. \tag{3.10}$$

These equations are used to define the feasible set P. They are used next to the objective function. Equation (3.8), makes sure that the sum of the accepted generation, noted by the quantity bid Q_g, and the acceptance decision for the bid indicated by $\bar{v}_g$ minus the net position of the zone p_z, equals the total demand in the zone Q_n. This holds for all zones in the system.

Equation (3.9), makes sure that the sum of generation accepted at a certain node, minus the net outflow $f_l(n,\cdot)$ plus the net inflow $f_l(\cdot,n)$ equals the demand at a node.

In the last equation, which is Equation (3.10), the constraints concerned with the electrical properties of a line are stated. The flow in a line f_l needs to adhere to the thermal limit F_l. Next to this, the susceptance of a line B_l and the voltage angle θ, model the direct current transmission constraints.

In other words, this method now allows all feasible trades to be cleared, respecting the network constraints. This exact projection provides an accurate representation of the network's capabilities. After initial market clearing, the actual physical constraints of the power grid are considered more accurately. The output of generators is changed by doing redispatch. This means that the initial market-clearing does not necessarily need to follow the physical market constraints, but there has to be a possible re-dispatch in the feasible domain restricted by the grid constraints. There are thus two generator output variables. One is for the market clearing, and the other is after redispatch. These are respectively, the variables $\bar{v}_g$ and $\bar{v'}_g$. So, there is a new variable for the output of each generator after redispatching.

3.1.3. Plexos software and Exact Projection difficulties

The modeling for this thesis is done with Plexos software. Plexos is an optimization software that allows the user to perform a market simulation and generate price forecasts (Energy Exemplar, n.d.) It is a tool that allows the user to add relationships between objects and has an option to add data files. Furthermore, it has numerous modeling options. This optimization software was chosen as it is Eneco's current optimization software. Using the software provides the advantage of building onto an already existing model and using already known input data.

Difficulties in using the Exact Projection (EP) method arose during the modeling process. Due to the setup of the software, the author did not deem it possible to continue with the EP method. First of all, in the transmission settings of the model, a choice has to be made between a zonal market clearing and a nodal market clearing. When doing a zonal market clearing, all nodal transmission properties are ignored. Furthermore, differentiation in nodal demand and generation is grouped and not distinguished. When doing a nodal market clearing, the market is cleared for every node separately. A middle way, which is necessary for the EP, is unavailable. When generating a zonal price with nodal constraints, Plexos does provide an output for the zonal price. However, this zonal price is based on weighted averages of the nodal prices by their load. This does not give the desired result. The second problem was the two stages of this modeling method. Plexus offers some redispatch modeling options. However, the process that EP uses, to ensure the feasibility of the net positions while not immediately constraining them into the initial market clearing, but having them constrained after redispatch, is hard to implement. This is not supported by Plexos built-in settings. Plexos does offer custom Python and Matlab plug-in options. Another way to fix this would be pre-processing or post-processing steps, combined with the Plexos software. Due to the time limit of this research and the complications of this method, it was decided not to pursue these alternative routes.

3.1.4. Practical approach

A practical modeling approach replaces the EP method. In this approach, the effects of changing cross-border transmission capacity are explored with NTC values. So, there is a fixed transmission capacity for every cross-border between the Dutch zones themselves and between the Dutch zones and their neighboring zones. Instead of exactly calculating the transmission capacity between the Netherlands and its neighboring zones and between the new Dutch bidding zones, an estimated capacity is used to model the problem. The cross-border transmission capacity not directly connected to the Netherlands is assumed to remain unchanged in this setup. Literature is consulted to provide a realistic estimation of the new cross-border commercial capacity going to the new zones. The report of ACER (2024) has provided an overview of current cross-zonal trade transmission capacities. The average margin available for cross-zonal trade in critical network elements in the Netherlands was 36% in 2022 and 39% in 2023 (ACER, 2024). To further establish realistic transmission capacities, the assessment of available cross-zonal capacity for the Netherlands published by Tennet is used (Tennet, 2024). In this report, Tennet finds that transmission capacity margins between the Netherlands and Denmark and between the Netherlands and Norway remain above 70% for 99% of the time in 2023. Tennet also identifies critical network elements with a low transmission margin inside the Netherlands and between the Netherlands and the CORE countries (Germany and Belgium). This will assist in estimating transmission capacity input realistically. These transmission capacities cannot be assumed to be true, as they will likely change after a bidding zone split and also depend on the year or season. However, they do provide an insight into realistic estimations of the effects of the split.

ENTSOE data is analyzed to investigate the available commercial transmission capacity further. The forecasted transfer capacities of 2022 are evaluated for every connection to the Netherlands. This data is coming from the ENTSOE (n.d.-b). It is based on NTC calculation, so this data does give a conservative estimation. A histogram is created for every connected bidding zone, both for import and export. These histograms are displayed in Appendix A. The Direct Current lines are highly available, mostly scoring between 90% and 100%. Only in Norway do there seem to have been many outages in 2022. The connections to Great Britain and Denmark are highly available. This is in line with the findings from ACER (2024). The transmission capacity going to Germany and Belgium is very low, a little below 20%. As was said before, these are based on NTC calculations, so they are a little more conservative than the actual available transmission capacity. This might explain why they are lower than ACER (2024) has presented. Figure 3.1 shows where the new NL zones will be connected to provide a clear view of where these cross-zonal capacities lie. The red arrows show the corresponding zone with which the NL zones trade. There is also an arrow for the trade between the new NL zones. The arrow to Germany is displayed twice to show that the north and south zones have connections to Germany. All these cross-border capacities will be assigned an NTC value to create a realistic model for the bidding zone split.

3.2. Model set-up

In this section, the model's setup is explained. First, the reference model is described, which is the starting point of this research's modeling. Second, the model verification steps are explained. Thereafter, the model experiments and the data input needed for them are explained in detail.

3.2.1. Reference model

The model that is used for this research is developed based on a reference model provided by Eneco. In this reference model, a large part of Europe is modeled. Figure 3.2 shows the regions modeled in the reference model. Denmark, Italy, Norway and Sweden are split into their corresponding zones. The thermal limit of the lines limits the interconnection capacity modeled between all zones. All generators are modeled separately and are assigned to their corresponding zones. They have properties such as maximum capacity, downtime, repair time, etc. The renewable energy plants based on solar, wind, and biomass have an estimated realized output per zone. It is not explicitly modeled in Plexos with capacity factors and weather data. Historic demand, fuel prices and emission prices are also set up as input. The model can be set up to do a backcast, so it is a simulation of the past. This model uses a zonal market clearing. Equations (3.4), (3.5) and (3.6) show this zonal market clearing.

A zonal clearing is done, where supply must be balanced with demand and a certain net position. There

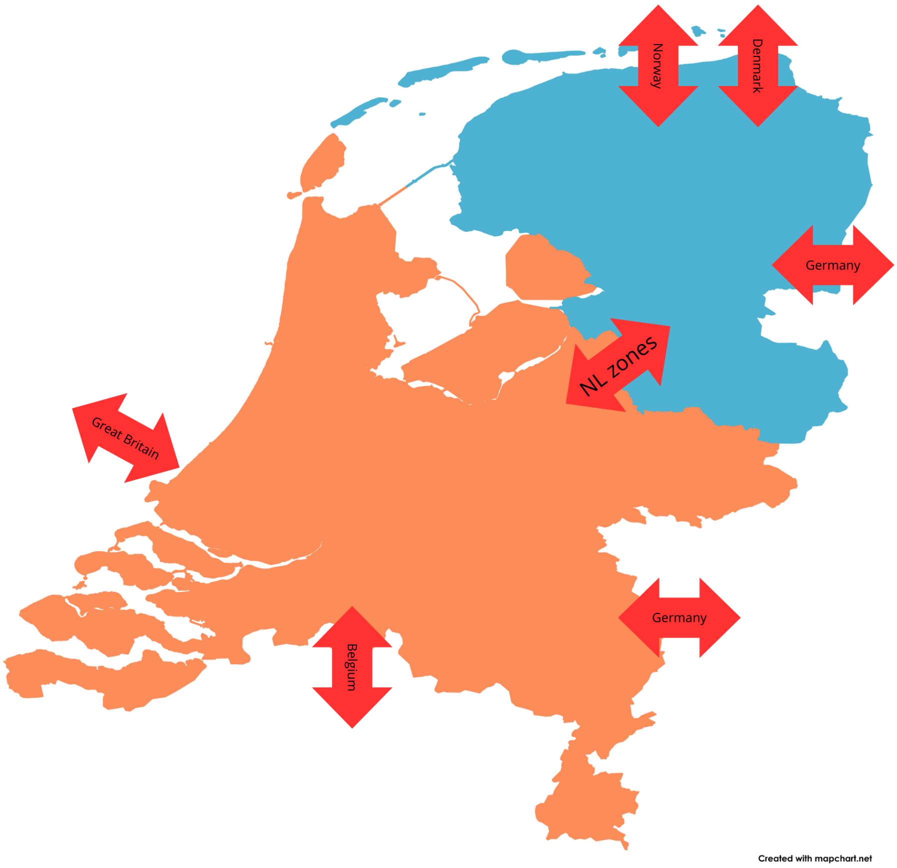


Figure 3.1: Map for NTC values practical approach

has to be a power balance. The sum of all net positions across all zones must be zero so that the total power imported matches the total power exported. Furthermore, the net position must lie in a feasible domain, which is defined by P. The feasible domain consists of all possible power flows that satisfy the transmission constraints. These transmission constraints are the power balance in a zone, the power balance of all zones together and the limits of the transmission between zones. The transmission limit between two zones can be modeled in different ways. In Chapter 2, it was explained that the coupled zones in Europe use NTC or FBMC to calculate this transmission capacity. However, in this reference model, the full thermal limit is used. Electric properties such as susceptance and phase angles are not defined. A minimum and maximum flow like this thus limits transmission in a line:

$$-F_l^{\max} \leq f_l \leq F_l^{\max} \tag{3.11}$$

In this reference model, the total thermal limit of the transmission line is taken as a minimum and maximum flow. In reality, this is not the case, as the thermal limit is not fully available for commercial transactions. Furthermore, all generators are modeled separately and have their specific properties. Firstly, they have a certain maximum capacity, which constraints the generator's maximum output, as shown in Equation (eq:z2). Other properties added to these generators are the fuel and emission costs, which are included in the cost function of a generator. Furthermore, the simulator can model random outages and planned outages. This is done by adding the following properties: the forced outage rate, the maintenance rate, the maintenance frequency, and the minimum, maximum and mean time to repair. These are included in the simulation, and based on these properties, generators have 'random' outages, which are included in the operational scheduling. The specific nuclear outages known from historical data are only added for France.

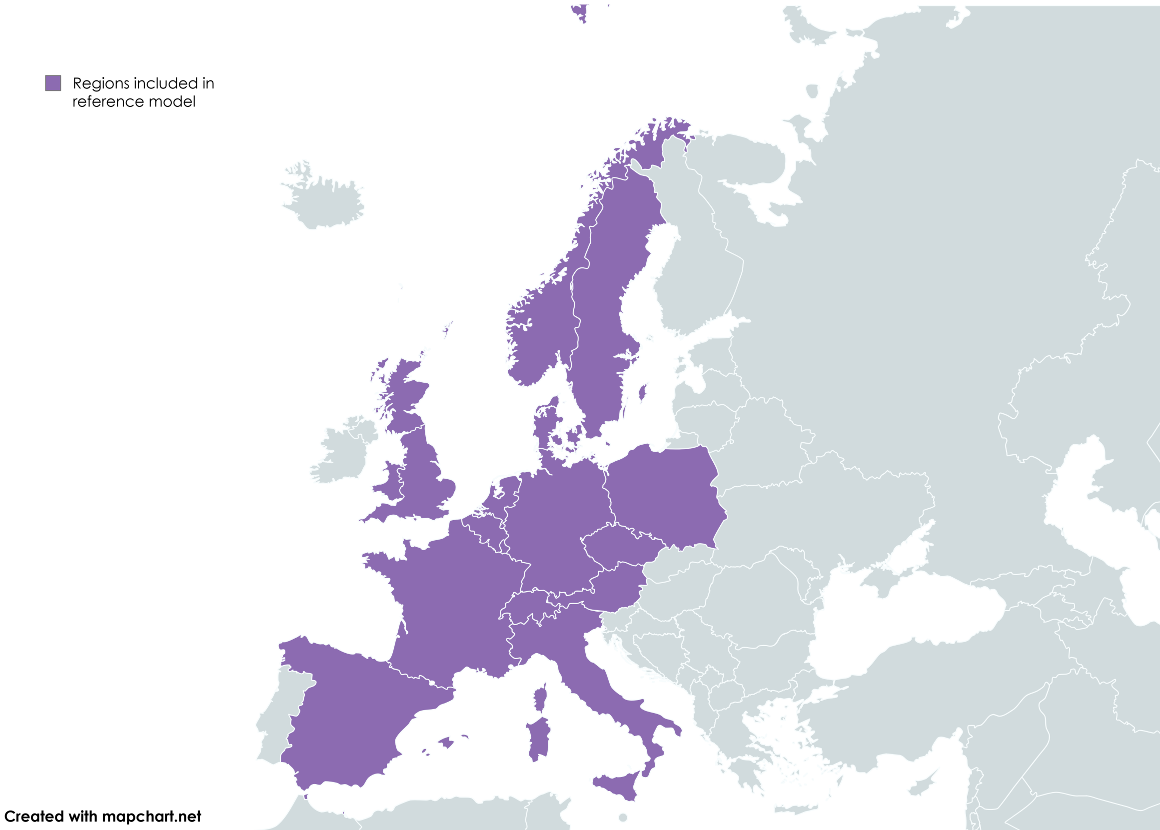


Figure 3.2: Regions included in the reference model

3.2.2. Model verification

In the testing phase of improving the reference model, it was noticed that there was a significant gap between the backcast day-ahead prices and the realized day-ahead prices sourced from the ENTSOE Transparency Platform (ENTSOE, n.d.-b). Numerous properties were evaluated to check the performance of the model.

First, to improve the model and create a better matching representation, the fuel price and ETS input were evaluated by comparing them to a different source. The prices were compared to prices from Yahoo! Finance (n.d.). The prices were comparable and thus did not change. Furthermore, the LP was questioned, as it simplifies the model. However, interpreting prices from a MILP model is not as straightforward as from an LP model. In the LP model, dual variables are directly used to obtain shadow prices (Pfenninger and Lukszo, 2022). The marginal cost of increasing production can then be determined, and thus, the price can be set. However, the market clearing price can not be directly computed when binary variables are considered. Additional post-processing steps are needed (Pfenninger and Lukszo, 2022). This is why it was decided not to change the LP problem to an MILP problem.

Some possible other causes for the gap between historical data and the reference model were discussed in conversations with the Eneco modeling team. They suggested it could be outdated plant property information, which could influence the plant stack. Furthermore, the renewable data from Volue (n.d.) is based on a modeled output, not an actual realized output. Lastly, market players do not always act precisely as optimization modeling tells them to. A plant owner may not see the advantage in turning on their power plant for a minimal earning price. In contrast, in an optimization problem, the plant will run when necessary for optimizing social welfare.

