Study on the effects of alternative German and Dutch bidding zone configurations on socio-economic welfare and CO_2 emissions

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Contents

List of abbreviations

AC	Alternating Current
ACER	European Union Agency for the Cooperation of Energy Regulators
BZ	Bidding zone
BZR	Bidding zone review
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CHP	Combined heat and power cogeneration
DC	Direct current
DSO	Distribution system operator
ENTSO-E	European Network of Transmission System Operators for Electricity
EV	Electric vehicle
GHG	Greenhouse gas
GT	Gas turbine
GW	Gigawatt
HP	Heat pump
HVDC	High voltage direct current
Hydro PS	Hydro pumped storage
Hydro ROR	Hydro run of river
MW	Megawatt
MWh	Megawatt hour
NECP	National energy and climate plan
NEMO	Nominated electricity market operator
NR	Network reduction
O&M	Operation and maintenance
P2H	Power-to-heat
P2H2	Power-to-hydrogen
PV	Photovoltaics
RD	Redispatch
RES	Renewable energy sources
SEW	Socio-economic welfare
SMR	Steam methane reforming
TWh	Terawatt hour
TSO	Transmission system operator
V2G	Vehicle-to-grid

Executive Summary

The European electricity wholesale market is a zonal market that allows for trading across Europe given limited interconnection capacities between bidding zones. Countries generally consist of one or more bidding zones[1], which is defined as the area in which unlimited transport capacity for the market is assumed to be available ("copper-plate" assumption). As a consequence, there is only one wholesale electricity market price for each bidding zone (BZ). Different BZs show a different wholesale electricity price at times of congestion on one or more interconnectors between BZs. Introducing more BZs is a potential policy option to use the available technical interconnection capacity more efficiently; it allows electricity market prices to align better with physical reality and to provide better price signals to the market for both new investment (e.g. location choice) and operational decisions. This helps to achieve higher market efficiency and further decarbonization of the energy system, while ensuring system security.

The importance of BZs as a cornerstone of market-based electricity trading in Europe has been widely recognised by the European Commission, the European Parliament and the Council. EU Regulations 2015/1222 and 2019/943 set out detailed rules for the review of BZ configurations amongst others. As part of the most recent regular bidding zone review (BZR), in August 2022 ACER identified specific BZ configurations for examination by TSOs, including several configurations for Germany and the Netherlands (ACER, 2022). The effects of these BZ configurations are currently being examined by the TSOs supported by ENTSO-E. The target year of the BZR analysis is legally set at 2025. However, the outlook for the Northwest European electricity markets offers a varied picture with moderate to strong growth in electricity demand and supply beyond 2025. This raises questions for the Dutch Ministry of Climate Policy and Green Growth about the robustness of the alternative BZ configurations in the medium term. Questions include the impacts of these BZ configurations compared to the status quo configurations on socio-economic welfare (SEW)[2] and CO_2 emissions after 2025 as well as their robustness for a diverse set of scenarios concerning demand and supply developments towards 2035.

Therefore, this study aims to answer the following research question:

> *What are the effects of selected German and Dutch bidding zone configurations from ACER Decision 11-2022 on socio-economic welfare gains and CO_2 emissions of the CORE countries[3] in 2035 compared to the current bidding zones, under different scenarios for electricity demand and supply?*

[1] An exception is Germany and Luxemburg which form together one bidding zone.

[2] Welfare economics is the study of how the structure of markets and the allocation of economic goods and resources determine the overall well-being of society. Welfare economics seeks to evaluate the costs and benefits of changes to the economy and guide public policy toward increasing the total good of society. In the context of this study, socio-economic welfare is understood as the net benefits for society due to alternative BZ configurations i.e. the aggregation of the economic surpluses of electricity consumers, producers, and TSOs as transmission network owners ('congestion rents').

[3] The CORE countries are Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxemburg, the Netherlands, Poland, Romania, Slovakia and Slovenia. These are all countries in Continental Europe that from together the CORE capacity calculation region which is applied for European electricity market coupling.

The answer to this question serves as an input to the Dutch Ministry of Climate and Green Growth for the expected decision of the relevant EU Member States to amend or maintain the current BZ configurations given Article 14(8) of EU Regulation 2019/943.

For this assessment of BZ configurations, the following five step methodology is applied:

1. **Selection of BZ configurations**: Based upon the 14 alternative BZ configurations selected for the official BZR, three BZ configurations in the CORE region, for Germany and The Netherlands respectively, have been selected with the Dutch Ministry of Climate Policy and Green Growth for further research in this study;
   a) BZ split of Germany into 2 zones (BZR ID 2, hereafter called DE2)
   b) BZ split of Germany into 4 zones (BZR ID 13, hereafter called DE4)
   c) BZ split of the Netherlands into 2 zones (BZR ID 7, hereafter called NL2).

   Each individual BZ configuration is assessed against three 2035 scenarios to test its robustness against different possible supply and demand developments in the medium term. The analysis of effects of combinations of BZ configurations was outside the scope of this study;

2. **Scenario framework**: to cover the wide range of possible supply and demand developments towards 2035, existing scenarios for Germany (NEP23), the Netherlands (IP2024), and for France and other EU-27+ countries (ENTSO-E TYNDP) have been reviewed and combined in three scenarios for multiple countries. Each new BZ configuration requires that supply and demand of the country involved is distributed across the BZs within the country;

3. **Network reduction**: the Network Reduction (NR) method is applied to obtain simplified, equivalent electricity networks with a lower computational burden, resulting in transmission capacities and line susceptances for the different BZ configurations;

4. **Electricity market model runs with COMPETES-TNO** ('optimization model') to quantify amongst others the SEW and CO_2 emission effects of each scenario (step 2) and BZ configuration (step 1), taking into account network parameters (step 3);

5. **Analysis of incremental SEW and CO_2 emission effects**: incremental or relative effects are obtained by comparing model results (from step 4) for alternative BZ configurations one-by-one against model results for current country-based configurations corrected for higher dispatch costs due to relieving of some network constraints. In this context, SEW is understood as the net benefits for society due to alternative BZ configurations i.e. the aggregation of the economic surpluses of electricity consumers, producers, and TSOs as transmission network owners ('congestion rents'). The robustness of the different BZs is tested by assessing the extent to which net effects are significant and move in the same direction under different scenarios for generation and demand taken from step 1.

Net SEW gains and CO_2 emission reductions of alternative German and Dutch BZ configurations are significant

The study shows that the two alternative BZ configurations for Germany, with Germany divided in two (DE2) and four bidding zones (DE4) respectively, deliver significant incremental SEW gains for EU-27+ for each of the three scenarios in year 2035. The net SEW effects range from € 2.1 to 2.5 billion per year for the DE2 BZ configuration, and € 4.0-4.6

billion per year for the DE4 BZ configuration. For the NL2 BZ configuration, net SEW gains for EU-27+ amount to € 0.2-0.3 billion per year. The effects are thus an order of magnitude smaller compared to the alternative German BZ configurations, but still significant given that the accuracy of the SEW estimates is in the order of € 100 million. Generally, producers profits ('producer surplus') decrease, while consumers and TSOs benefit from increases of consumer surplus and congestion rents respectively. Overall, CO_2 emissions of the electricity sector for EU-27+ decrease by about 4 Mton and 6-7 Mton for the DE2 and DE4 BZ configuration respectively. For the NL2 BZ configuration, CO_2 emissions of the electricity sector for EU-27+ decrease by 0.5 Mton.