One crucial aspect that has been changed in the reference model is the available inter-zonal transmission capacity. In the reference model, the inter-zonal transmission capacity is defined as the total thermal limit. In reality, this full capacity is not commercially available. This available transmission capacity is changed by applying the transmission constraints that are now used in the coupled European zones. This is done with FBMC for CORE countries and NTC for non-CORE countries.

3.3. Model experiments

In this section, the three different models that were created based on the reference model are explained. The first model changes the reference model to a more accurate display by changing the thermal limit to a transmission limit based on FBMC and NTC. The second model is used to do a nodal analysis of the Netherlands by modeling the NL zone nodally. The third model is used to do experiments on a potential split in the Netherlands with the practical approach.

3.3.1. Model 1: FBMC and NTC transmission limits

In Chapter 2, the relevance of using FBMC and NTC have been explained, as well as their differences. The first modeling step is to implement the FBMC and NTC capacity calculations into the reference model. As these are the current ways of capacity calculation methods in the coupled European countries the model is supposed to be more accurate when validated with historical data. This can be done by replacing the transmission constraint which is currently set on the cross-borders which is only based on the thermal limit. The transmission lines between all NTC zones and connecting NTC zones to FBMC zones are limited with the NTC transmission limit. This NTC value is different depending on the direction of the flow. For a line between zone A and zone B, this will be modeled like this:

$$-NTC_{BA} \leq F_{AB} \leq NTC_{AB} \tag{3.12}$$

Next, the flow-based domain coupling has to be integrated into the model. This is implemented in Plexos as well. For every CNE the flow-based constraints look like this, based on Schönheit et al. (2021):

$$RAM \geq \sum_{z \in Z^{FB}} [\mathrm{PTDF}_{l,z}^{zon} \cdot NEX_z] \tag{3.13}$$

Every CNE is restricted by the RAM. Furthermore, the PTDF is a coefficient that describes the change in the flow when injecting a flow in a zone. So every zone has a PTDF value on every CNE. This is visualized in Table 3.2. Note that the PTDFs change for every time step. The market is now again cleared zonally but with these new transmission constraints.

CNE	AT	BE	FR	CZ	DE	NL	PL
Element 1	PTDF1,AT	PTDF1,BE	PTDF1,FR	PTDF1,CZ	PTDF1,DE	PTDF1,NL	PTDF1,PL
Element 2	PTDF2,AT	PTDF2,BE	PTDF2,FR	PTDF2,CZ	PTDF2,DE	PTDF2,NL	PTDF2,PL
Element 3	PTDF3,AT	PTDF3,BE	PTDF3,FR	PTDF3,CZ	PTDF3,DE	PTDF3,NL	PTDF3,PL
Element 4	PTDF4,AT	PTDF4,BE	PTDF4,FR	PTDF4,CZ	PTDF4,DE	PTDF4,NL	PTDF4,PL
Element 5	PTDF5,AT	PTDF5,BE	PTDF5,FR	PTDF5,CZ	PTDF5,DE	PTDF5,NL	PTDF5,PL
...	...	...	...	...	...	...	...
Element n	PTDFn,AT	PTDFn,BE	PTDFn,FR	PTDFn,CZ	PTDFn,DE	PTDFn,NL	PTDF,PL

Table 3.2: Zonal PTDF values example

3.3.2. Model 2: Nodal model of the Netherlands

In the reference model, the Netherlands is modeled as one node. A nodal model is created to analyze the layout and behavior of the Netherlands more deeply. The rest of the zones are still modeled in the same way as in the previous model. A nodal model has a power balance for every node, as was described in Chapter 2. A locational marginal price is calculated for every node. The equations are as follows:

$$\text{Minimize } C(P_n) = \sum_{i \in G_z} C_i \cdot P_{Gi} \tag{3.14}$$

$$s.t. \qquad \sum_{i \in G_n} P_{Gi} - \sum_{l \in L(n,\cdot)} f_l + \sum_{l \in L(\cdot,n)} f_l = D_n, \quad \forall n \in N, \tag{3.15}$$

$$and \quad -F_l \leq f_l \leq F_l, \quad f_l = B_l(\theta_{m(l)} - \theta_{n(l)}) \quad \forall l \in L \tag{3.16}$$

The equations look similar to the zonal clearing equations but are now based on nodes. So the price at a node is minimized, and the power flow has to be balanced for every node. For this first part, the nodal demand and nodal generation need to be known. For the second part, the electrical properties of all transmission lines are needed. The susceptance, reactance, resistance, and thermal limit are provided for every NL line. Next to this, the associated properties with specific generators that were discussed in the reference model remain the same. A node is created for every substation. The nodes are modeled with their assigned geographical coordinates and are connected with the corresponding transmission lines. The FBMC and NTC values with which the transmission lines going from the Netherlands to its neighboring countries are taken away. They are replaced by the nodal transmission lines and their respective properties.

3.3.3. Model 3: Split scenarios

In this next model, a split of the Dutch bidding zone is simulated. This is done by grouping the nodes into two different zones. Then, a zonal market clearing is performed. The demand is thus split into two zones, according to which node they belong. The same holds for the generators. The rest of the model is again modeled zonally, as done in the first model. Again, the transmission lines that connect the Netherlands are not modeled with FBMC and NTC values, as they have now changed. The exact new limits on these lines can not be calculated exactly. As discussed in the modeling approach, a practical approach with fixed NTC values will be used. Different scenarios are modeled to investigate the effect of the transmission capacity on the flows and the day-ahead prices. In the modeling strategy, the realistic percentages of the commercially available transmission capacities were already explained. The new lines inside the Netherlands, which used to be internal lines, are hard to predict and, therefore, tested with a range of percentages. The scenarios are designed to create a realistic image of possible outcomes after the split, with its associated prices and cross-border trades. The available transmission capacity assigned to the cross-border lines is expressed as a percentage of the thermal limit.

Nine scenarios are created to explore the effect of changing transmission capacities and to approximate the realistic values that are obtained from literature. First, experiments considering a very conservative transmission capacity for all cross-borders will be executed. This transmission capacity is enlarged in steps of 10%. Furthermore, experiments will be executed that contain different availabilities for exchanges between the new NL zones, exchanges going to Belgium and Germany and exchanges to the NTC zones.

The first models are limited with 10% 20%, 30% and 40% of the thermal limit as their available transmission capacity for all cross-border lines. This is thus the case for all connections between the Netherlands and its neighboring countries, as well as between the two new zones of the Netherlands. This is a very conservative scenario. Another experiment was conducted by changing the transmission capacity inside the NL zone. This experiment is performed to see the effect of higher transmission capacity between the two new NL zones. Lastly, an experiment that differentiates DC cables was conducted. This is mostly in line with the transmission availabilities that are now known. For the availability inside the Netherlands, the goal of 70% and a conservative 30% are chosen.

To be clear, all the investigated scenarios are shown in Table 3.3 . Three types of transmission lines are distinguished. The High Voltage Direct Current (HVDC) lines connect the Netherlands to Great Britain, Norway and Denmark. The new 'internal' lines connect the north of the Netherlands to the south of the Netherlands. Finally, the High Voltage Alternating Current (HVAC) lines connect the Netherlands to Germany and Belgium. Another example is shown by illustrating the specific available transmission capacities for scenario nine, Figure 3.3.

Scenario	1	2	3	4	5	6	7	8	9
HVDC	10%	20%	30%	40%	20%	20%	20%	90%	90%
Internal lines NL	10%	20%	30%	40%	30%	40%	50%	30%	70%
HVAC	10%	20%	30%	40%	20%	20%	20%	20%	20%

Table 3.3: Scenarios

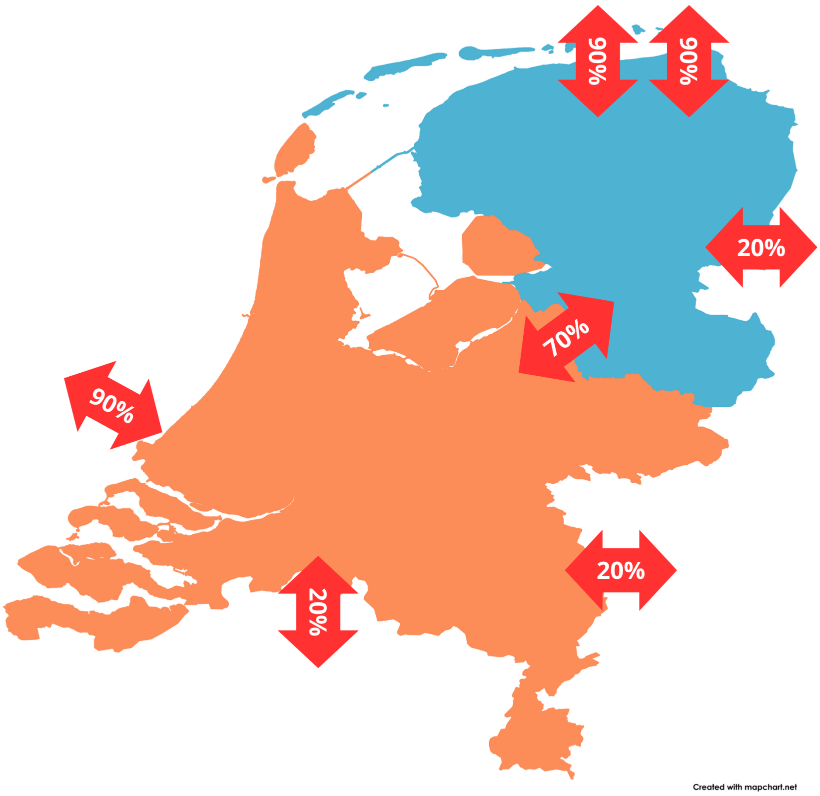


Figure 3.3: Example scenario nine

3.4. Model data input and specifics

This section explains the specific data input used for these three models. First, the selected time period is explained. Next, all three model set-ups are detailed.

3.4.1. Time period

All models do a backcast. So, a model is created that simulates power optimization from the past. With this backcasting, the past situation 'as it is now' is compared to the past situation 'to be' with a split. In this way, one can investigate what type of effects this split would have had. Another reason for doing a backcast is that past FBMC data (PTDF and RAM values) and past NTC data can be used.

The time period that is selected for this research is September-December of 2022. FBMC in the CORE region went live in June of 2022. The JAO publication tool, which is used to obtain the PTDF and RAM data, does not show any published data on this topic before September 2022. Because of the need for PTDF and RAM data, only the period after this can be used for the research. Furthermore, the reference model has faulty demand data in the year 2023. So, 2023 was not taken into account. Another aspect to keep in mind for the modeling is the computational time. In the testing phase, it was discovered that the reference model already took about 9 hours to run on a time period of 4 months. Because of these three reasons, the time period evaluated for this research is September-December of 2022. The day-ahead prices of the Netherlands in this period are displayed in Figure 3.4. It can be observed that electricity prices were relatively high and had a large price volatility. The investigated time period is divided into steps of an hourly resolution according to the start and end date in Table 3.4. This leaves 2928 time steps (122 days x 24 hours).

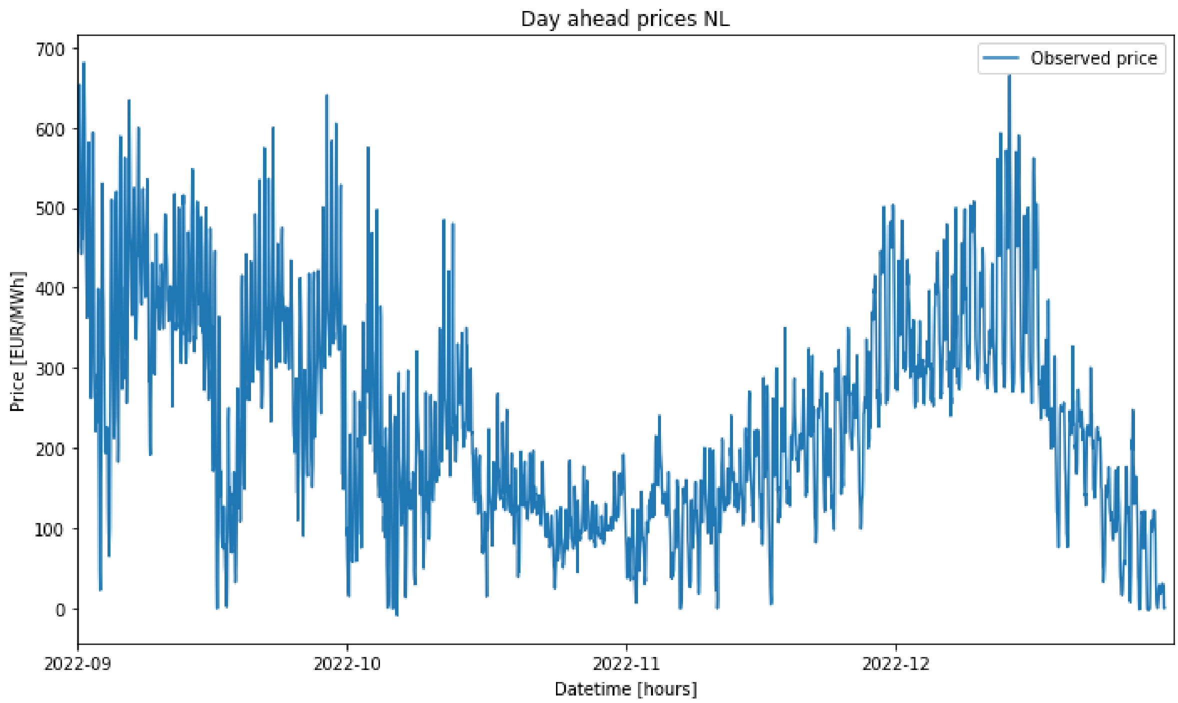


Figure 3.4: Observed prices September - December 2022

	mm/dd/yyyy	hh:mm:ss AM/PM
Startdate:	9/1/2022	12:00:00 AM
Enddate:	12/31/2022	11:00:00 PM
Total time:	122 days	2928 hours

Table 3.4: Evaluated period

3.4.2. Data model 1: FBMC and NTC

For model 1, the NTC values and the FBMC data for every time step are needed as input. The concerned CNEs and their respective PTDF positions and RAM values were found on the JAO publication tool (JAO, n.d.), where much network information is published. FBMC calculation was applied to Austria, Belgium, the Czech Republic, Germany, France, the Netherlands, and Poland. The other CORE countries are not included in this model. For the remaining countries that use NTC, data is taken from the ENTSOE transparency platform (ENTSOE, n.d.-b). For the NTC values, day-ahead calculations were not provided for all countries. For some of them, only week-ahead calculations were available. The overview of the data input can be found in Appendix B .

3.4.3. Data model 2: Nodal model

Network information is extracted from the Static Grid Model (JAO, 2023). The Static Grid Model holds information about grid elements of the CORE TSOs and their corresponding electrical properties (susceptance, reactance and resistance). According to Tufon et al. (2009), transmission line capacity is limited by thermal capability, voltage support or stability concerns, depending on the length of the line. The longest analyzed transmission line, in this case, is 107 km. For lines shorter than 160 km, the line capacity is limited by thermal capability. Thermal capability can be calculated with this equation, based on Rashid (2016):

$$P_{max} = \sqrt{3} \cdot V \cdot I \tag{3.17}$$

where P_{max} is the maximum power limit in VA, V is the Voltage, and I is the maximum current. The maximum current values of a transmission line published by JAO (2023) are distinguished into two categories. One value for the summer and one for the winter are provided. This is because there is a dynamic line rating. The maximum allowed current in a transmission line can be higher or lower depending on the temperature or wind speed that cools the transmission lines. Therefore, the maximum allowable current is lower in summer to prevent overheating. As the period evaluated in this research covers both summer and winter, the limit is split into two periods, according to the assumptions of JAO. They define September and October as summer months and November and December as winter months. This is assigned accordingly for the lines with a published dynamic line rating. In Figure 3.5, the substations and the transmission lines as modeled in Plexos can be seen.

Next to the substations and transmission lines, the power production and demand must also be modeled nodally. Let us first look at the demand side. In the reference model, the demand of the Netherlands is centered at one single node. This demand is available at an hourly level. No source that explicitly publishes demand data on a nodal level is available to the author. The demand input from Volue (n.d.) is therefore scaled with a certain factor and divided over all nodes. This factor is based on population density and the Gross domestic product (GDP) per NUTS3 area. NUTS3 are regional areas that divide the Netherlands into 40 regions and are commonly used in statistics. The population size per NUTS3 area in 2022 was extracted from CBS (CBS, n.d.). Next, the GDP per NUTS3 area was sourced from Eurostat (Eurostat, n.d.). For this information, only data from 2020 was found. These two values were multiplied and normalized, resulting in a factor for every NUTS3 area. This factor is then assigned to the substation in the area. If there is more than one substation in the area, the factor is evenly divided over the substations. If the NUTS3 area does not contain any substation, the factor of the area is added to the closest area. These factors can now estimate the nodal demand at every substation.

The supply side also has to be modeled in a nodal way. In the reference model, the fossil power plants are all modeled separately and contain geographical information. The power plants are matched to the nearest node and then assigned. For the renewable plants, an extra calculation step needs to be taken. For renewable energy coming from wind and solar, the output of the generators depends on weather data. As this is a simulation of the past, the realized output of these plants is known. In the reference model, this input is modeled through synthetic values, which predict the realized power output according to weather data. This output is available at an hourly level. This is again based on the Netherlands as one node. This forecasted data coming from the reference model is again used in this model, but the values of this predicted realized output are scaled with a certain factor. This factor is calculated based on the installed capacity and then normalized. The locations of the solar, onshore and offshore wind plants are determined and then assigned to the nearest node. The locations are determined with

Figure 3.5: Plexos nodal model

Open infrastructure Map (n.d.). For the offshore wind parks, the substation that connects the offshore transmission lines to the grid is matched. The renewable data is now distributed nodally.

3.4.4. Data model 3: Split scenarios

The split of the Netherlands that is modeled in this research is based on the decision for new bidding zone configurations made by ACER (2022). This split can be seen in Fig 3.6. By using LMP calculations from the TSOs, ACER has performed several clustering techniques to group nodes with a high price convergence together. Next to this, TSOs were involved in deciding efficient zone split configurations by providing their input. Other energy stakeholders also provided their feedback as input for the configuration. This led to an alternative configuration proposal for five EU countries. Regarding the Netherlands, it was decided to split the bidding zone into two. The border of this split roughly follows the borders of NL provinces. For this research, it is therefore assumed that Zone 1 consists of Groningen, Friesland, Drenthe and Overrijssel, and Zone 2 consists of the remaining provinces. The nodes in the model are then all assigned to 'NL-N' or 'NL-S'. The north zone is named NL-N and the south zone is named NL-S. As the generation and the demand are modeled nodally, they are automatically assigned to the right zone.

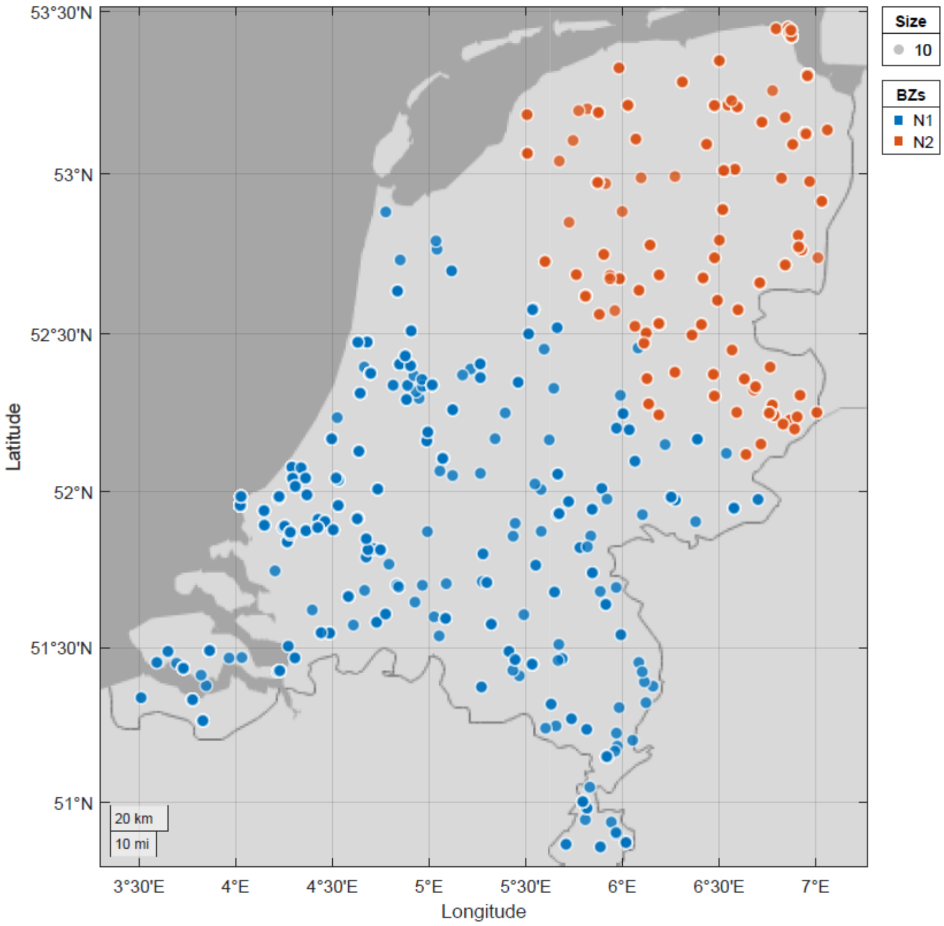


Figure 3.6: NL split proposed by ACER, sourced from: Tennet (2023)

4
Results and discussion

This Chapter presents the results of the different experiments. In this results section, the Netherlands is the center of the analysis. However, the effects on Austria, Belgium, Czech Republic, France, Germany and Poland are also evaluated to include interesting effects on the neighboring countries. First, the results of adding FBMC and NTC values to the basic model are presented. Then, it is analyzed whether there is an improvement in modeling results compared to historical data. Furthermore, the results of the nodal model are analyzed. Next, the different scenarios regarding the bidding zone split are evaluated.

4.1. Model 1: FBMC and NTC

The first modeling step was to improve the Eneco model by adding Flow-Based Market Coupling and Net Transfer Capacity. In the Eneco/basic model, transmission was based on the full thermal limit of a transmission line. As the capacity is rarely fully available, this causes too much electricity to be traded compared to historical data. The FBMC-NTC model is compared to the basic model. The model is also validated by comparing it to the observed day-ahead prices from ENTSOE.

In Table 4.1, the models are assigned a certain name. In the remainder of the results, these models will be referred to by these specific names.

Assigned name	**Model/data description**
entsoe	The observed historical values coming from the ENTSOE transparency platform.
basic	The ENECO model without alterations.
fbmc-ntc	The reference model which is expanded by including FBMC to the concerned CORE countries (Austria, Belgium, Czech Republic, Germany, France, The Netherlands and Poland) and NTC to the non-CORE countries.

Table 4.1: Overview of the tested models with their assigned names

To look into the effects of adding FBMC the Netherlands is evaluated first. It is also important to quantify the performance of the basic model. In Figure .., the simulation results of the Netherlands are compared to historical data. The orange line represents the backcast of the day-ahead prices of the basic model. The blue line shows the historical data from ENTSOE. The comparison shows a large deviation of prices. This is especially the case in the first 1.5 months when observed prices are very high, as well as in the beginning of December. The green line represents the model where FBMC and NTC data are used. It can be seen from the figure that this model performs better. The comparison of day-ahead prices of the other countries can be found in Appendix **??**. To investigate the difference more closely and see if there is a general improvement in forecasting, an analysis is done on the errors of the basic model and the FBMC-NTC model compared to the observed data.

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The in-depth error analysis is done for all previously mentioned 7 countries. For every country, a few statistical error metrics are assessed. First, the Mean Absolute Error (MAE) is calculated according to Jedox (n.d.):

$$MAE = \frac{1}{n}\sum_{t=1}^{t=n}|y' - y| \tag{4.1}$$

where n is the amount of samples, so in this case the amount of time steps, where y' is the forecasted value and y is the true value. In this case, the true value is the observed value from ENTSOE and the forecasted value is the predicted day ahead price by the 'basic' and 'fbmc-ntc' models. The MAE will show how large the error of the forecasting model is compared to historical data. A low MAE will thus mean that the results are accurate compared to the observed data. The RMSE is also calculated to give a good interpretation of the size of the errors. This metric gives a larger penalty to high errors because it squares the error first. The difference between the MAE and the RMSE indicates if there are outliers. Taking the root makes it easily comparable to the MAE because it is on the same scale. It is computed according to Jedox (n.d.):

$$RMSE = \sqrt{\frac{1}{n}\sum_{t=1}^{t=n}(y' - y)^2} \tag{4.2}$$

Lastly, the error outliers are also examined. Outliers are data points that deviate a lot from the majority of the data (Dekkin et al., 2005). They can be identified by calculating the lower and upper quartiles. The lower quartile is the line that divides the lowest 25% of the data to the rest of the data. The upper quartile is the line that divides the upper 25% of the data. The interquartile range (IQR) is the distance between the upper and lower quartiles Dekkin et al. (2005). They identify the outliers like this:

$$\text{outlier} = \text{error} < (q_n(0.25) - 1.5 \cdot IQR) \tag{4.3}$$

or

$$\text{outlier} = \text{error} > (q_n(0.75) - 1.5 \cdot IQR) \tag{4.4}$$

The outliers are presented as a percentage of the total data points. The MAE is also expressed as a percentage by dividing the MAE by the mean of the historical values. The MAE, MAE in percentage, RMSE and the identified outlines are provided for both models for every zone in Table ... Furthermore, the model's performance is classified based on the lowest MAE. There is one side note to state for the evaluation of France. There are some days in December when the model outputs an error. This could be because the demand could not be met based on all constraints in this model. There may be some constraints on France that are too strict. In reality, when prices go higher, there will also be a demand response. For example, factories that use a lot of electricity may stop running when the price exceeds a certain threshold. When an error is made, Plexos gives an output of 3000€/MWh. To give a better impression of the French electricity prices for the whole period, this output, as well as a corrected output, is provided. In the corrected output, the errors are set to 0€/MWh. These plots can both be found in Appendix **??**. The output of France is still stated in Table .., where all error entries are removed from the data set. This affected 97/2928 data points. These same data entries were removed for all zones.

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The net position of the Netherlands is also validated by comparing both the Basic and the FBMC-NTC models to historic values from ENTSOE. Figure .. plots the net position for the selected time period for all three models. It can be observed from this figure that there are quite some discrepancies between the basic model and the historical data. The FBMC-NTC model shows some improvement but is still far from the validation data. In September, the FBMC-NTC model seems to be even worse. Where in the historical data, the Netherlands is exporting, in the model it seems to be importing. An underestimation of renewables could explain this, as this mainly happens in September. Another explanation is the high price volatility in that month, which the model may not fully represent. The three models can be compared more easily in Figure ... This boxplot shows the difference between the historical data and the two models. As the FBMC-NTC model is more limited in import and export, it is logical that its boxplot has a smaller range compared to the Basic model, where the total thermal limit for all lines is used. The FBMC-NTC model still has significant errors in the net position.

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4.2. Model 2: Nodal model

In the nodal model, nodal behavior is evaluated. 45 nodes were modeled according to the available substations in the Netherlands. The prices and the load at the nodes are evaluated. Next to this, the transmission lines are analyzed to look for congestion. All prices for the nodes are calculated on an hourly basis. The median price for every node is calculated and is shown in the heat map in Figure 4.1. The exact median of all nodes can be found in Appendix C. It can be seen that the prices can roughly be divided into two groups. For one group, the median price lies around 223 €/MWh. For the other group, it lies around 199€/MWh. Two nodes are taken out and analyzed more deeply to take a closer look at these results. One node lies in the higher-priced group, and one node lies in the lower-priced group. The higher-priced nodes had some errors, where the output reached prices of 3000€, probably because the demand couldn't be met. The number of errors was 33/2928 data points and thus seen as negligible.

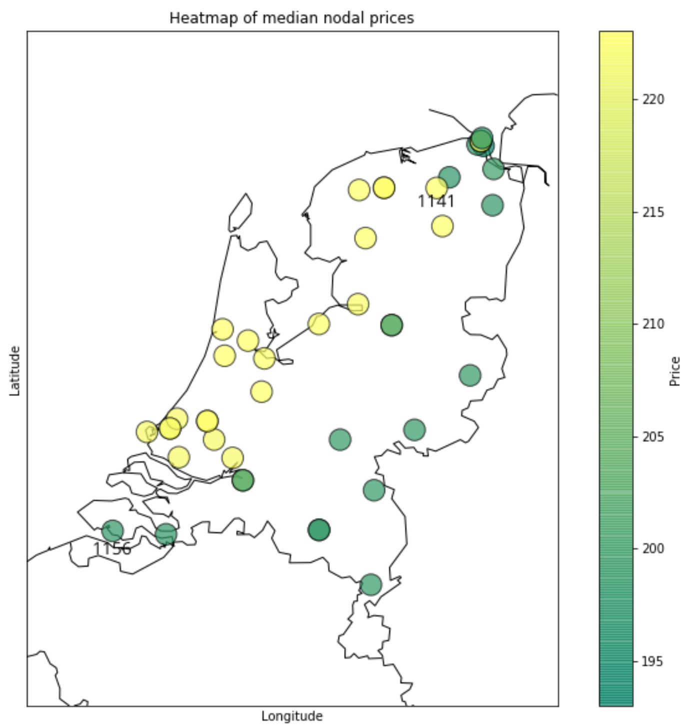

Figure 4.1: Heat map of median nodal prices

In Figure 4.2, the two nodes 1141 (node 1) and 1156 (node 2) are plotted for the examined time period. Next to this, Figure 4.3 shows a snapshot of the first two days of September. Node 1 shows higher prices, mostly in September but also throughout the year. It uses higher-priced electricity, especially during peak hours. The median prices in the west of the Netherlands seem to be higher than in the east and the south of the Netherlands. Some other properties are investigated to look for further explanations.