The net social welfare gains and CO_2 emission reductions result from more efficient use of the electricity network due to better integration of grid constraints in electricity markets with BZs. This means that part of the transactions that cause internal flows within Germany as well as loop flows through surrounding countries become subject to capacity limits during electricity trading. These restrictions within Germany relieve network capacity on the cross-zonal lines with neighbouring countries and result in an overall increase of available network capacity for the electricity market. Total available interconnection capacity increases by 5.6 GW and 6.7 GW in the DE2 and DE4 BZ configuration respectively, which is about 14-17% of the total available interconnection capacity before the BZ splits. The relative increases of available capacity for cross-zonal trade for these BZ configurations are quite similar to the increases reported by ACER (2022), supporting the validity of our results. The capacity increases concern mainly interconnections of Germany with neighbouring countries, especially with the Netherlands, Poland, Czech Republic, and Belgium, and to a lower extent with Austria and Slovakia. For the NL2 BZ configuration, total available interconnection capacity increases by 1.1 GW, which is about 3% of the total available interconnection capacity before the BZ split. This concerns mainly interconnections of the Netherlands with Germany, but also of Germany with Czech Republic, Austria, and Poland.

As a result, excesses of cheap electricity production can be more easily sold to other countries, while shortages of generation can be fulfilled with electricity from abroad against lower costs. Consequently, costs for the operation of the power system decrease compared to the base case that includes redispatch costs. Redispatch costs are defined as the costs of a measure that is activated by one or more TSOs by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion. Generation redispatch means switching off cheaper power plants that contribute to network congestion in certain locations, and switching on more expensive power plants on other locations that help to relieve network congestion. This constitutes a daily process organized by the TSOs. This less optimal dispatch of power plants to relieve congestion on some intra-zonal network constraints is already accounted for in the base case, which reflects the status quo situation and thus is not part of the incremental SEW effects mentioned before. Besides, the higher available cross-border network capacity in the DE2 and DE4 BZ configurations allow for the replacement of coal- and gas-fired generation with higher CO_2 emissions, both in Poland and to a lesser extent in Germany-South, by low carbon generation with lower CO_2 emissions in other countries. The NL2 BZ configuration also shows lower CO_2 emission reductions in Poland, but these are partially replaced by more CO_2 emissions in Czech Republic due to higher deployment of natural gas-fired power plants.

Net SEW gains and CO_2 emission reductions of alternative German and Dutch BZ configurations are largely robust

Given the significant net positive SEW and CO_2 emission effects in each scenario, the alternative German BZ configurations are robust for a wide range of future developments as summarized in the three decarbonisation scenarios for 2035. This includes futures which are characterised by larger roles for electricity and hydrogen in fulfilling demand, lower and higher shares of variable RES and nuclear generation, and varying deployment of flexible demand technologies such as power-to-heat, heat pumps, and electric vehicles. The NL2 BZ configuration is also robust for future developments, in the sense that all scenarios show a limited though significant increase of annual SEW. CO_2 emission reductions of this configuration are also of similar magnitude for different scenarios, but rather insignificant, and therefore considered somewhat robust.

The three decarbonisation scenarios for 2035 are likely to increase the SEW benefits of alternative BZ configurations in future electricity systems compared to the current electricity system for three reasons. First, given the combination of large variation in country-specific developments until target year 2035 and significant fuel and CO_2 prices, price differences between Western and Eastern European Member States are significant, increasing benefits of additional available interconnection capacity. Second, higher shares of variable renewable energy (VRE), which tend to be located further away from load centres, result in larger electricity flows over longer distances, increasing the need for electricity transport. Hence, additional available interconnection capacity from alternative BZ configurations is likely to show higher benefits in 2035 than today. Third, the increasing role of Power-to-Heat and Power-to-Hydrogen towards 2035, implies a larger deployment of conversion options once average electricity prices decrease due to more available interconnection capacity. This volume effect enlarges the incremental SEW effect substantially.

SEW effects should be balanced against performance of alternative BZ configurations on other assessment criteria

It is important to be aware that the aggregated costs for adjustments of BZ configurations, so-called one-off transition costs for TSOs, DSOs, market infrastructure providers, and stakeholders in the wholesale and retail segments, are not included in the shown SEW figures. Preliminary estimates from Compass Lexecon (2023) indicate that total transition costs for German BZ configurations range from about € 1200 to 1550 million for the DE2 configuration, and from about € 1250 to 2250 million for the DE4 configuration. For the NL2 configuration, total one-off transition costs amount to € 50 to 450 million. Note that the mentioned ranges of estimates are one-off costs while the SEW benefits are yearly recurring.

More broadly, the analysis of other effects than social welfare, CO_2 emissions, and robustness falls outside the scope of this study. In total, based upon EU legislation ACER (2020) elaborates upon 22 indicators for the assessment of alternative BZ configurations, including criterions such as network security, market concentration and market power in wholesale markets as well as redispatching mechanisms, and price signals for building network infrastructure as well as new generation or demand assets. Consequently, policy makers are advised to weigh the benefits of new BZ configurations in terms of increased SEW and reduced CO_2 emissions against the performance of alternative BZ configurations on the other assessment criteria to be considered for the BZR process.

Limitations of the study

Study limitations relate to assumptions concerning scenarios, network reduction method, and the COMPETES-TNO electricity market model. The five most important limitations are:

1. Since the generation and demand scenarios are a combination of national scenarios, they are not inherently consistent in some respects, for instance the application of different fuel and CO_2 price assumptions as well as assumptions concerning imports from neighbouring countries. This is most applicable to the

National Transition scenario which is based upon diverging National Energy and Climate Plan (NECPs) of EU Member States. Therefore, the results for this scenario could be less relevant for the assessment of the robustness of the BZ configurations.

2. One set of fuel and CO_2 prices was deployed for all scenarios. Another set of fuel and CO_2 prices could have an effect on both SEW results and CO_2 emissions as it might limit electricity price differences between Western Europe with high shares of low marginal cost generation (VRE and nuclear) and Eastern Europe with higher shares of high marginal cost generation (coal- and natural gas-fired generation). Consequently, generation dispatch might change and therefore CO_2 emissions.

3. The NR method constructs an equivalent reduced network that is closest to the real network but irrespective of where the added value of network capacity is highest. Herein we deviate from the flow-based market coupling method (FBMC) which offers flow-based capacity domains that allow for 'shifting' of available network capacities across zonal borders in case this improves social welfare. Nevertheless, we observe that the NR method makes additional grid capacity predominantly available on West-East interconnections which helps to reduce the most significant price differences between western and eastern European Member States. As such, the NR method seems to deliver results that are in line with the application of the FBMC approach.

4. The NR method does not allow for testing the contribution of bidding zones to the 70% requirement concerning the availability of network capacity for cross-zonal trading, since identification of non-scheduled flows (internal flows, loop flows) requires more granular network information, e.g., flows between two particular substations, than is offered by the reduced network representation. An alternative nodal model set-up requires nodal data of generation and demand, but given the lack of access to the nodal dataset from ENTSO-E as well as inadequate commercial and public databases this proved to be not feasible.

5. For the COMPETES-TNO model assumptions are made concerning the potential for electrification of demand for heat and hydrogen, which are derived from TYNDP-2022. In reality, there exist economic and social barriers that could prevent the realization of this potential.

1 Introduction

Decarbonisation of the electricity system increases the need for electricity transport
European and national policy targets for GHG-emission reduction for years 2030 and 2050 as well as renewable energy targets for 2030 drive the decarbonization of the electricity system. Electricity generation from variable renewable energy (VRE) such as solar and wind is more dispersed than conventional fossil-fueled generation and mostly located further away from load centers. Electrification of industry, built environment, mobility, and agriculture sectors with electric boilers, heat pumps, electric vehicles, and other technologies imply a larger share of electricity in total energy consumption as well as an increase of electricity demand in many locations across the electricity network compared to the current situation. As a result of both developments, directions of network flows change as well. Hence, the energy transition increases the need for electricity transport quite significantly across Northwestern Europe.

… and consequently the need for more efficient congestion management
Given that the energy transition is not a linear process but proceeds shock-wise (since cost reductions are not linear and market prices are highly variable) as well as the existence of alternative transition routes (e.g. heat networks in built environment, hydrogen deployment in industry and mobility sectors), it is difficult to predict the need for electricity transport with certainty. Furthermore, reinforcements of the transmission networks (high voltage grids), including interconnections, often take long lead times of 10 years or more. Consequently, network congestion is expected to increase significantly and therefore the need for more efficient congestion management.