First, the power plants' distribution is evaluated to look for explanations. As explained in the Methodology, the power plants are assigned to the nearest node, so the location of these power plants does not exactly match reality. All generators that produced output in the nodal analysis are plotted on the map of the Netherlands. This can be observed in Figure 4.4. Solar and biomass plants are located throughout the country. Next, the offshore and onshore wind are located near the shore. The offshore wind is displayed located at the substation where its line is connected. In reality, the locations are further off coast. The fossil plants are mostly located in the country's west, with a few in other parts. Lastly, there is one nuclear plant in Zeeland. The location of the wind power plants should coincide with high electricity prices, but this is not the case here. There may be another reason for the high prices. It can be observed that there are a lot of fossil power plants located in the high price areas. Note that this map does not say anything about the size of the generated power.

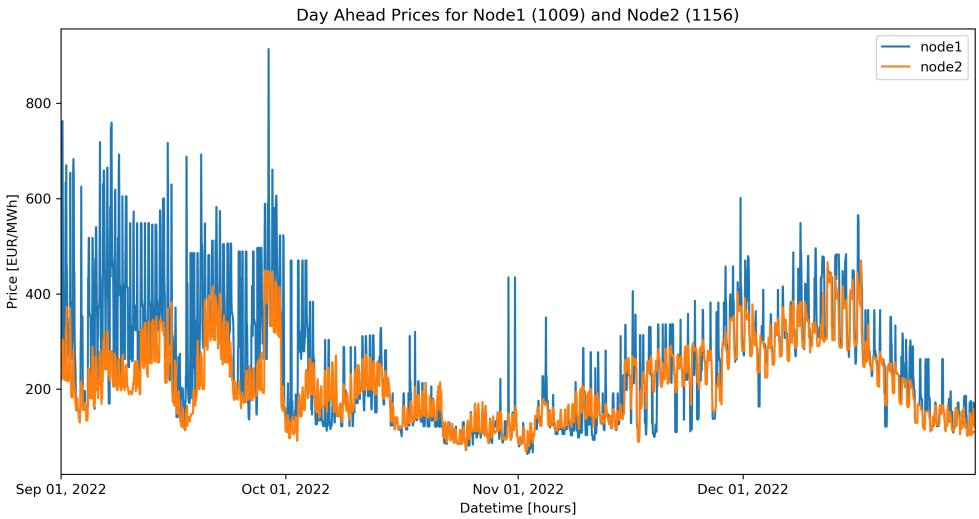

Figure 4.2: Day-ahead price comparison two nodes

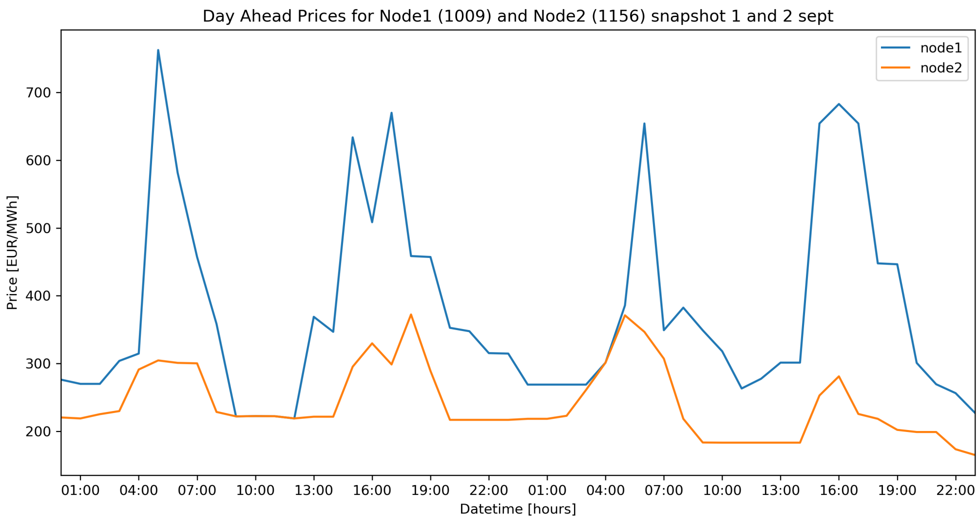

Figure 4.3: Day-ahead price comparison two nodes 2 days

Next, the load is analyzed. In Figure 4.5, the median load is plotted for all nodes. It can be seen that there is a larger load present in the center and the south of the Netherlands. This is probably due to

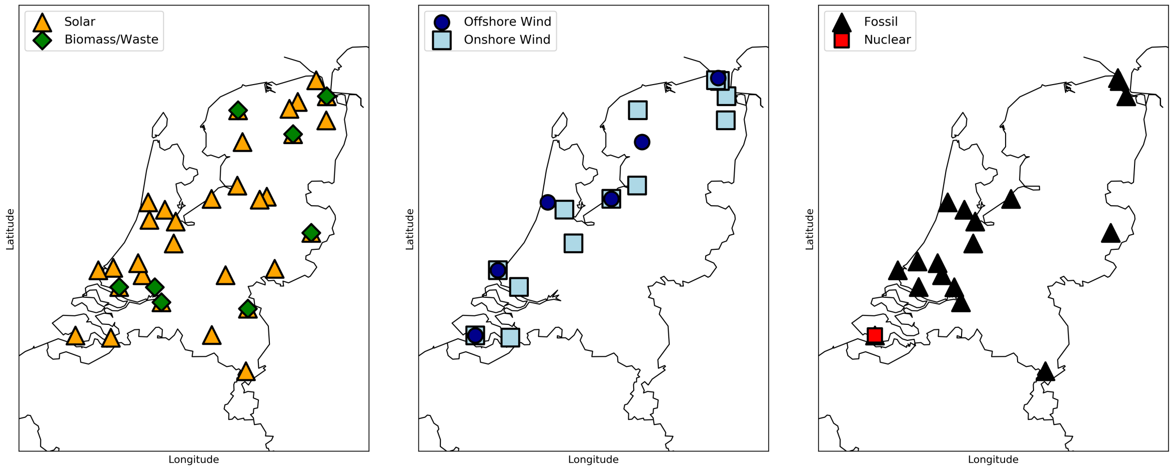

Figure 4.4: Distribution power plants

the higher population size and density of energy-intensive industries. The population density in the provinces of North and South Holland is the highest. This could explain part of the high nodal electricity prices, as there is a high demand. In the first map, which showed the high prices, some high-priced nodes in Friesland were still not explained.

Lastly, the transmission in the lines is evaluated. The congestion is measured by evaluating the percentage of time the thermal limit of a line is fully reached. This is displayed in Figure 4.6. In this nodal set-up, there is mostly congestion in the lines going to other countries, not in the Dutch zone itself. It makes sense that the DC lines going to Norway, Denmark, and Great Britain are fully used. Next, the transmission going to Belgium can also be pointed out. Remarkably, transmission to Germany, known to be congested, is not shown in this nodal analysis. However, it has to be stressed that this is an analysis based on a nodal clearing. Congestion in a zonal clearing will look different. Unfortunately, the setup of the zonal model prohibits any congestion analysis between zones. Looking further, there also seems to be some congestion in the north of the Netherlands. This could be because of the density of wind capacity or other power plants located here. An explanation for the congestion in the provinces of North and South Holland could be the high demand.

In this nodal analysis, it was discovered that nodal prices seem to form two groups, with higher prices in the west of the Netherlands. This differentiation does not align with ACER's proposed split, which divides Friesland, Groningen, Drenthe and Overijssel from the west of the Netherlands. In this nodal analysis, high prices were also found in Friesland. The choice for the proposed reconfiguration could also have depended on the geographical layout of the country and congestion patterns. Congestion patterns and the location of fossil power plants may explain the higher-priced nodes. This nodal analysis has also shown that most of the electricity demand is in the south of the Netherlands.

Lastly, the two previously analyzed nodes are compared to the zonal price established in experiment one. This is displayed in Figure ... This plot shows that node 1, which represents a similar price pattern to all identified higher-priced nodes, has higher prices than the NL zone. Next to this node 2 shows lower prices. The discrepancy between nodal and zonal prices is a sign of inefficiencies or potential problems in the market. The higher prices could mean that these are congested areas or areas with high demand. As discovered in the nodal analysis, these are congested areas or areas with high demand.

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4.3. Model 3: Split scenarios

In the final model, 9 scenarios are modeled to evaluate the impact of a changing trading domain of the new NL zones. As explained in the methodology, these scenarios are created based on numbers from ACER (2024) and Tennet (2024). From these sources, it was obtained that the HVDC

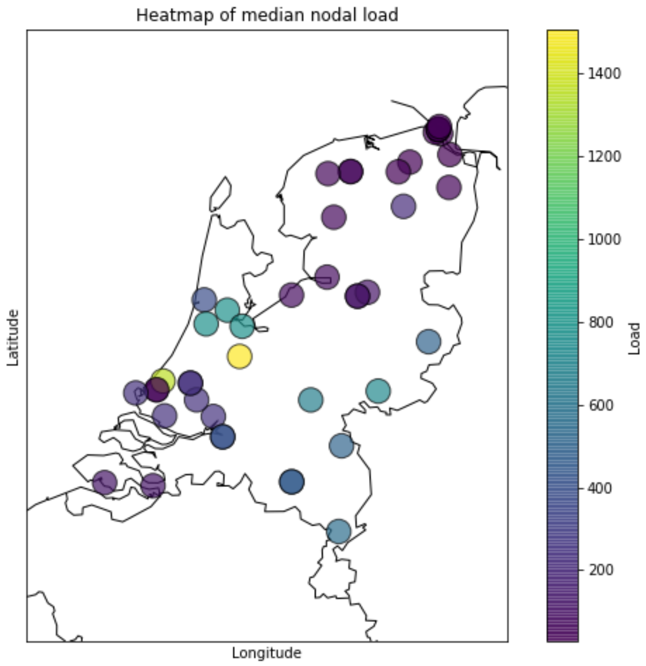

Figure 4.5: Heat map of median load

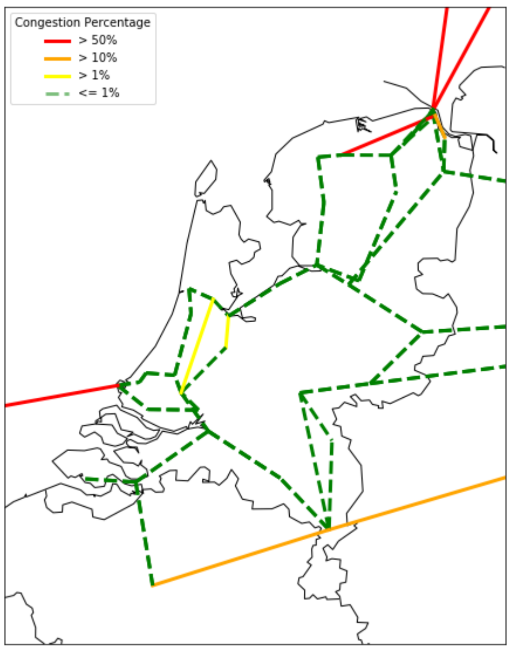

Figure 4.6: Nodal congestion

commercial transmission capacity is almost fully offered. Tennet (2024) published the numbers about the compliance of CNEs in the Netherlands to the mandatory 20% available transmission target. These CNEs influence the CORE countries. This report shows the target was reached exactly for 76% of the hours in 2023. So exactly 20%. A large part of the other hours had an availability up to 30%. This indicates that cross-border availability to Germany and Belgium ranges between 20% and 30% in 2023, with 2022 having even lower numbers. In the data gathered from ENTSOE (n.d.-b) it was even below 20%. However, this is based on conservative NTC values. This report also showed the impact of loop flows obstructing CNEs in the Netherlands.

This information has led to nine scenarios. The first four scenarios explore the impact of changing the transmission capacities for all cross-borders. The first scenario is a very conservative scenario, which is used to identify the effects of the model's setup. The scenarios will be compared to the situation before the split using FBMC modeling. It is important to distinguish the impact on prices because of the split versus because of not using FBMC. In scenarios 5-7, the effect on changing the transmission capacity between the NL zones is researched. The available transmission capacity between these new NL zones remains unknown. It is known, however, that CNEs in the Netherlands before the split had around 20%-30% available transmission capacity in 2023 (Tennet, 2024) and that they suffered from significant loop flows coming from Germany. Finally, scenarios 8 and 9 represent the situation closest to the expected capacities based on the literature. In scenario 8, the commercial transmission capacity between the NL zones is set to 30%, which is in line with existing CNEs in the Netherlands. In scenario 9, the commercial transmission capacity is based on the 70% goal set by the EU. The table with the set-up of the model is repeated for clarity in Table 4.2.

Scenario	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**
HVDC	10%	20%	30%	40%	20%	20%	20%	90%	90%
Internal lines NL	10%	20%	30%	40%	30%	40%	50%	30%	70%
HVAC	10%	20%	30%	40%	20%	20%	20%	20%	20%

Table 4.2: Scenarios

All scenarios models are run. The day-ahead prices and net position of the new NL zones are evaluated. Next to this, the day-ahead prices of the neighboring zones are evaluated. The scenarios are compared to the situation before the split, which was created in experiment 1 with FBMC-NTC. In Table 4.3, the average price for every scenario for the north NL zone and the south NL zone are displayed. This is the average price over all time steps. In this table, the price higher than the 'no split' price is colored red.

Scenario	**NL North [€/MWh]**	**NL South [€/MWh]**
No split	237.0	237.0
1	176.6	259.8
2	208.4	226.2
3	216.7	218.0
4	216.3	216.4
5	219.5	223.3
6	223.3	223.6
7	223.5	223.5
8	216.1	219.2
9	218.7	218.7

Table 4.3: Effect on average day-ahead prices for NL North and NL South

It can be observed that in all cases, the new NL zones experience lower prices. This could be a result of the split, but this could also result from the choice of available transmission capacity between NL and other countries. In the 'no split' case, this is calculated with FBMC, whereas in the split case, this is based on a set percentage. It seems strange that both zones profit from the zone split. When adding the additional constraint of capacity allocation between the NL zones, one would expect similar prices or that one zone would experience higher prices and the other would experience lower prices. This observation suggests that the available transmission capacity calculated with FBMC may be lower than in the scenarios and, thus, that the decreasing costs before and after the split are more related to the higher available transmission capacity. Again, the only price that went up after the split is in scenario 1 in the south of the Netherlands. In this scenario, the available transmission capacities are very low, at only 10%.

In the model methodology, it was discovered from ENTSOE (n.d.-b) that the available transmission capacity between the Netherlands and Germany, as well as the Netherlands and Belgium, was slightly below 20%. This may be the explanation for these notable results. Transmission capacity going to Belgium and Germany should maybe be estimated lower.

Next, it can be observed that for all scenarios except scenarios 7 and 9, the average prices of the North zone are lower than those of the South zones. For scenarios 4 and 6, the prices are only slightly different. The remainder of the scenarios have significant differences. To look more into these differences, a box plot is created for the price difference between the north and the south zones for every scenario. This is displayed in Figure 4.7. The full price curves of the total examined time period are attached in Appendix **??**. The largest price differences are observed in September and October. This could be the result of solar production. Additionally, scenario 1 also experiences price differences throughout the whole period.

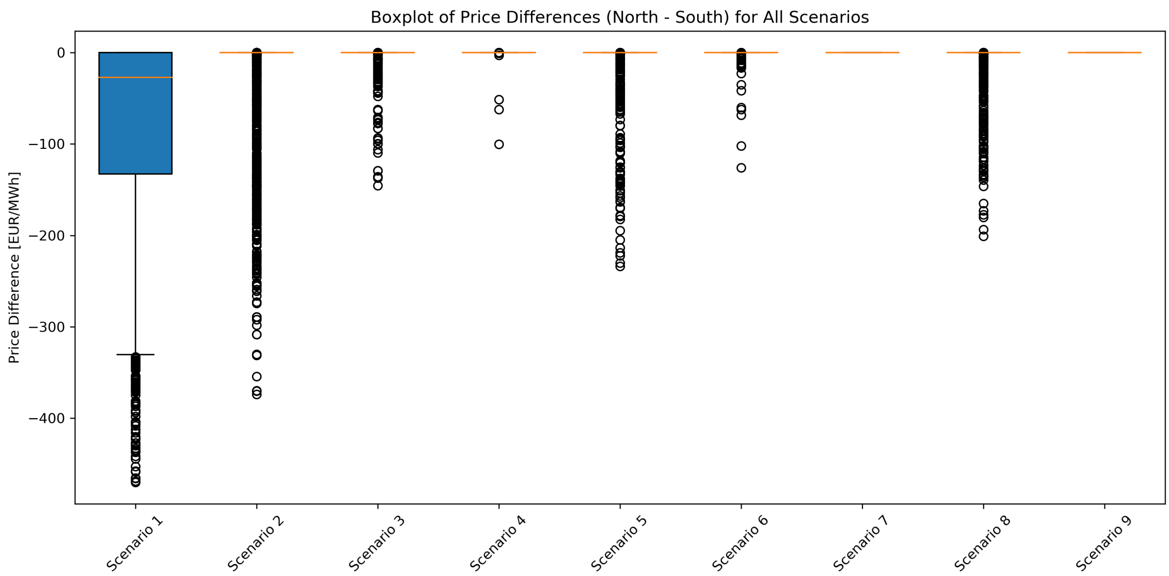

Figure 4.7: Price differences north and south for all scenarios

In scenarios 5, 6, and 7, as well as scenarios 8 and 9, only the commercial transmission capacity between the two NL zones is changed, keeping the other cross-border capacity the same. From these scenarios, it can be seen that the prices of the NL zones converge above a capacity of 50%. At 40%, they only slightly differ.

Next, the effect of the split with the different scenarios on neighboring countries is evaluated. The average prices for every scenario of Belgium and Germany are compared. They are also compared to the prices of NL North and NL South. This is displayed in Table 4.5. In this table, it can be observed that after the split, the prices went down in both Germany and Belgium. The prices of Germany and Belgium are impacted in all scenarios. In scenarios 5, 6 and 7, the transmission capacity between the NL zones is slightly increased. The same is true for scenarios 8 and 9. It seems that there is little effect on German and Belgian prices. They are affected more by changes in their own cross-border capacity with the Netherlands.

To illustrate what a price difference between the North and South zones in the Netherlands would mean, a small case calculation is done. A calculation is done to see what type of impact this split can have on large electricity consumers. This calculation is inspired by the article by Financieel Dagblad (2024). This experiment uses a large zinc factory located in Budel as an example. The factory has a capacity of 150 MW. The factory converts zinc sulfate solution to pure zinc by using electrolysis. It is assumed that the factory runs every hour at this capacity. According to the factory owner, the factory has to run every hour of the year to make enough profit. The evaluation period for all experiments is September-October. The electricity costs for those four months for this factory are calculated for every scenario in the North zone and the South zone, based on the hourly price found in the experiments. The outcome is displayed in Table 4.5. Significant differences exist in scenario 1, 2, 5 and 8. Building a large factory in another zone could make a difference of millions of euros. All other scenarios show little or no differences. These numbers are, of course, large amounts of money for this factory. Thus, locating a large-scale factory in the north or south NL zone would be relevant. However, the scenarios in which these huge differences are found are those with conservative capacity estimations.

Finally, the net positions of the new NL zones are evaluated. A box plot of the net positions for all scenarios is shown in Figure ... All scenarios are compared to the no-split scenario. The no-split scenario shows that NL is mostly an importing zone. It should be noted that when comparing this with validation data in the first experiment, it was observed that ENTSOE data shows NL as an exporting zone. Aside from this, it is clear that the northern zones are almost exclusively exporting electricity, and the southern zones are mainly importing electricity. This is because the northern zone produces more electricity than it consumes. From Appendix **??**, it can also be observed that in a few scenarios, the northern zones reach prices of 0€/MWh. This means that the demand is fully captured by renewable production. The northern zone has a higher generation capacity compared to the southern zone. The southern zone relies on electricity imported from the north.

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The findings of this scenario experiment are summed up in the following points:

1. When comparing the prices before and after the split, the prices go down for all scenarios after the split, except for scenario 1. In Germany and Belgium, all prices go down after the split. These changes seem to be more connected to the commercial transmission capacity going from the Netherlands to Germany and Belgium than between the split of the NL zones.

2. The largest price differences between the North and South NL zones are observed in September and October, mostly in scenarios 1, 2, 3, 5 and 8. These scenarios have 20%, 30%, and 30% transmission capacity between the NL zones. These prices can have a high impact on large electricity consumers. The prices converge above 50% transmission capacity between the North and South NL zones.

3. The north NL zone is an exporting zone for all scenarios, while the south NL zone is an importing zone for all scenarios. The northern zone reaches a period with prices of 0€/MWh, fully running on renewables. The northern zone produces more electricity than it consumes.

Scenario	DE [€/MWh]	BE [€/MWh]
No split	221.3	234.3
1	212.8	220.4
2	215.2	219.2
3	216.0	217.5
4	215.9	216.7
5	215.0	217.9
6	215.1	217.8
7	215.1	217.9
8	214.5	217.0
9	214.7	216.7

Table 4.4: Effect on average day-ahead prices for Germany and Belgium

Scenario	North [M€]	South [M€]
No split	104.1	104.1
1	77.6	110.4
2	91.5	99.3
3	95.2	95.7
4	95.0	95.1
5	96.4	98.1
6	98.1	98.2
7	98.2	98.2
8	94.9	96.3
9	96.1	96.1

Table 4.5: Cost comparison large electricity user

5 Discussion

In this section, the split will be analyzed further based on the model findings and on other research sources. The layout of the electricity system in the Netherlands is analyzed first. Next to this, a perspective on other developments in the electricity market is related to the Dutch bidding zone split. Then, the position of energy companies and consumers is discussed. Lastly, the findings of the thesis are positioned in current academic literature, and the limitations of the thesis research are discussed. This discussion will combine the numerical outcomes of the modeling with knowledge of the electricity market to encover the final answer to the research questions.

5.1. Layout of the Netherlands

A few interesting elements concerning the layout of the electricity system are observed. These are the locations of the interconnecters, the distribution of the load and generation and internal transmission lines.

The Netherlands currently consists of one bidding zone. It is connected to its neighboring countries through interconnectors. These interconnectors connect the Netherlands with Germany, Great Britain, Belgium, Norway and Denmark. There is one interconnector going to Great Britain, one to Norway, one to Denmark, and multiple to Belgium as well as Germany (JAO, 2023). When performing a split, the interconnections will no longer be attached to one NL zone, but to the North or the South zone. Figure 5.1 shows that the interconnectors to Great Britain and Belgium will belong to the South zone, while the interconnectors to Denmark and Norway will belong to the North zone. Interconnectors to Germany are present in both zones. (Concerning Figure 5.1, the transmission lines are illustrated as going to the main capital of the neighboring countries, but in reality, they go to connected substations.) This research found that the DC lines going to Great Britain, Norway, and Denmark operate at a high utilization factor. The northern part of the Netherlands especially benefits from this. It is connected to Norway and Denmark. Norway produces low-priced electricity through hydropower. Furthermore, the north of Germany is known for its high renewable production. This could become interesting when the potential German split between the north and the south is also realized.

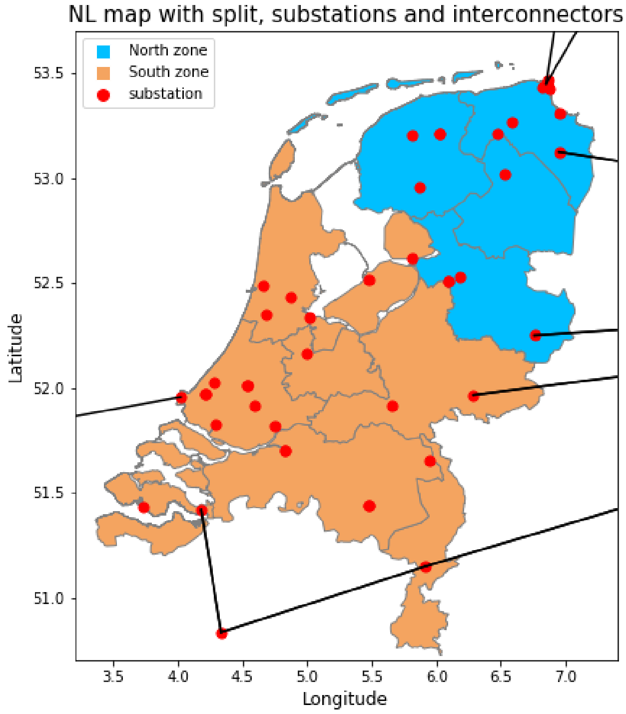

Figure 5.1: Map of the Netherlands with a split

The load is split into two zones as well. In the modeling done in this thesis, the nodal demand was split based on NUTS3 population size and GDP. By using this assumption, the northern zone accounts for 13% of the load and the southern zone accounts for 87% of the load. This makes sense as the population size of the north zone is not as densely populated and contains less industry. This nodal analysis also discovered that the northern zone is primarily exporting and the southern zone is primarily importing electricity. Due to its low demand and relatively high installed capacity, the northern zone seems to cover its own demand. It could even run on renewables in periods with a lot of sun.

The final important element in the layout of the Netherlands is internal transmission. After performing a split, former internal lines will connect the new zones in the Netherlands. The lines connecting the new zones are displayed in Table 5.1. This data is taken from JAO (2023). The line, thermal limit, and the substations it connects are provided. There are 8 lines connecting the two different zones. When the split is executed, these lines will no longer be viewed as internal zone lines but as interconnecting lines between the NL zones. Splitting the bidding zone will change internal congestion patterns. Tennet (2024) released a report concerning the transmission capacity made available for cross-zonal trade in 2023. In this report, the current state of the CNEs is evaluated. These CNEs limit cross-zonal trade. The three worst-performing CNEs were located near Zeeland and South Holland. Tennet (2024) explains that these were very minimally constraining day-ahead market coupling. They have also investigated loop flows going through the Netherlands. The CNE that stands out the most is located at the border of Groningen and Germany and is called Meeden-Diele. It experiences many loop flows originating from wind production in the north of Germany. Two paths are identified by Tennet (2024), where the loop flows usually lead. These are highlighted in Figure 5.2 and 5.3. The paths go through the Netherlands and back to Germany, or go to Belgium and then to Germany. The red lines are thus the affected elements. These are congestion patterns going from the north to the south of the Netherlands.

Line ID	From Substation	To Substation	F_l summer [MW]	F_l winter [MW]
2192	Doetinchem (South)	Hengelo (North)	1732.05	2147.74
2193	Doetinchem (South)	Hengelo (North)	1732.05	2147.74
2201	Ens (South)	Zwolle (North)	1732.05	2147.74
2202	ENS (South)	Zwolle (North)	1732.05	2147.74
2239	Hessenweg (North)	Ens (South)	952.63	952.63
2240	Hessenweg (North)	Ens (South)	952.63	952.63
2249	Oudehaske (North)	Ens (South)	952.63	952.63
2250	Oudehaske (North)	Ens (South)	952.63	1047.89

Table 5.1: Lines connecting North and South

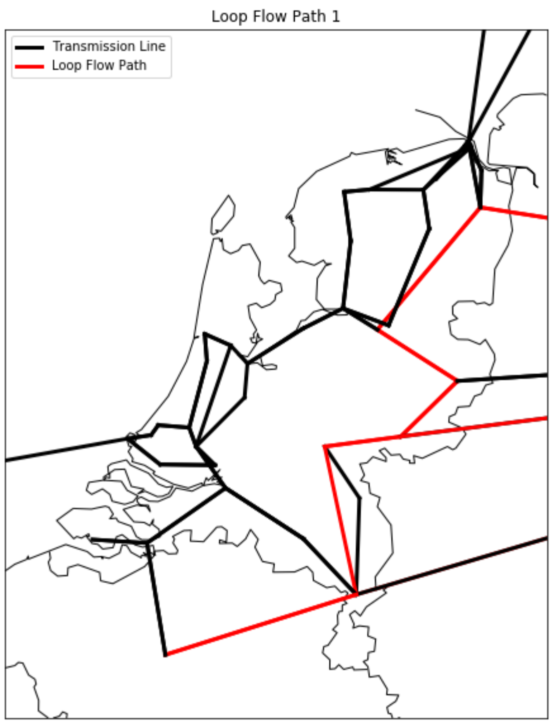

Figure 5.2: Loop flow path 1 in NL

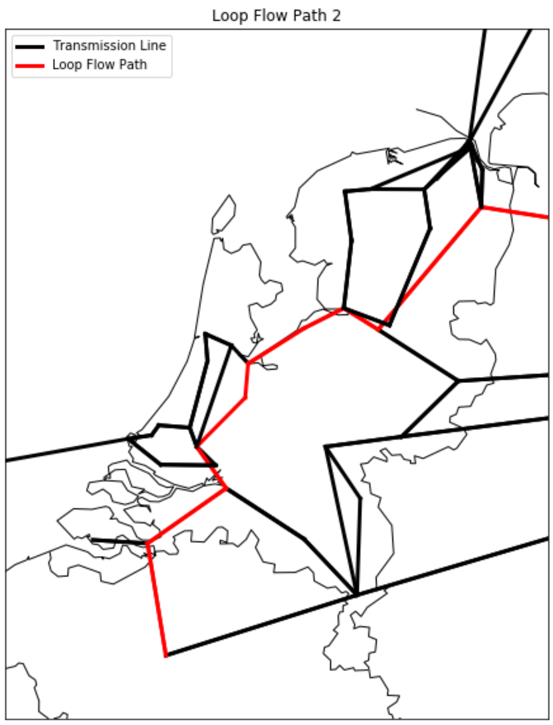

Figure 5.3: Loop flow path 2 in NL

If these loop flows keep coming from Germany, they will also limit transmission capacity between the new NL zones. Having transmission capacity allocated between the new NL zones will not change the unplanned flows coming from Germany. The unplanned flows will limit the transmission capacity that can be offered to the market. It was uncovered that only around 20-30% of transmission capacity between the Netherlands and Germany (and Belgium) is used. This observation, combined with the known unplanned flows going from the north to the south of the Netherlands, makes it unlikely that the commercially available transmission capacity of 70%, the EU goal, will be reached. From the scenario analysis performed in this thesis, it was concluded that any availability above 50% of the thermal limit of these lines would cause the prices in the northern and southern zones to converge. If the available transmission capacity is lower, the prices will differ. In the scenario analysis research, scenarios 8 and 9 resemble the available transmission capacities to the neighboring zones the best. Assuming that the loop flows from Germany will indeed have a significant impact on commercial transmission capacity between the NL zones, scenario 8, which has an available transmission capacity of 30%, is the most realistic. This will lead to price differences between the north and the south zones. In the factory experiment, it was calculated that this would cause a price difference of 1.4M€ (in 4 months), for this specific large electricity user, depending on where its factory is located. This lacking available transmission capacity may be improved quickly, the EU zones have created plans to bring these capacities up. The capacity may be improved by the reduction of loop flows coming from Germany. Additionally, when it is decided to split the Dutch bidding zone, Tennet may choose to expand capacity between the new NL bidding zones first.