Relevance of bidding zones for more efficient congestion management
The European electricity system is highly interconnected and allows for trading over wide areas in the European internal electricity market. The Netherlands is part of the CORE region, which consists of a large part of Continental Europe ranging from The Netherlands to Romania.[4] Most countries consist of one or more bidding zones,[5] which is defined as the area in which unlimited transport capacity for the market is available ("copper-plate" assumption). As a consequence, there is only one wholesale electricity price for each bidding zone. Different bidding zones show a different wholesale electricity price at times of congestion on one or more interconnectors between bidding zones. Introducing more bidding zones is a potential policy option to use the electricity network more efficiently; it allows electricity market prices to align better with physical reality and to provide better price signals to market participants for both new investment (e.g. location choice) and operational decisions. This may enable electricity from renewable sources such as wind and solar to be fed into the electricity system more effectively, while maintaining system security by limiting loop flows.

Regulatory context for research on bidding zones
The importance of bidding zones as a cornerstone of market-based electricity trading in Europe has been widely recognised by the European Commission, the European Parliament and the Council. EU regulations 2015/1222 and 2019/943 set out detailed rules for the review of bidding zone configurations. These detail how structural congestions should be identified and describe the process and assessment criteria to arrive at more efficient bidding zone configurations. Furthermore, EU regulation 2015/1222 indicates that the

[4] The CORE countries are Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxemburg, the Netherlands, Poland, Romania, Slovakia and Slovenia. These are all countries in Continental Europe that from together the CORE capacity calculation region which is applied for European electricity market coupling.
[5] An exception is Germany and Luxemburg which form together one bidding zone.

European Union Agency for the Cooperation of Energy Regulators (ACER) should assess the efficiency of current bidding zone configurations every three years based on, among other things, a technical report from the joint European TSOs as part of the European Network of Transmission System Operators for Electricity (ENTSO-E). Besides, EU regulation 2019/943 states that each EU Member State must comply with the requirement that at least 70% of grid capacity is available for cross-zonal trading by 1 January 2026. The remaining 30% can be used for reliability margins, loop flows and internal flows, and is therefore not related to cross-zonal trading.

As part of the most recent regular bidding zone review (BZR), in August 2022 ACER identified specific bidding zone configurations for examination by TSOs, including several alternative configurations for Germany and the Netherlands (ACER, 2022). The effects of these bidding zone configurations are currently being examined by the TSOs (according to the official planning of CORE region TSOs until December 2024) supported by ENTSO-E. The target year of the BZR analysis is legally set at 2025.

Reasons for this study and research question

However, the outlook for the Northwest European electricity markets offers a varied picture with moderate to strong growth in electricity demand and supply beyond 2025. This raises questions for the Dutch Ministry of Climate Policy and Green Growth about the robustness of the alternative bidding zone configurations in the medium term. Questions include the impacts of these bidding zone configurations compared to the status quo configuration on socio-economic welfare[6] and CO_2 emissions after 2025 as well as their robustness for a diverse set of scenarios concerning demand and supply developments towards 2035.

Therefore, this study aims to answer the following research question:

> *What are the effects of selected German and Dutch bidding zone configurations from ACER Decision 11-2022 on socio-economic welfare gains and CO_2 emissions of the CORE countries in 2035 compared to the current bidding zones, under different scenarios for electricity demand and supply?*

The answer to this question serves as an input to the Dutch Ministry of Climate and Green Growth for the expected decision of the relevant EU Member States to amend or maintain the current bidding zone configurations given Article 14(8) of EU Regulation 2019/943.

Scope of the study

Note that analysis of other effects than socio-economic welfare effects and CO_2 emissions falls outside the scope of this report. Hence, the performance of alternative bidding zone configurations on other assessment criteria like network security, market concentration and market power, price signals for building infrastructure, and the long-term effects on low-carbon investments are not included. For the full list of 22 indicators please refer to Article 33 of EU Regulation 2015/1222. These indicators have been further specified in Article 12 of Annex I of ACER Decision No 29/2020. When judging the study results, the reader should take this broader context into account.

Reading guide

The study is structured as follows. Chapter 2 describes the methodological approach that is applied for the analysis; the selection of BZ configurations, the COMPETES-TNO market model as well as the generation, demand and network assumptions that serve as model

[6] Welfare economics is the study of how the structure of markets and the allocation of economic goods and resources determine the overall well-being of society. Welfare economics seeks to evaluate the costs and benefits of changes to the economy and guide public policy toward increasing the total good of society. In the context of this study, socio-economic welfare is understood as the net benefits for society due to alternative bidding zone configurations i.e. the aggregation of the economic surpluses of electricity consumers, producers, and TSOs as transmission network owners (congestion revenue).

inputs. Subsequently, base case and project alternatives are discussed as well as the application of the socio-economic welfare methodology. Next, chapter 3 addresses the effects of generation redispatch[7] on socio-economic welfare and CO_2 emissions compared to a case that does not account for network congestion within a bidding zone. Once intra-zonal network congestion is disregarded in wholesale electricity markets, generation redispatch is needed to prevent that network congestion actually happens and thus distorts the secure functioning of electricity networks. The associated redispatch costs already occur with the current bidding zone configurations and therefore need to be included in the base case. Chapter 4 elaborates upon the socio-economic welfare and CO_2 emission reduction effects of new bidding zone configurations compared to the base case, as well as their robustness for different scenarios in 2035. This includes the effects for main stakeholders i.e. producers, consumers, and TSOs, in the CORE countries. Finally, Chapter 5 closes the study with conclusions for policy makers and suggestions for further research.

7

2 Methodology, data and assumptions

For assessing the effects of selected bidding zone (BZ) configurations, the following five step methodology is applied (see Figure 2.2):

1. **Selection of BZ configurations:** ACER (2022) identifies 14 alternative bidding zone (BZ) configurations (including fallback configurations) to be considered for the official BZR currently taking place at European level, for both the CORE region and the Nordic region (ACER, 2022). Three BZ configurations for the CORE region, for Germany and The Netherlands respectively, have been selected with the Dutch Ministry of Climate Policy and Green Growth for further research in this study, see Figure 2.1. These BZ configurations are considered most relevant for the Netherlands. Each individual BZ configuration is assessed against three 2035 scenarios to test its robustness against different possible supply and demand developments in the medium term. The analysis of effects of combinations of BZ configurations was outside the scope of this study;

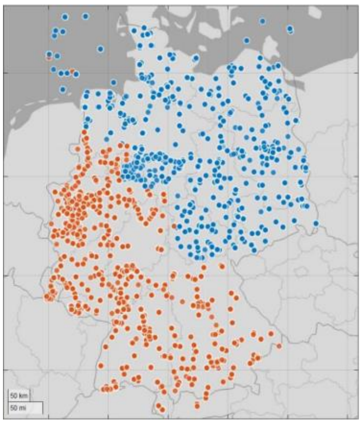
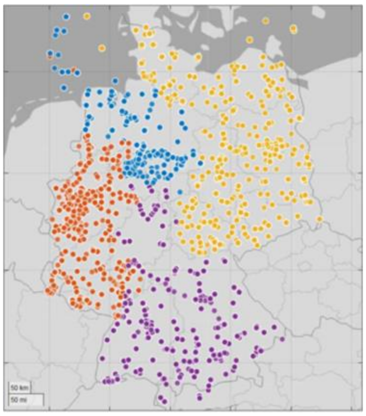
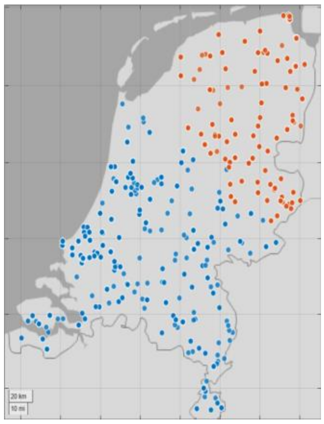
Bidding zone split DE into 2 zones (BZR ID 2)	Bidding zone split DE into 4 zones (BZR ID 13)	Bidding zone split NL into 2 zones (BZR ID 7)
		

Figure 2.1: ACER BZ configurations selected for assessment in this study

2. **Scenario framework**: to cover the wide range of possible supply and demand developments towards 2035, existing national scenarios for France, Germany, and the Netherlands have been reviewed and combined in three scenarios for multiple countries. Each new BZ configuration requires that supply and demand of the country involved is distributed across the bidding zones within the country (see Section 2.1);[8]
3. **Network reduction:** the Network Reduction (NR) method is introduced and applied to obtain a simplified, equivalent electricity network with transmission capacities and line susceptances for the different BZ configurations (see Section 2.3);
4. **Electricity market model runs** with the COMPETES-TNO electricity market model ('optimization model') to quantify amongst others the socio-economic welfare

[8] Given the lack of public data, for each scenario this distribution is based upon different sources and assumptions. For a detailed description of the distribution methods applied, see Appendix A.