The arguments made in this section show that the northern NL zone has some benefits compared to the southern zone. It is connected to Norway and the north of Germany, known for their low-priced electricity. Furthermore, the northern NL zone has a surplus of produced electricity compared to its small demand. These advantages go away if enough transmission capacity is available between the North and South zones, because prices will converge. The congestion patterns influence this commercial transmission capacity in the Netherlands and depend on a possible German split.

5.2. Other developments in the electricity system

The reconfiguration of bidding zones is not the only development in the electricity system. This section will provide a perspective of other current developments that influence the advantages and disadvantages of a Dutch bidding zone split.

Firstly, the Bidding Zone Review also investigates a possible split in Germany among other countries. The previous section highlighted how loop flows originating in Germany cause congestion in the Netherlands and how they influence the new cross-border in the Netherlands. Congestion caused by Germany in its neighboring zones is mainly related to cheap renewable electricity sold to users in the south, while internal transmission capacity is lacking. If a bidding zone split in Germany is executed between the north and the south, this will mean that transactions will align better with the actual grid. Transmission capacity on the cross-border of the north and the south of Germany will have to be allocated. So electricity from the north of Germany will not be as conveniently sold as before when it was based on unlimited free allocation. This may lead to fewer transactions between the north and the south of Germany (aligning with limited transmission capacity between the two zones), reducing loop flows targeting the Netherlands. The reduction of loop flows will fix a couple of problems. First, it will enlarge the available transmission capacity offered to the market between the NL zones. This will lead to more price convergence between the zones. Secondly, it will enlarge the commercial transmission capacity on the cross-border of Germany and the Netherlands, as well as on the cross-border of the Netherlands and Belgium. As was stated in the congestion report of Tennet (2024), loop flows from Germany also flow from the Netherlands to Belgium and then to Germany. This means that the Netherlands will have higher access to renewable electricity from the north of Germany, especially the northern NL zone. The Netherlands will most likely benefit from a German bidding zone split. A Dutch bidding zone split without a German bidding zone split may only create more difficulties in the Netherlands. Prices will differ inside the country and internal congestion may only be resolved minimally.

Another change in the electricity system is the expansion of offshore wind capacity. The modeling that was done in this thesis focused on the year 2022. In 2022, offshore wind capacity was less developed than it is today. The largest operating offshore farms are Gemini (600 MW), located near the northern NL zone, Windpark Fryslân (380 MW) in the northern NL zone and Borssele (1500 MW) located near Zeeland, which is in the southern NL zone. Then a few smaller wind farms (100 MW) are located in the south. At the moment of writing this thesis, in 2024, around 4.7 GW of offshore wind capacity is operating in the North Sea (Rijksdienst voor Ondernemend Nederland, 2021). In the following years, this capacity will expand even further. The Dutch government plans to reach an offshore wind capacity of 21.5 GW. Most of these offshore parks will be realized near the southern NL zone, with only 2.7 MW near the northern zone (Rijksdienst voor Ondernemend Nederland, 2021). In the modeling part of this thesis, it was discovered that the northern NL zone was exporting a lot of electricity to the South, with the northern generation exceeding its own demand. The south of the Netherlands, which hosts most of the demand, depended on importing electricity from other zones. Furthermore, the North had a relatively high renewable supply compared to its demand. This resulted in price differences between the North and the South. Expanding the offshore capacity, mainly in the southern zone, may change these dynamics between the North and the South. Nevertheless, this growing offshore capacity will also cause additional pressure on the electricity grid. This could lead to new congestion patterns. The new offshore parks seem to be located near North Holland and South Holland, where most of the demand is located. This is important, but additional capacity is probably necessary to prevent curtailment.

The Netherlands is not the only country that is expanding its offshore capacity. The UK, Norway, Denmark and Germany also have plans to expand on the North Sea. This brings us to another development: Offshore bidding zones. Currently, offshore wind farms are connected to their home market. Offshore wind farms belong to the bidding zone of their respective country. This may lead to an inefficient market. Their home market determines the electricity price of the offshore wind output. Meanwhile, with an offshore bidding zone, a couple of wind farms are grouped in hubs and form a bidding zone. In this new situation, the offshore bidding zones compete for interconnection capacity with onshore market players (ENTSOE, 2020). The price of the offshore bidding zone will generally be set by the bidding zone to which there is no congestion. An offshore bidding zone better reflects the physical grid and its obstacles. The offshore bidding zones integrate offshore renewable electricity better into the grid. It is hard to say how offshore bidding zones will affect the Netherlands without knowing their exact wind capacity and the location of the new cross-borders where capacity allocation will be needed. More research is needed into these new configurations.

Another important development is the expansion of the grid. Tennet has plans to expand the grid in the Netherlands and Germany, especially at the highly congested lines. This expansion is not an easy fix and will take several years to construct. The scenario analysis found that over 50% commercial transmission capacity is needed for price convergence in the Netherlands. Next to reducing loop flows, this capacity can also be improved with grid expansion. The grid should be able to handle decentral electricity generation. Together with the UK, Tennet is currently working on LionLink, which will connect the Dutch and UK grid via a Dutch offshore wind farm. This will help integrate offshore wind farms into the electricity system (ENTSOE, 2020).

Lastly, further electrification of industries, vehicles, and other appliances and systems is being executed. While solutions are developed for the increasing pressure on the grid, the demand for electricity keeps growing, especially with climate goal policies encouraging society to use less conventional energy sources and switch most energy usage to electricity. According to Planbureau voor de Leefomgeving (2022), electricity demand will grow from 391 PJ in 2021 to 395 PJ (+1% compared to 2021) in 2025 and 428 PJ (+9.5% compared to 2021) in 2030. This growing demand should be incorporated into the solutions, as it will create more pressure on the grid.

In summary, next to the bidding zone split, there are multiple developments in the electricity system. These developments are interrelated with each other, and all bring their uncertainties. Developments like the expansion of offshore capacity and the growing demand will threaten the functioning of the electricity grid. But on the other hand, there are grid expansion projects, the possible split of Germany, and the possible addition of offshore bidding zones. From the scenario analysis and the further discussion in this chapter, it can be learned that splitting the Dutch bidding zone is not a stand-alone event and will depend on changes in Germany.

5.3. Position of energy companies and consumers

Energy companies are responsible for supplying electricity to end-users. These end-users pay them for their electricity. Energy companies supply this electricity by having their own electricity production and/or by buying electricity from other electricity suppliers. This supply of electricity is collected in their portfolio. Portfolios can be optimized and changed. Energy companies want to meet the electricity demand of their customers while also making a profit and minimizing risks. This is why their portfolio is essential and needs to be diverse. A possible bidding zone split creates unwanted risks for energy companies. It may lead them to make different future investment decisions or review their current contracts.

First of all, the split in the Netherlands can create a price difference between the northern and southern bidding zones. This can create a difference in the prices that they offer to consumers. In Italy, this price is leveled over all different zones to give a uniform price to all consumers. In this way, people are not disadvantaged based on their geographical location. The Dutch government could adopt a similar strategy. This would, however, demotivate incentives for efficiency on the consumer side. Large consumers wouldn't face any differences in where their demand is located. If the prices remain different without government interference, this could relocate energy-intensive industries (if possible) to the northern zone. This could be an important move with further development of wind farm projects in the North Sea, both in the Netherlands and Germany.

For power plant owners, the price difference can impact the price they receive for the electricity they offer. In the higher-priced zone, the generators can obtain a larger revenue. There will be a strategic advantage and, thus, an incentive to place new power plants in the area where the highest price will be. Through the analysis of the layout of the Netherlands and the split configuration announced by ACER, there is an indication that if there is a price difference, the southern zone will experience higher prices. The southern zone has a higher demand and relatively less renewable capacity. Thus, it can be advantageous for energy companies to produce electricity in the south. However, the prices converge if the transmission capacity between the northern and the southern zones is sufficient. Energy companies can cover this potential risk by going through their portfolio and assessing where their assets are located. It is wise to ensure sufficient power plants or contracts to deal with exchanges in both zones separately. It can also influence their investment decisions. From this analysis, investing in new projects in the southern zone seems more logical, as demand is higher and supply is more scarce. This could be done by investing in new solar and wind projects or battery systems. Batteries could be charged during low-price hours, whereas electricity can be sold at high-price hours.

Another topic is the changes in forward contracts. These are long-term contracts between energy producers and buyers. Next to maybe owning power plants, energy companies buy their electricity from other parties. Forward contracts give assurance to producers and buyers. However, when the market zone is split, forward contracts must be renegotiated as they were based on one common bidding zone. Regarding the DE-AT split, contracts were negotiated to the new separate prices of Germany and Austria, with a weighted ratio of 9:1, according to market sizes. Government intervention may be needed for fair renegotiation. When forming new agreements, including a clause that entails bidding zone split implications may be wise.

Lastly, the split could impact energy companies due to the creation of smaller bidding zones. Smaller bidding zones will decrease the amount of competitors that a generator has in its bidding zone. This can potentially increase companies' market power. Increased power enables them to have a more considerable influence on the prices. Again, this is highly dependent on the inter-zonal transmission capacity. When having a large transmission capacity between different zones, the market power can be mitigated by competition from neighboring zones. From this analysis, it can be observed that the North zone may be at risk of market power. As was evaluated in the DE-AT split, where the market of Germany had a ratio of 9:1 compared to Austria in size, a reduction of market liquidity arose. This was only found in long-term contracts. These may be solved by managing the forward contracts differently and do not have to be affected by the size of the bidding zone.

In the modeling of this thesis, scenario 8, which has a commercial transmission capacity of 90% with DC-connected zones, 20% with AC-connected zones, and 30% in between NL zones, was created as scenario most in line with reality. In this scenario, the results showed differences in price between the north and the south of the Netherlands. As the capacity going to Belgium and Germany may be even lower than this scenario captures, the difference may even be higher than was predicted in this scenario. Based on this scenario, energy companies should prepare for the effects of the bidding zone split. A price difference will likely exist between the north and the south of the Netherlands. This price difference will, however, remain inter-related to developments in Germany. A German split may reduce loop flows in the Netherlands, enlarging the available commercial transmission capacity between the north and the south. This will reduce this price difference. When doing a German split, the price in the south may still be higher, especially because the low-priced northern part of Germany is closer to the north of the Netherlands. Next, long-term contracts should be updated with a way to handle the bidding zone split. Existing contracts should be renegotiated, and new contracts should have an extra clause that incorporates the effects of these two bidding zones. In this discussion, the other developments that impact the electricity system and, thus, energy companies are shortly explained. These should also be included in company decisions.

5.4. Academic reflections

This research will now be compared to other academic literature. The literature review found no research into the Dutch bidding zone split, but some research has been done into the bidding zone split in Germany. Aurora Energy Research (2023) researched the impact of the German bidding zone split on market prices. A bidding zone split roughly separating the north and the south of Germany is researched. They find an oversupply of 57% of generation to demand in the north of Germany by 2060 and an undersupply of 37% in the south of Germany in the same year. They also predict a price difference of 5€/MWh in 2030 and 9€/MWh in 2045, with the north having the lower price. This gap could be even higher if grid expansion is delayed. They also find that both zones have the same frequency of high-priced hours, but the north has more low-priced hours. They warn of a reduced profit for wind farms, which can jeopardize wind projects.

These results show a similarity between a split in the Netherlands and a split in Germany. In the Netherlands, the north also has an oversupply of generation to demand with a lower electricity price, while the south has an undersupply and a higher price. Aurora Energy Research (2023) does not mention any findings into the reduction of congestion. Furthermore, they warn of reduced market liquidity but do not explain why they reached this conclusion. Reduction in market liquidity is often cited in articles but never thoroughly proven. In the DE-AT split, it was only found for long-term contracts. Florence School of Regulation (2022) discusses this fear of market liquidity reduction. They also argue that this market liquidity problems only play a role in long-term markets. Next to this, they explain that exercising market power in smaller bidding zones is more transparent and easier to mitigate. Lastly, they question whether the reconfiguration of bidding zones may soon be outdated. Generation and demand patterns may change too fast. Nodal pricing seems to be a better option, in their opinion.

Multiple academics have proposed switching to nodal pricing. In this research, the nodal analysis has resulted in the finding of two groups of nodal prices: one higher-priced group in the west of the Netherlands and a lower-priced group in the east of the Netherlands. These findings do not align with the proposed reconfiguration that ACER has shared. One could question if ACER's clustering is the best method to create new zones and if this Dutch bidding zone split has enough advantages. This research also showed two particular nodes in the south of the Netherlands with a particularly high load compared to all other nodes. These differences are not captured in a large southern zone. Also, wind capacity expansion on the North Sea will significantly affect the electricity system of the Netherlands. All these elements will be better represented in nodal pricing, which has the most accurate price signaling and remains up-to-date with all developments.

5.5. Limitations of the model

The modeling in this thesis has some underlying assumptions that may limit or impact the model's outputs. The model has been validated with historical data and showed a significant gap between the backcasted day-ahead prices and the values published by ENTSOE. This was also the case for the net positions of the Netherlands and its neighboring countries. These gaps were reduced by better representing available transmission capacity with FBMC and NTC data. However, there were still price discrepancies. The Dutch net position also has a significant discrepancy. There are a few possible explanations for this gap. The gap may be explained by missing bidding zones, which influence the system. To provide a profound conclusion on these effects, the missing countries of the CORE region should be added to the model to analyze the full impact. The model considers a certain area of interest confined to the regions in Figure 3.2. There is no import or export from countries outside this region. However, in reality, the surrounding countries do have an impact on the evaluated countries. As the focus of this thesis is the Netherlands, the countries that impact the Netherlands must be modeled correctly. Interesting outliers are Poland, the Czech Republic and Austria. These countries are on the border of the area of interest, so they are missing their linking countries.