(SEW) and CO_2 emission effects of each scenario and BZ configuration, taking into account the network parameters of step 3 (see Section 2.2);

5. **Analysis of incremental SEW and CO_2-emission effects**: these incremental effects are obtained by comparing alternative BZ configurations one-by-one against current country-based configurations corrected for redispatch costs. In this context, socio-economic welfare is understood as the net benefits for society due to alternative bidding zone configurations i.e. the aggregation of the economic surpluses of electricity consumers, producers, and TSOs as transmission network owners (congestion revenue). The robustness of the different BZs is tested by assessing the extent to which net effects are significant and move in the same direction under different scenarios for generation and demand taken from step 1. This provides insight in the extent to which alternative bidding zone configurations also make sense beyond 2025. The notions of socio-economic welfare and redispatch costs are further elaborated upon in Section 2.4.

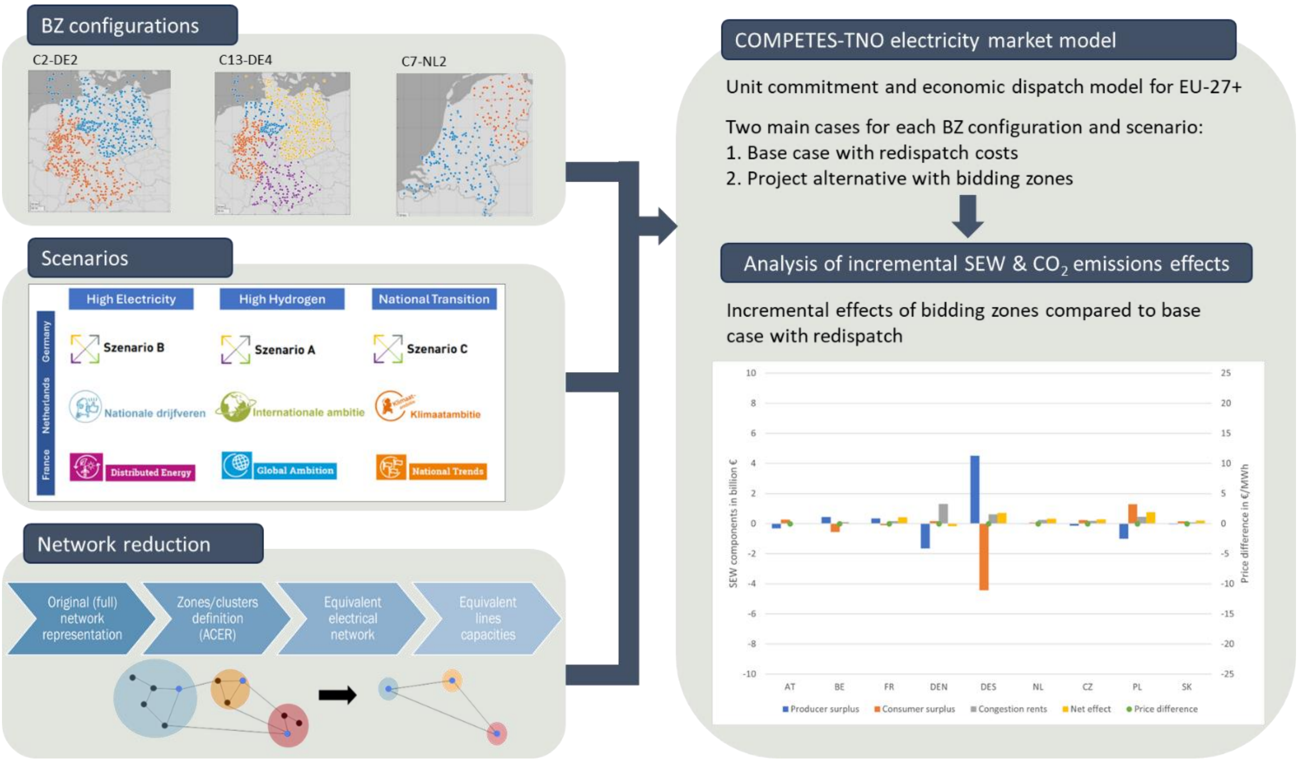


Figure 2.2: Methodological approach

2.1 Scenario framework

This study assesses proposed BZ configurations for Germany, and the Netherlands. For assessing the robustness of these BZ configurations for different possible generation and demand developments until the year 2035, three rather different scenarios were chosen. For Germany and the Netherlands, national scenarios were selected, as they align better to the expected situation in 2035 than European scenarios for the years 2030 and 2040. These scenarios are formulated in the 'Investeringsplannen' (IP2024) for the Netherlands (Netbeheer Nederland, 2023), and the 'Netzentwicklungsplan' (NEP23) for Germany (BNetzA, 2022). For France, given the absence of a suitable national scenario study for 2035, all three 'Ten-Year Development Plan' (TYNDP-22) scenarios are used (ENTSO-E&ENTSOG, 2022), as their national scenarios focus on the target year 2050. For all other EU Member States as well as Norway, Switzerland, and the UK, the 'National Trends' scenario from TYDNP-22 is selected as this concerns a base scenario from the electricity and gas TSOs that includes the

National Energy and Climate Plans (NECPs) and hence seems most suited to serve as a background scenario.[9]

The scenarios outlined by the NEP23 aim to achieve climate neutrality of the German electricity system by 2045, given national energy targets. Three scenarios are defined for the years 2037 and 2045:
- Scenario A: focuses on an increase on the use of hydrogen in the system.
- Scenario B: higher direct electrification is considered as well as a stronger energy efficiency improvement.
- Scenario C: while similar to Scenario B, it focuses on the direct electrification of sectors, but with lower energy efficiency and therefore more in line with current policies compared to previous scenarios, resulting in higher electricity consumption.

The TYNDP-22 scenarios applied to France follow different storylines:
- 'National Trends' (NT) is based on envisaged national climate policies of the different European countries.
- 'Distributed Energy' (DE) scenario has a decentralized approach to achieve the Paris agreement goals of both 55% reduction of worldwide GHG emissions in 2030 and climate neutrality in 2050. It focuses on electrification of demand and high deployment of variable renewable energy (VRE), such as solar PV.
- 'Global Ambition' (GA) scenario aims to achieve the Paris agreement through a more centralized production approach, with hydrogen playing a significant role in the decarbonization of the energy system, together with high international trade.

The IP2024 scenarios for the Netherlands have similar storyline structure as the TYNDP-22 scenarios:
- 'Klimaat Ambitie' (KA) is based on current energy and climate policies in the Netherlands.
- 'Nationale Drijfveren' (ND) ('National Drivers') relies on higher VRE capacities combined with higher electrification needs, with more distributed generation.
- 'Internationale Ambitie' (IA) focuses on the role of hydrogen and assumes both centralized-based production and well-developed international trade.

The scenarios for France, Germany, and the Netherlands are combined as outlined in Figure 2.3. The established scenario combinations aim to achieve consistency between the different storylines of the national scenarios as much as possible.

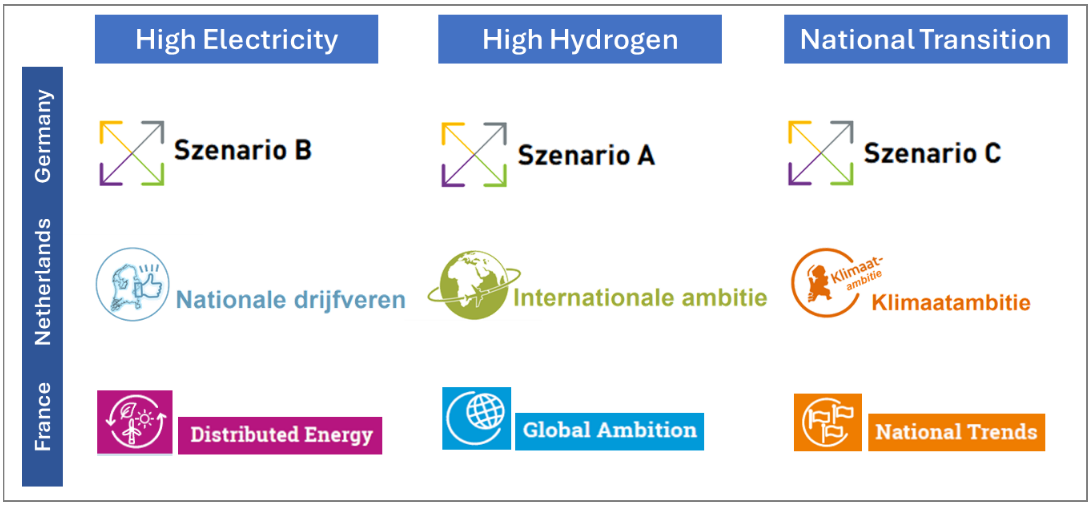


Figure 2.3: Scenario combinations analysed

9 This assumption is in line with IP2024.

The scenario combinations can be described as follows:

- Scenario High Electricity considers that the three countries show high shares of VRE and electricity demand. The latter is driven by electrification of industry and mobility sectors, following the respective storylines.
- Scenario High Hydrogen assumes lower direct electrification needs from the demand sectors in Germany and the Netherlands, and more indirect electrification by deployment of hydrogen. In France, this is combined with significantly more nuclear generation compared to the other scenarios.
- Scenario National Transition combines the national trends of the Germany, France, and the Netherlands as devised by the respective NEP23, TYNDP-22, and IP2024 scenarios. In line with current policy, this means a relative high demand in Germany compared to other scenarios. For France, it implies significantly lower wind and solar-pv generation capacities.

Hereafter the main scenario parameters are described; first the energy demand assumptions are discussed, followed by the energy supply assumptions.

2.1.1 Energy demand

The energy demand of the scenarios can be mainly classified as electricity and hydrogen demand respectively. It is important to note that both the TYNDP-22 scenarios and the NEP23 scenarios do not provide projections for the year 2035, which is the target year of this study. Hence, TYNDP figures are based on the target year 2040, while for the NEP23 projections from 2037 are taken. Since the TYNDP scenarios are somewhat less ambitious than the national scenarios concerning VRE penetration and demand electrification, we considered the electricity supply and demand figures for 2040 as representative for 2035.

The final electricity demand consists of inflexible base demand and flexible demand from different sectors (i.e. industry, mobility, agriculture, etc).

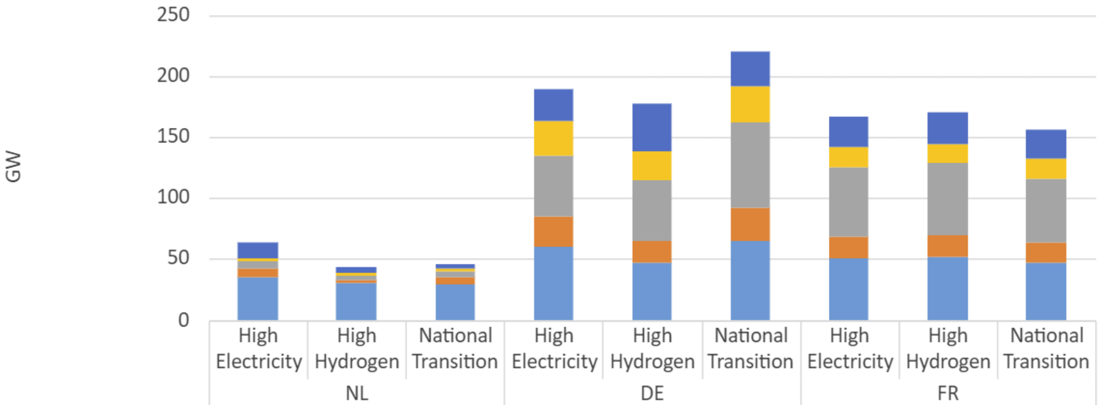
Concerning the mobility sector, there is flexible demand from electric vehicles which can shift their consumption pattern or act as battery storage, in response to electricity prices. In the residential sector, heat pumps also react to electricity prices, and shift their demand to hours with lower prices. For EVs and heat pumps, the shifting capabilities until 2035 are constraint due to behavioural and technical limitations. For heat pumps, we assume that from the total demand, only 5% is able to shift their consumption, and only for 2 hours can be delayed. For EVs, we make the assumption that on average 10% of the fleet is connected to the grid and can provide DR and Vehicle-to-Grid (V2G) capabilities.

In industry, flexible electricity demand relates to the deployment of hybrid e-boilers, which act as a load-shedding technology. This flexible demand for heat is commonly defined as Power-to-Heat or P2H. The operation of e-boilers depends both on electricity prices and the opportunity costs[10] of natural gas consumption. Another part of flexible demand relates to the deployment of electrolysers for the production of hydrogen, also referred to as Power-to-Hydrogen or P2H2. Given a certain H_2 demand, electrolysers are activated in case of low electricity prices, and turned-off when electricity prices surpass the willingness-to-pay of the electrolysers. Once electricity prices are too high, the H_2 demand must be met through other H_2 production sources, usually through Steam Methane Reforming (SMR), H_2 storage or imports. In this study, the hydrogen supply side is modelled in a simplified manner. Hence, hydrogen demand is fulfilled through either electrolysis or SMRs, taking into account installed electrolysis capacities and electricity prices. For more details on the modelling regarding Power-to-X, we refer to Appendix a.

[10] The opportunity cost of a choice is the value of the best alternative forgone where, given limited resources, a choice needs to be made between several mutually exclusive alternatives (Wikipedia).

The deployment of all flexible demand or conversion technologies relies on electricity prices, which are an outcome of electricity market modelling. The scenario assumptions and the modelling of demand response (flexibility) options and conversion technologies have been made as consistent as possible. However, deviations from the original electricity demand of the national and European scenarios may occur due to the optimization process as explained in Section 2.2.

The assumptions concerning inflexible base demand and flexible demand, for each analysed scenario are shown for Germany, France and the Netherlands in Figure 2.4.[11] Note that the hydrogen demand is highest in the High Hydrogen scenario (see Figure 2.5), but in Germany and France is satisfied by domestic production i.e. electrolysis while in the Netherlands it is largely fulfilled by hydrogen imports and to a lower extent by electrolysis. A more detailed explanation on the underlying assumptions for these figures is given in Appendix a, together with the figures for the remaining countries.