The missing import and export were evaluated with ENTSOE (n.d.-b) by looking at the commercial exchanges. In Table 5.2, the realized import/export capacity of missing connected bidding zones for the three countries is made explicit. The mean (μ) and median ($\mu_{1/2}$) of the period from September until December is provided. The mean is provided to give more information about the outlying values. However, as some outlying values exist, the median better represents the most common import/export. The percentage of the median of the import/export compared to the median of the total load (L) is stated in the last column for all Bidding Zones (BZ). Highlighted in red are the import and export percentages that are deemed significant (>1%). All significant cross-border trade is export. Including export capacities could significantly complicate the model. There always has to be a choice for a system boundary. Artificially adding missing export and import capacity without including the whole missing zones in the system may lead to more uncertainty. Furthermore, adding these new bidding zones to the system will again lead to new ones that are left out. So, it was decided to leave this unchanged. This limitation must still be considered when analyzing the predicted day-ahead prices. They may affect the bidding zones on the border of the zone of interest and bidding zones farther inside.

BZ 1	BZ 2	I/E	μ [MW]	$\mu_{1/2}$ [MW]	L BZ1 μ [MW]	L BZ1 $\mu_{1/2}$ [MW]	$\mu_{1/2}$(I/E)/L (BZ1) [%]
Austria	Hungary	Import	168	52	7007	6979	0.75
Austria	Hungary	Export	502	431	7007	6979	6.17
Austria	Slovenia	Import	95	9	7007	6979	0.13
Austria	Slovenia	Export	614	614	7007	6979	8.80
CZ	Slovakia	Import	31	3	7347	7368	0.04
CZ	Slovakia	Export	730	741	7347	7368	10.06
Poland	Lithuania	Import	137	53	19746	19868	0.27
Poland	Lithuania	Export	176	72	19746	19868	0.36
Poland	Slovakia	Import	29	0	19746	19868	0.00
Poland	Slovakia	Export	597	626	19746	19868	3.15
Poland	Ukraine	Import	54	0	19746	19868	0.00
Poland	Ukraine	Export	N/A	N/A	19746	19868	N/A

Table 5.2: Import/export on a cross-border compared to the total load of the respective bidding zone

Other identified reasons were outdated plant information and the renewable data from Volue, n.d., which is based on their modeling output and not on the actual output. These issues have not been solved in this thesis due to the lack of available and up-to-date data.

The main uncertain factor in the thesis is the new flow-based domain. In this research, a scenario analysis has been used. Its results are less realistic compared to using the exact projection method. In the scenario analysis, different available transmission capacities were used to explore the solution space of modeling the split in the Netherlands. These scenarios were constructed by varying the inter-zonal capacity between the new Dutch zones as well as between the Netherlands and other countries. By using this method, the commercially available capacity remains at the same percentage for all hours. In reality, this capacity changes depending on peak hours or peak days. In addition, it does not include the new uncertainties the bidding zone split will bring. Scenario 8 is closest to the expected situation, as it aligns with ACER sources. Theoretically, a bidding zone split will lead to a more efficient market and higher cross-zonal availability in the long run. This could mean a higher cross-zonal capacity between the Netherlands and Germany and between the Netherlands and Belgium. However, new congestion patterns may also arise, leading to a decline in transmission capacity. The transmission capacity between the new NL zones is especially essential to the research outcome. This capacity seems heavily affected by loop flows originating from Germany. It will, therefore, be very relevant to see the research into a German bidding zone split as well.

Another limitation of the model lies in its set-up. A backcast was created for September until December. As the model does not cover a full year, not all seasonal differences are covered. Furthermore, 2022 is only one single year. It may not be a representative year for forecasting because of temporary developments. In 2022, there were a lot of nuclear outages in France, which influenced the system. The interconnector between Norway and the Netherlands suffered from a lot of outages. Also, high gas prices because of the war in Russia are still prevalent. Then again, every year has its particular developments, and forecasting should be able to consider all these possible uncertainties. his time period was chosen due to the computational size and missing data. Once these issues are managed, a more extensive time period analysis will provide a more robust output. Including the full year of 2022 and 2023 will be a good upgrade.

Next, the model contains multiple assumptions that influence its outcomes. The power plants in the NL zone were assigned to the closest substation, and offshore wind parks were assigned similarly to the substation that connects the wind park with the electricity grid. The load was scaled to the nodes using NUTS3 population size and GDP, which may lead to inaccuracies. This assumption was made due to scarce data availability on the nodal load. However, GDP may not fully represent the industry's electricity demand.

Lastly, the Dutch bidding zone split was modeled while leaving the remainder of the modeled EU electricity system unchanged. However, ACER has published a bidding zone reconfiguration targeting France, Germany, Italy and Sweden. Bidding zone splits in France and Germany will also significantly impact the market conditions of the Dutch electricity market. Especially Germany, a significant source of unscheduled electricity flows in the EU, could create changes if a bidding zone split were to happen. Due to computational time and the need to maintain a workable size of the model, a split in Germany was not simulated in this research. Nevertheless, adding a split in Germany to the model would be interesting. Splitting Germany into a north and south zone could interact with the Netherlands' north and south bidding zones, possibly lowering prices in the northern NL zone even more.

5.6. Limitations of the software

In this thesis, modeling was done with Plexos software. Plexos was chosen as a modeling tool due to the author's involvement with Eneco. Eneco provided a reference model that could be used as a starting place. Due to unexpected difficulties in the modeling process, including the exact projection method to calculate the new flow-based domain of the Netherlands was impossible. To still provide a meaningful analysis of the split, this method was replaced by a nodal model of the Netherlands and a scenario analysis of possible transmission capacities. However, this did not give a full picture of the impacts as the author had intended. The author has found it infeasible to do this type of modeling in Plexos without using additional tools, as was discussed in the methodology. Perhaps using different tools would have provided the opportunity to implement the intended modeling strategy. Furthermore, as Plexos is a closed software, little information is available on its limitations and on problem-solving aside from the software's own documentation. A help desk is available for some questions but only goes into trouble-shooting in the program or supplying demos. This may be different when using open-source programming tools such as PyPSA, which has many users and online discussion platforms.

6 Conclusion

ACER has proposed a reconfiguration of the bidding zones of numerous European countries to mitigate grid congestion in the EU. For the Netherlands, ACER suggested a split roughly separating the 4 northern provinces, Groningen, Friesland, Drenthe, and Overijssel, from the south of the Netherlands, which contains the remaining provinces. The literature study identifies a knowledge gap in research on the effects of a bidding zone split in the Netherlands. Therefore, this thesis answers the following main research question: *How will splitting the electricity bidding zone in the Netherlands impact commercial cross-border exchanges and electricity prices in the Day-Ahead market in the Netherlands and its neighboring countries, and what risks does this split cause for energy companies?* This question is investigated using lessons from the recent bidding zone split between Germany-Luxembourg and Austria and by creating an economic dispatch model to do a nodal analysis of the Netherlands and evaluate possible scenarios of the Dutch bidding zone split. The obtained lessons from the literature review and the quantitative consequences of the market zone split are used to analyze the Dutch bidding zone split and its impact on market players.

The unplanned flows that produced additional congestion management costs in neighboring countries were the main reason for the split of the DE-AT zone. The Polish electricity grid, in particular, suffered severely from these additional costs. However, no significant improvement in unscheduled flows was found in Poland. A lot of resistance against the split came from Austrian market players due to fear of increased electricity prices and market liquidity reduction. After the split, Austrian electricity prices did indeed increase, and there are indicators of deterioration in Austria's market liquidity in the long-term electricity market. Germany did not experience these negative effects. Lastly, long-term contracts were renegotiated. The same consequences may apply to a split in the Netherlands, which has a similar market size ratio between North and South as Austria and Germany. Furthermore, the north of the Netherlands had a power surplus, as did Germany. Another important element is the fact that Germany is a significant source of loop flows affecting a large part of the electricity grid in the EU. Austria obtained evidence that points out internal congestion in the German electricity grid as the main instigator of unplanned flows in the CEE area.

During the design process of the economic dispatch model, a change in flow-based domains was found to be a large unknown variable. Exact Projection was posed as a solution to avoid this unknown variable but was later discarded due to implementation troubles. A more practical approach was taken by conducting a scenario analysis. Based on a reference model, a backcast simulating the months of September until December 2022 was created. Three models were created and evaluated. First, the reference model was improved to provide a basic starting scenario. Second, a nodal model of the Netherlands was created to evaluate local prices. This nodal analysis resulted in a distribution of two price groups: high-priced nodes in the west and low-priced nodes in the east of the Netherlands. This difference in nodal prices can be explained by three reasons: (1) the high load density in the west, (2) congestion patterns in the high-priced areas, and (3) the geographical positions of fossil power plants.

Third, a bidding zone split in the Netherlands was simulated by separating demand and generation into the proposed north and south zones. 9 scenarios were created and the percentage of the thermal limit made available for transmission was changed for every scenario. This scenario analysis evaluated the effects on prices and cross-zonal trade. Prices after the bidding zone split of the Netherlands were reduced in the Netherlands, Belgium, and Germany for all scenarios. It was observed that an available transmission capacity of 20% and 30% created a significant price difference between the two NL zones, with the northern zones experiencing lower prices, even going to 0€/MWh in the summer period. Above a 50% available transmission capacity, the electricity prices of the two Dutch zones converged. Scenario 8, which is the closest to the expected new situation after the split, shows an average price difference of 3.1€/MWh between the two zones.

In the in-depth analysis, the northern zone was found to represent 13% of the total NL load while the southern zone hosts 87%. The northern zone also generates a surplus of electricity, exporting it to the south. The northern zone has the advantage of being closer to the low-priced electricity from Norway and the north of Germany. The availability of commercial transmission capacity between the two new Dutch zones is key to the price behavior of both zones. The transmission capacity will be influenced by congestion patterns coming from loop flows in Germany. The possible price difference has an impact on energy companies and their portfolios. New power plants could benefit from being developed in the southern zone, where electricity prices are higher due to scarcity of supply and a higher electricity demand. Changes in long-term contracts can be mitigated based on the weighted ratio of market sizes, similar to the DE-AT approach.

Next to the possible split in Germany, other developments in the electricity sector will influence the advantages and disadvantages of the proposed bidding zone reconfiguration in the Netherlands. A significant addition of offshore wind capacity near the southern shore of the Netherlands will better match the large demand there, but it will also increase the pressure on the grid. The expansion of the grid is planned but may not be realized fast enough to capture the growth of generation and demand. In other research, it is found that a German split has some similarities to the NL split, with higher prices in the south. This split will interact with the results presented in this thesis. In the end, the new configurations of the Netherlands and Germany may not fully capture the zone's price differences. They may be unable to stay current with all developments in the energy sector. A change to nodal pricing may be a better solution.

Policy-makers, energy companies, and consumers are awaiting ACER's advice on the final bidding zone reconfiguration in the EU. This study has shown the impact that the Dutch bidding zone split has on electricity prices, cross-border exchanges, and energy companies.

6.1. Reflections

The research in this thesis consists of three parts: the literature review on the DE-AT split, the modeling part, and the effects of the split on market players. In the author's opinion, examining a similar bidding zone split provided insights into reoccurring problems. The DE-AT split showed similar reasons for reconfiguration as well as similar market player oppositions. However, it has proven difficult to precisely position the similarities of the two splits next to each other and include these in the analysis. Furthermore, a lot of time was spent implementing the Exact projection method in the modeling part. In hindsight, it would have been better to find out all the limitations of the modeling software before choosing to use it. After only a few weeks, this decision was made to keep as much time for the modeling as possible. Choosing another modeling tool may have given more significant results. Lastly, an analysis was done on the position of energy companies. In the author's opinion, this can be a study in itself. More research into market power effects, as well as a full analysis of existing assets and contracts, would be a meaningful addition to the work. However, these were left out due to the project's time management.

6.2. Recommendations

The main contributions of the model developed in this research are the nodal analysis and the scenario split analysis. Energy companies can use the model's output for insights in their forecasting. Also, using the same method, the model's set-up can be expanded to include a German and French bidding zone split. New scenarios can then be created to simulate bidding zone reconfigurations in the entire coupled European electricity system.

Based on the scenario analysis in this research, it was found that an available transmission capacity below 50% of the thermal limit will lead to price differences in the two NL zones. High price differences were found below 30%. To cover the risk of price differences between the two new NL zones, energy companies should consider rebalancing their portfolio. The locations of all assets and consumers should be analyzed. Current PPAs may need to be renegotiated to account for the new price dynamics after the split. Incorporating clauses into new contracts that consider these price differences should be included for a smooth transition. Lastly, when a price difference will present itself after a split, due to limited transmission capacity, the southern zone will experience higher prices. This is due to the relatively high demand and low supply. It would be strategic for energy companies to invest in new assets in the southern area. These could entail renewable energy production and battery storage projects. Energy companies should follow the decision of ACER and of the Dutch policy-makers closely.

In future research, it will be interesting to provide a better approximation of the split's effect on the Netherlands' new flow-based domain. In this thesis, including the exact projection method in the modeling was not successful due to the limitations of the used optimization software. Furthermore, the literature review noted that the expected reduction of unplanned flows in Poland due to a split between Austria and Germany was not resolved. Austrian market players blamed German internal net congestion for most of these problems. The split of the German bidding zone will also have implications for the electricity system of the Netherlands. This influence also needs to be studied, as it interacts with the new NL zones as well. Lastly, a congestion analysis of the Netherlands before and after the split should be performed. This could show policymakers and grid operators if the desired effects of splitting the bidding zone are achieved, whether congestion will improve, and whether these improvements are worth the troubles of the bidding zone split. Also, new congestion bottlenecks will need to be identified.