	NL			DE			FR		
	High Electricity	High Hydrogen	National Transition	High Electricity	High Hydrogen	National Transition	High Electricity	High Hydrogen	National Transition
Power-to-Hydrogen	14	6	4	26	40	28	24	26	24
Power-to-Heat	3	2	2	29	23	30	17	16	16
Heat Pumps	6	3	5	50	50	70	57	59	53
EVs	7	3	6	25	18	27	18	18	16
Inflexible demand	35	30	29	60	47	65	50	52	47

Figure 2.4: Electricity demand assumptions for Netherlands, France and Germany

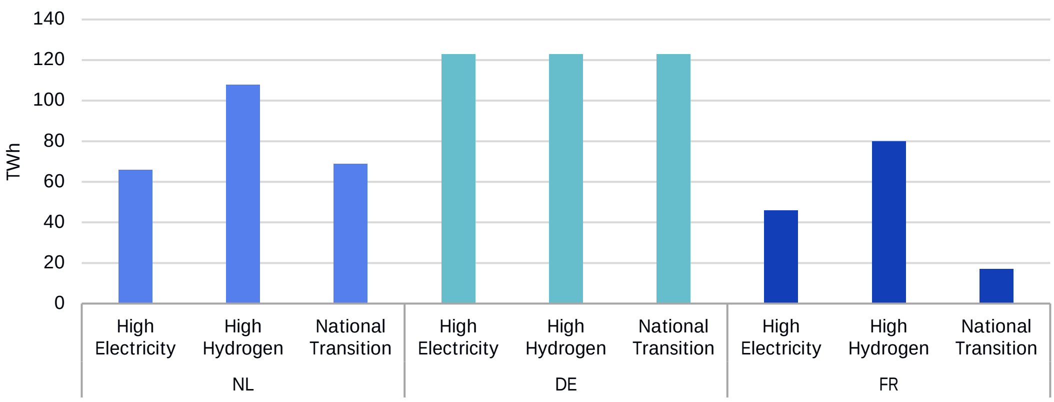


Figure 2.5: Hydrogen demand assumptions for the Netherlands, France and Germany

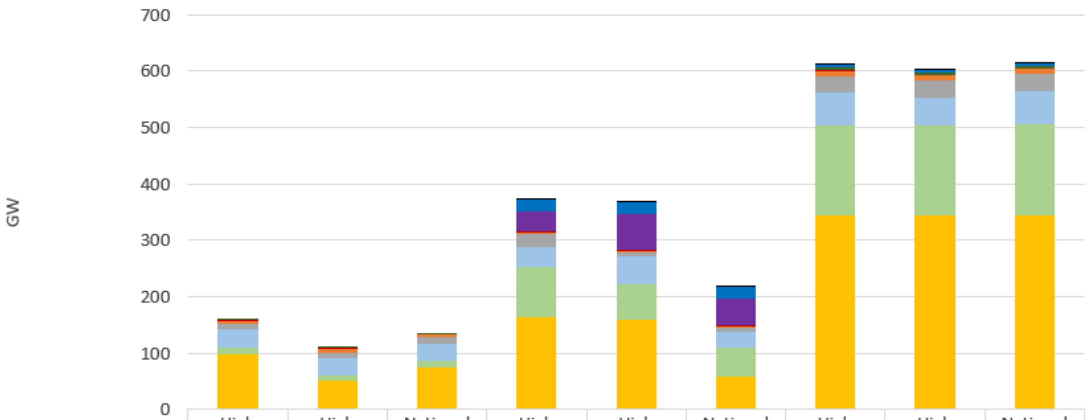
[11] For inflexible demand, heat pumps, and EVs, installed capacity is assumed to be equal to peak demand i.e. the maximum demand in an hour of the modelled year for the respective demand categories. For the Power-to-X technologies, installed capacity figures were readily available.

2.1.2 Energy supply

Installed capacities

Installed electricity generation capacities vary by scenario for the Netherlands, France and Germany. Figure 2.6 summarizes the generation capacities for the selected countries. For the total assumed installed capacities for the remaining countries, we refer to Appendix a. Table 2.1 shows the installed storage capacities of batteries as well as hydro pumped storage for the different scenarios.

It can be observed that generation capacities for France and the Netherlands vary more across the national scenarios than the generation capacities in Germany which are fairly constant across the scenarios. The National Transition scenario of France has about 150 GW lower generation capacity compared to the other scenarios, resulting mainly from lower VRE generation capacity. The High Electricity scenario is characterized by most VRE generation capacity as well natural gas-fired generation, while in the High Hydrogen scenario the natural gas-fired generation is replaced by significantly more nuclear generation capacity. For the Netherlands, the main variation between the scenarios results from different VRE capacities, as well as different assumptions on the conversion of natural gas-fired in hydrogen-fired power plants.



	High Electricity NL	High Hydrogen NL	National Transition NL	High Electricity FR	High Hydrogen FR	National Transition FR	High Electricity DE	High Hydrogen DE	National Transition DE
Other non-RES	0	0	0	1	1	2	1	1	1
Hydro	0	0	0	21	21	21	5	5	5
Biomass	0	0	0	0	0	0	5	5	5
Nuclear	1	1	1	36	62	47	0	0	0
Other RES	1	1	1	3	3	3	1	1	1
Hydrogen to power	6	9	4	1	3	2	10	10	10
Natural gas	10	8	12	24	7	7	29	29	29
Wind Offshore	32	31	31	35	48	27	59	51	59
Wind Onshore	13	8	11	89	64	53	158	158	162
Solar PV	98	53	76	164	159	58	345	345	345

Figure 2.6: Electricity generation capacities for the Netherlands, Germany and France in 2035 scenarios. Other non-RES includes oil, coal and lignite

Table 2.1: Electrical storage capacities for the Netherlands, France and Germany in 2035

	Netherlands			France			Germany		
[GW]	High Electricity	High Hydrogen	National Transition	High Electricity	High Hydrogen	National Transition	High Electricity	High Hydrogen	National Transition
Batteries	23	9	16	7	8	5	91	91	92
Hydro PS	0	0	0	7	7	7	12	12	12

Fuel and CO_2 prices

Fuel and CO_2 prices have a major impact on the deployment of distinguished generation technologies and hence are key parameters for this analysis (Table 2.2). Other types of generation costs, such as variable O&M and start-up costs, are reported in Appendix c.

Since the fuel prices of the TYNDP 2022 scenario are based upon the IEA World Energy Outlook 2020, they do not reflect the price increasing effect of the Russian invasion of Ukraine on natural gas prices. Hence, fuel prices are taken from the KEV 2022 (PBL *et al.* 2022), which is also most aligned with the Dutch context. Note that TYNDP 2024 scenarios were not yet available at the time fuel price assumptions had to be gathered for model runs. CO_2 price assumptions are also based on the KEV 2022 data.

An exception is the hydrogen price, which is obtained using a natural gas price factor. In recent reporting on simulations of a future hydrogen spot market, hydrogen prices are about two to three times as high as natural gas prices. The range reflects the cost of electricity as input costs for electrolysis, as well as import cost estimates for blue and green hydrogen ((TNO, HyXchange, Berenschot, 2024). In the TYNDP-22 NT scenario, this price ratio between natural gas and decarbonized H_2 is 2.4. We use this factor to obtain a H_2 price using the natural gas price of the KEV 2022, assuming that the H_2 used for power production will originate from electrolysis.

Table 2.2: Fuel and CO_2 prices assumptions

	Price 2035	Unit
Biomass	3.3	€$_{2023}$ / GJ
Coal	3.1	€$_{2023}$ / GJ
Lignite	1.5	€$_{2023}$ / GJ
Natural gas	13.4	€$_{2023}$ / GJ
Uranium	1.1	€$_{2023}$ / GJ
Oil	14.9	€$_{2023}$ / GJ
Hydrogen	32.1	€$_{2023}$ / GJ
CO_2	162.9	€$_{2023}$ / ton

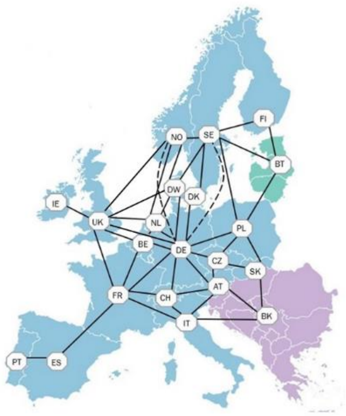
Source: PBL *et al.* (2022), adapted to €$_{2023}$

2.2 COMPETES-TNO model description

For this study, the electricity market model COMPETES-TNO is applied. COMPETES-TNO is a power system optimisation and economic dispatch model that seeks to meet European power demand at minimum social costs (maximizing social welfare) within a set of techno-economic constraints – including policy targets/restrictions – of power generation units and transmission interconnections across European countries and regions.[12]

Over the past two decades, COMPETES-TNO has been used for a large variety of assignments and studies on the Dutch and European electricity systems, the last years notably on the role of flexibility options such as electricity trade, demand response, and storage in systems with higher shares of electricity from variable and less predictable renewable generation.

The COMPETES-TNO model covers all EU Member States plus Norway, Switzerland, and the UK. The Balkan countries, i.e. EU Member States such as Bulgaria, Croatia, Greece, Hungary, Romania, and Slovenia, as well as countries that are still in the process to access the EU such as Albania, Bosnia and Herzegovina, Macedonia, Montenegro, Serbia, are grouped under a single Balkan region. The Baltic countries Lithuania, Latvia and Estonia are grouped under the Baltics region. Figure 2.7 shows the geographical coverage of the COMPETES-TNO model.



COMPETES-TNO consists of two main modules that can perform hourly simulations for two different purposes:

- *A transmission and generation capacity expansion module* in order to determine and analyse least-cost capacity expansion under perfect competition, formulated as a linear program to optimise generation capacity additions in the system;
- *A unit commitment and economic dispatch module* to determine and analyse least-cost unit commitment (UC) and economic dispatch under perfect competition, formulated as a relaxed mixed integer program considering flexibility constraints of generation units, and demand.

Figure 2.7: COMPETES-TNO geographical coverage and electricity interconnections

For the purpose of this study, the unit commitment module is applied in order to simulate day-ahead markets and redispatch. Since in practise flow-based market coupling is applied, and the effects of new bidding zone configurations are assessed in this context, implementing a decent physical network representation in COMPETES-TNO was deemed indispensable. A physical network representation means that electricity flows are distributed across different routes between countries or zones based on Kirchhoff's physical laws. This means that besides physical grid capacities also susceptances of network elements are taken into account. In order to keep the calculation times of the COMPETES-TNO model manageable, a simplified network representation is applied. This simplified network representation requires careful design so that it also realistically reflects the actual network when it comes to electricity transmission flows between bidding zones ('Network reduction (NR) methodology'). The NR methodology is an optimization approach which allows to obtain a simplified network that is as close as possible ('equivalent') to the original network concerning transmission capacities and line susceptances. A more detailed description of the Network Reduction approach is provided in Section 2.3.

At the same time, extending the model in one direction comes often at the price of disregarding other aspects in other to keep the model manageable. In this case, this means that the unit commitment module excludes certain features related to a hydrogen system that are included in the investment module. Notably the representation of a hydrogen

[12] Over the past two decades, COMPETES was originally developed by ECN Policy Studies – with the support of Prof. B. Hobbs of the Johns Hopkins University in Baltimore (USA). The COMPETES-TNO model is the successor to the COMPETES model. PBL developed the COMPETES model partially independent from TNO, their variant is called COMPETES-PBL model.

transmission system (imports/exports) as well as hydrogen storage are not modelled in this COMPETES-TNO model version, and therefore outside the scope of this study.

For each scenario year, the major inputs of COMPETES-TNO include parameters regarding the following exogenous parameters:

- Electricity demand across all European countries/regions, including inflexible base demand as well as flexible demand due to further sectoral electrification of the energy system by means of P2X technologies;
- Power generation technologies and transmission interconnections, including their techno-economic characteristics;[13]
- Flexibility options including their techno-economic characteristics:
  - Storage: Hydro Pumped Storage (PS) and Batteries
  - Trade: cross-border exports/imports
  - VRE curtailment
  - Electric Vehicles (EVs): load-shifting and storage capabilities from V2G and Grid-to-Vehicle
  - Power-to-Heat (P2H, industry): load shedding through hybrid (electric/gas) boilers
  - Heat Pumps (HP): load-shifting from all-electric heat pumps
  - Power-to-Hydrogen (P2H2): load shedding through electrolysers
- Hourly profiles of various electricity demand categories and renewable energy supply (RES) technologies (notably sun, wind and hydro), including the full load hours of these technologies;
- Assumed (policy-driven) installed capacities of RES power generation technologies;
- Expected future fuel and CO_2 prices;
- Policy targets/restrictions, such as meeting certain RES/GHG targets or forbidding the use of certain technologies (for instance, coal, nuclear or CCS).

On the other hand, for each scenario year and for each European country/region, the major outputs ('results') of COMPETES-TNO include:

- Socio-economic welfare (SEW) components, such as producer surplus, consumer surplus, and congestion rents
- Economic dispatch of the different generation units at hourly resolution for target year 2035
- Resulting CO_2 emissions of the power system
- Final electricity demand from flexible technologies
- Cross-zonal network flows resulting from electricity trading
- Hourly electricity prices.

For a more detailed description of the COMPETES-TNO model, we refer to Sijm et al. (2017) and Sijm et al. (2022).

2.3 Network reduction methodology

Originally, the COMPETES-TNO electricity market model contained a basic representation of physical flows, but often the version with net transfer capacities (NTC) without physical flow representation was deployed. For a more accurate representation of physical flows in the model, TNO considered several possibilities.

Employing a full network representation is impractical because of the computational burden. Moreover, a full network representation might not be possible due to the impossibility of getting confidential information, e.g., generators' techno-economic parameters and demand profiles at a nodal level. As stated in the Static Grid Model

[13] Except for ramping restrictions of HVDC cables.

Handbook of the Core Flow Flow-Based DA Capacity Calculation,[14] "*An example of extra data which cannot be published is the information about the generation units. Core TSOs are not owners of these data and cannot, therefore, publish them.*"

Hence, as part of an earlier research activity, a network reduction (NR) method was developed to create an equivalent system *as closely as possible* with the same electrical characteristics as the original one but with reduced computational effort and a lower required level of detail. Although this equivalent system should deliver comparable results to those of the original system for the required level of detail of this study, i.e., net positions, zonal prices, and social welfare, it has also some limitations. The main limitations of the NR method are:

1. The NR method constructs an equivalent reduced network irrespective of where the added value of network capacity for social welfare is highest. Herein we deviate from the flow-based market coupling (FBMC) method which offers flow-based capacity domains that allow for 'shifting' of available network capacities across zonal borders in case this improves socio-economic welfare.
2. The NR method does not allow for testing the contribution of bidding zones to the 70% requirement concerning the availability of network capacity for cross-zonal trading, since identification of non-scheduled flows (internal flows, loop flows) requires more granular network information, e.g., flows between two particular substations, than the reduced network representation offers.

The FBMC method was considered but not implemented for this study for two reasons. First, the COMPETES-TNO model is deployed in many TNO projects with a main focus on socio-economic welfare assessment and system optimization in the medium to long term rather than the short-term operational timeframe. As such, implementing a complicated method that can be deployed only limitedly was not considered as valuable. Second, and more important, application of the FBMC method to future scenario years is not straightforward since it requires information about locations of generation, load and network components, which is not available in the public domain.

During internal validation, the NR methodology was contrasted against FBMC net position curves from the IP2024 study for year 2035, showing that after some methodological improvements the NR methodology delivers results in the same ballpark as the FBMC method that is applied for the official bidding zone review (BZR). This is illustrated in Appendix b. Consequently, we applied the NR method to obtain network capacities for the CORE countries. Non-CORE countries were treated differently, with NTC values which were taken from ENTSO-E & ENTSOG (2022).

Figure 2.8 shows a graphical description of the NR method, which consists of four steps.

[14] See https://www.jao.eu/static-grid-model.