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A

Appendix

A.1. Histograms of Import and Export, calculated with the Forecasted day-ahead transfer capacities as Percentage of Max Capacity 2022

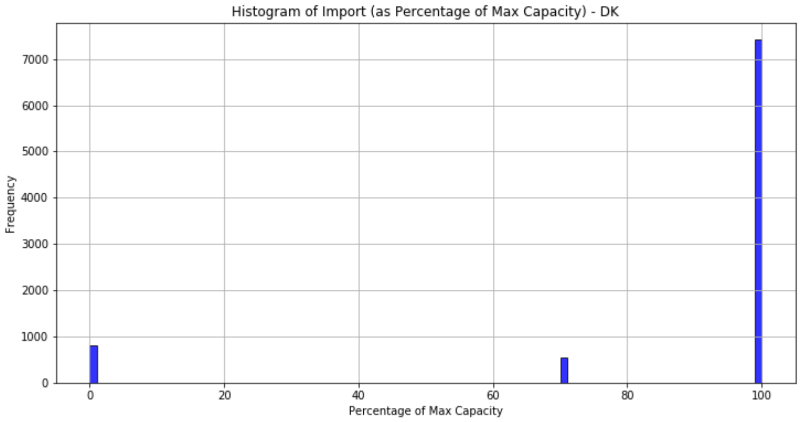

Figure A.1: Histogram of Import (as Percentage of Max Capacity) - DK

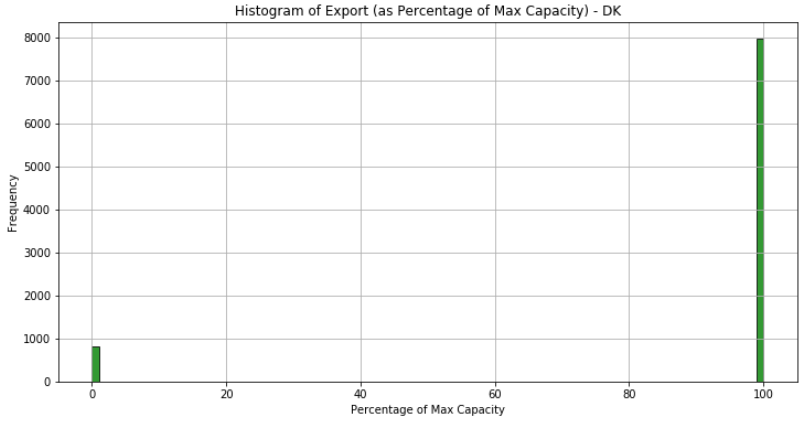

Figure A.2: Histogram of Export (as Percentage of Max Capacity) - DK

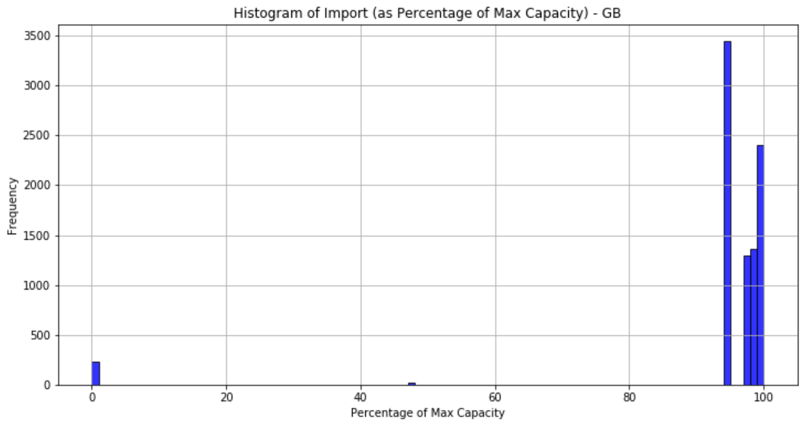

Figure A.3: Histogram of Import (as Percentage of Max Capacity) - GB

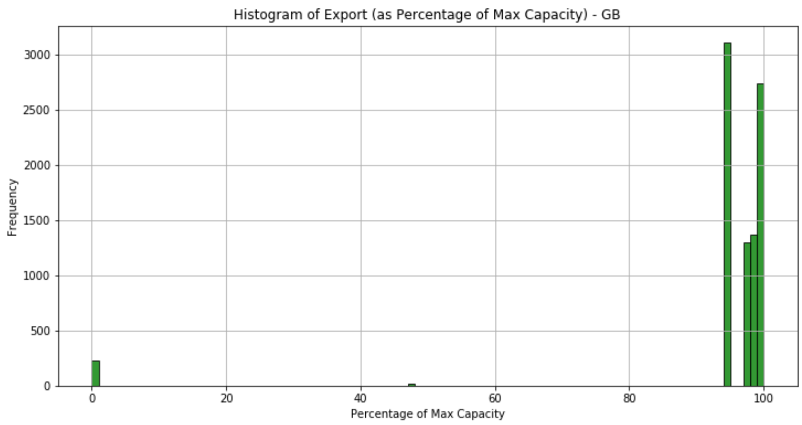

Figure A.4: Histogram of Export (as Percentage of Max Capacity) - GB

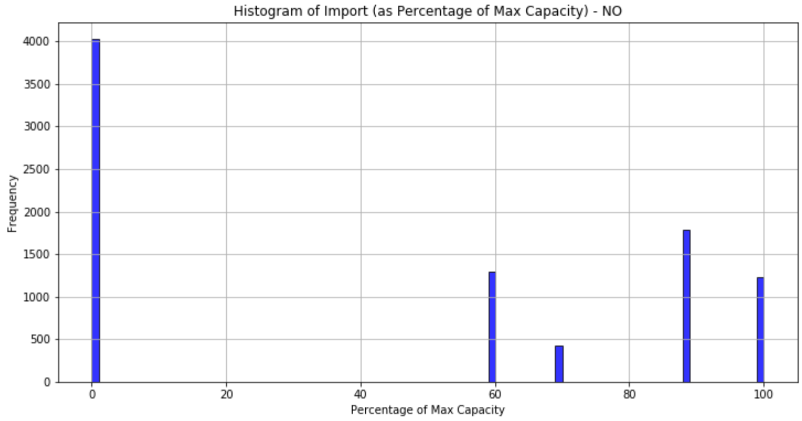

Figure A.5: Histogram of Import (as Percentage of Max Capacity) - NO

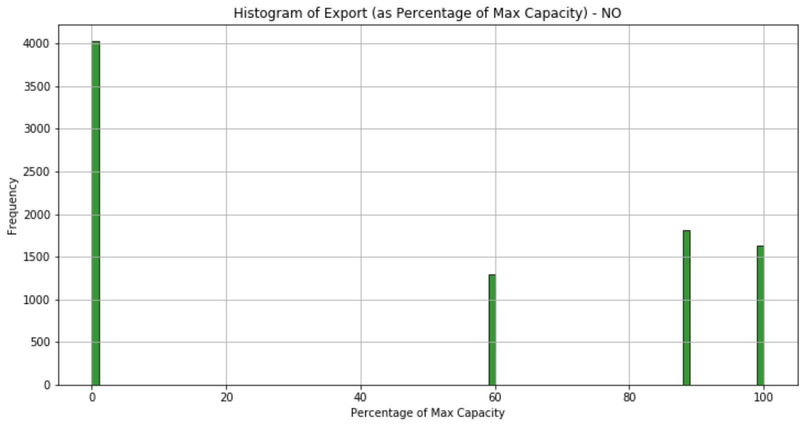

Figure A.6: Histogram of Export (as Percentage of Max Capacity) - NO

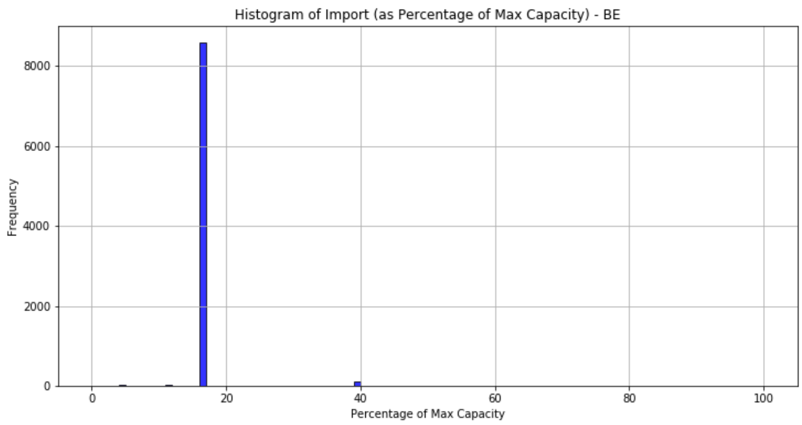

Figure A.7: Histogram of Import (as Percentage of Max Capacity) - BE

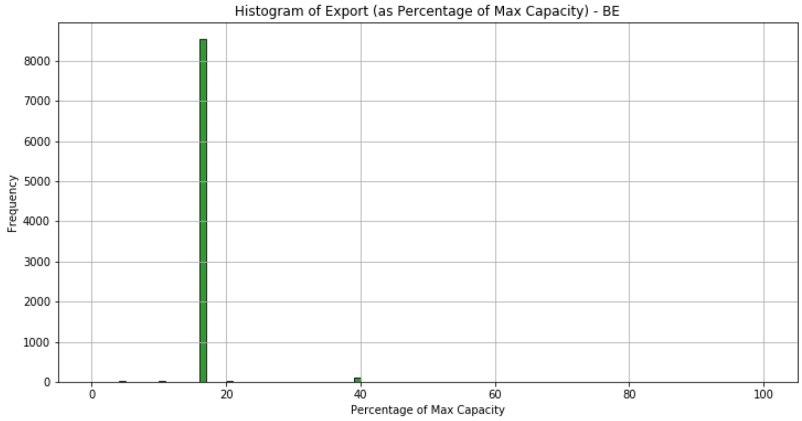

Figure A.8: Histogram of Export (as Percentage of Max Capacity) - BE

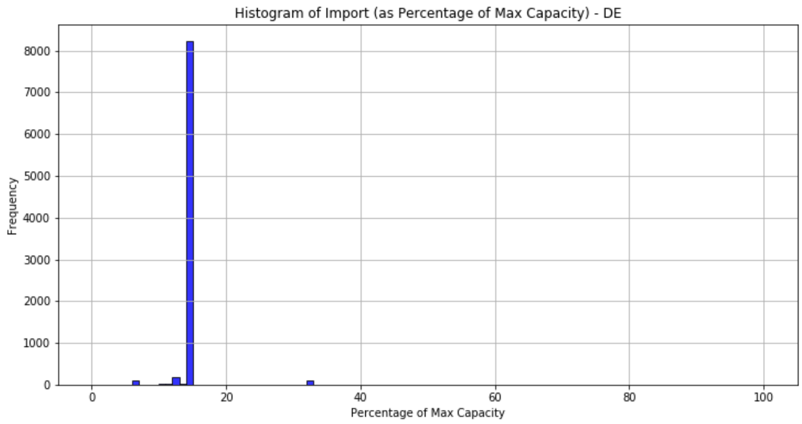

Figure A.9: Histogram of Import (as Percentage of Max Capacity) - DE

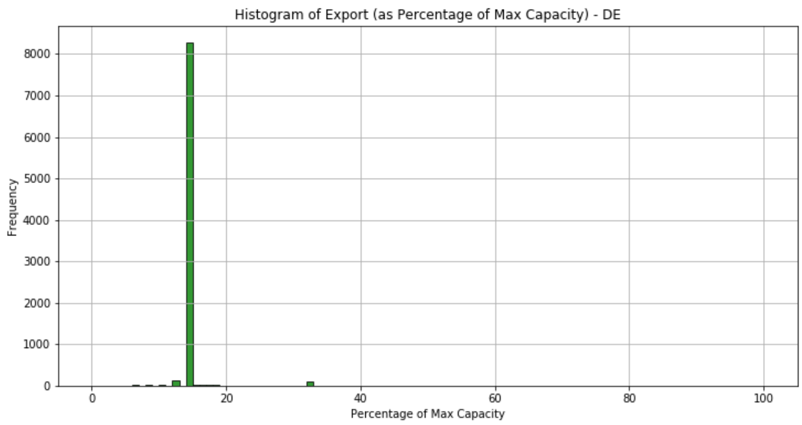

Figure A.10: Histogram of Export (as Percentage of Max Capacity) - DE

B

Appendix

Line	Method	Source	Notes
AT-to-ITN	NTC	ENTSOE	Day-ahead
CH-to-AT	NTC	ENTSOE	Day-ahead
CH-to-DE	NTC	ENTSOE	Day-ahead
CH-to-ITN	NTC	ENTSOE	Day-ahead
CZ-to-AT	FBMC	JAO	
CZ-to-DE	FBMC	JAO	
DE-to-AT	FBMC	JAO	
DE-to-BE	FBMC	JAO	
DE-to-NL	FBMC	JAO	
DE-to-NO2	NTC	ENTSOE	Week-ahead
DE-to-PL	FBMC	JAO	
DE-to-SE4	NTC	ENTSOE	Week-ahead
DK1-to-DE	NTC	ENTSOE	Day-ahead
DK1-to-DK2	NTC	ENTSOE	Week-ahead
DK1-to-NL	NTC	ENTSOE	Day-ahead
DK1-to-NO2	NTC	ENTSOE	Week-ahead
DK1-to-SE3	NTC	ENTSOE	Week-ahead
DK2-to-DE	NTC	ENTSOE	Day-ahead
DK2-to-SE4	NTC	ENTSOE	Week-ahead
FR-to-BE	FBMC	JAO	
FR-to-CH	NTC	ENTSOE	Day-ahead
FR-to-DE	FBMC	JAO	
FR-to-ES	NTC	ENTSOE	Day-ahead
FR-to-GB	NTC	ENTSOE	Day-ahead
FR-to-ITN	NTC	ENTSOE	Day-ahead
GB-to-BE	NTC	ENTSOE	Day-ahead
GB-to-NL	NTC	ENTSOE	Day-ahead
GB-to-NO2	NTC	ENTSOE	Week-ahead
ITCa-to-ITS	NTC	ENTSOE	Day-ahead
ITCa-to-ITSi	NTC	ENTSOE	Day-ahead
ITCS-to-ITCN	NTC	ENTSOE	Day-ahead
ITCS-to-ITN	NTC	ENTSOE	Day-ahead
ITCS-to-ITS	NTC	ENTSOE	Day-ahead
ITN-to-ITCN	NTC	ENTSOE	Day-ahead
ITSa-to-ITCS	NTC	ENTSOE	Day-ahead
NL-to-BE	FBMC	JAO	
NL-to-NO2	NTC	ENTSOE	Day-ahead
NO1-to-NO3	NTC	ENTSOE	Week-ahead
NO1-to-SE3	NTC	ENTSOE	Week-ahead
NO2-to-NO1	NTC	ENTSOE	Week-ahead
NO4-to-NO3	NTC	ENTSOE	Week-ahead
NO4-to-SE1	NTC	ENTSOE	Week-ahead
NO5-to-NO1	NTC	ENTSOE	Week-ahead
NO5-to-NO2	NTC	ENTSOE	Week-ahead
NO5-to-NO3	NTC	ENTSOE	Week-ahead
PL-to-CZ	FBMC	JAO	
PL-to-SE4	NTC	ENTSOE	Week-ahead
SE1-to-SE2	NTC	ENTSOE	Week-ahead
SE2-to-NO3	NTC	ENTSOE	Week-ahead
SE2-to-NO4	NTC	ENTSOE	Week-ahead
SE2-to-SE3	NTC	ENTSOE	Week-ahead
SE3-to-SE4	NTC	ENTSOE	Week-ahead

Table B.1: Overview of data input transmission lines.

C

Appendix

Node	Median Price [€/MWh]
1009	222.835
1059	223.02
1141	222.835
1156	198.77
1177	198.77
1242	198.145
1343	222.21
1363	222.21
1381	222.835
1414	223.02
1420	222.21
1450	223.02
1492	199.97
158	222.21
245	222.21
296	222.21
333	222.835
345	193
346	222.21
354	198.145
366	222.21
40	199.09

Node	Median Price [€/MWh]
524	198.77
532	222.835
58	199.09
590	222.835
605	199.09
63	198.77
676	222.21
678	199.09
70	198.77
733	198.145
737	222.835
76	222.83
795	222.835
809	199.09
818	198.545
841	222.835
859	222.835
864	223.02
903	222.835
906	199.09
97	198.145
984	198.77

Table C.1: Median of every nodal price