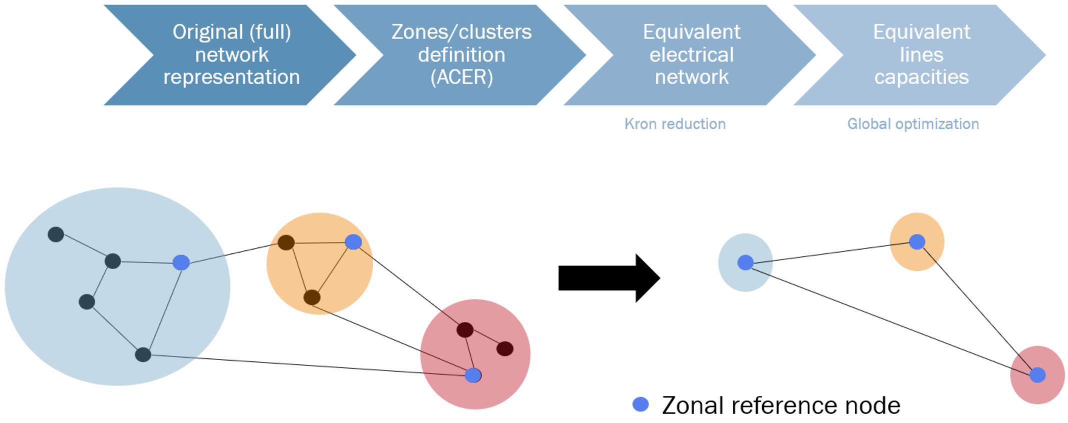


Figure 2.8: Network reduction graphical description

The four steps of the NR methodology can be described as follows:

1. **Original network representation:** We used the Core Static Grid Model released on 28/09/2023 as a starting point. This model contains all topological elements of the transmission system of our interest, including their electrical properties. An important parameter concerns transmission lines' and transformers' reactances. The list is published every six months by the Core TSOs in accordance with Article 25(2)(f) of ACER (2019a). Hence, the methodology can be replicated in the future. Expansion projects up to 2035 which were under construction or permitting phase from the TYNDP-22 expansion projects were included in our calculations. The list of included expansion projects can be found in Appendix b.

2. **Zones/Clusters definition:** ACER identified specific bidding zone configurations for examination by TSOs (ACER, 2022), including several configurations for Germany and the Netherlands. Taking the original network data, for each configuration to be tested each substation (hereafter referred to as a node) is linked to a bidding zone based on its location.

3. **Equivalent electrical network:**
   - **Kron reduction** was used in this project to obtain a reduced network due to its extensive use in the specialized literature and satisfactory results (Dorfler & Bullo, 2013). The Kron reduction uses the original network information, e.g., sending-receiving nodes and lines' electrical parameters (admittances). It obtains an electrically equivalent network after eliminating *non-desirable* nodes and keeping a set of *desirable* ones. The decision maker selects the nodes to be kept per bidding zone, which we call *representative nodes*. In this case, we used a heuristic decision based on the interconnection degree of each node in each zone (the number of connections a node has to other nodes in the network) to identify the representative nodes. The mathematical formulation of the Kron reduction can be found in Appendix b.
   - **Full network Total Transfer Capacity** (TTC) is the maximum power that can be transferred between pairs of zones in the original network, assuming that electricity exchanges in the rest of the grid (i.e., net positions in other bidding zones) are zero. TTCs are determined by adding power to one node and removing it from another until a network component reaches its limit, while considering the full network and its electrical characteristics (Kirchhoff's laws). The TTC between each pair of zones is obtained considering the N-1 criteria and calculated between a subset of the original nodes in each bidding zone using power transfer distribution factors (PTDFs). The

subset of nodes in each zone is an estimation of the location of generation and demand. Since this data is either confidential or unavailable, we used the S&P Platts Power in Europe database for allocation of generation and load to locations. The mathematical formulation to obtain the TTCs can be found in Appendix b.

4. Equivalent lines' capacities: The objective is that the equivalent line capacities of the reduced network produce TTCs that are *as similar as possible* to the full network TTCs between bidding zones. To do this, we solve an optimization problem. The solution to the problem provides all the line capacities that minimize the total squared difference between the TTCs of the full network between each pair of bidding zones and the TTCs of the reduced network between each pair of bidding zones. The formulation is written as a Mixed-Integer Quadratic Programming (MIQP) problem; thus, its global optimality is guaranteed. The flowchart of the methodology is shown in Figure 2.9.

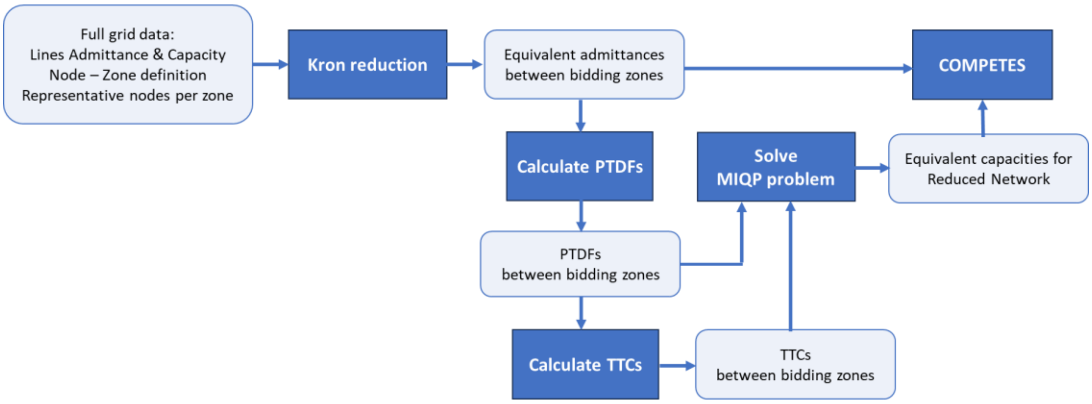


Figure 2.9: Flowchart of the full methodology

2.4 Analysis of incremental effects

This section first discusses the construction of the base case and project alternatives. Subsequently, the socio-economic welfare assessment methodology is explained.

2.4.1 Definition of base cases and project alternatives

The effects of the selected alternative bidding zone configurations ('project alternatives') are determined relative to the effects of the current bidding zones ('base case'). Hence, the analysis is based upon incremental or relative effects compared to current bidding zone configurations, rather than absolute effects of new bidding zone configurations. Therefore, we define three different cases:

1. The '**Country case**' reflects the status quo with country-based BZs (in the case of Germany this includes Luxemburg) and neglects redispatch costs. For electricity trading it is assumed that the grid is a copper-plate where intrazonal network constraints are fully disregarded. The operational security process taking place in reality to obtain an economic dispatch that takes into account network constraints has not been modelled. Therefore, redispatch costs are neglected in this case.

2. The '**Country case with redispatch**' accounts for the fact that in practise network capacities within zones are limited rather than unlimited as in the country case. Therefore dispatch of generation after closure of markets for electricity trading needs to be changed to guarantee that market transactions are feasible from network security perspective. This results in higher generation dispatch costs i.e. redispatch costs. Redispatch costs are defined as the costs of a measure that is activated by one or more TSOs by altering the generation, load pattern, or both, in order to change physical flows in

the electricity system and relieve a physical congestion. This case reflects the congestion issues within countries. A clear example is Germany, where there are severe transmission bottlenecks between North and South, which lead to significant redispatch actions and costs. Note that redispatch costs for structural congestion that is not related to the new bidding zone borders are disregarded. Hence, the calculated redispatch costs are limited to the costs of the intra-zonal network constraints that become cross-zonal network constraints with a new BZ configuration (see Section 3). The difference between '**Country case with redispatch'** and **'Country Case'** provides an estimation of the redispatch costs incurred by these specific transmission constraints.[15] The calculated effect is thus limited to the structural congestion within countries that is relieved by the new bidding zone borders.

3. The '**Bidding Zone case**' reflects the project alternatives i.e. the three proposed new BZ configurations for Germany, and The Netherlands respectively. The comparison of the 'Bidding Zone' case with the **base case** i.e. 'Country case with redispatch' provides the additional efficiency benefit of a more refined bidding zone configuration. The new BZ configurations price transactions on main transmission bottlenecks (formerly intrazonal constraints) and thus relieve more available transmission capacities for cross-zonal trading.[16] This results in more efficient generation dispatch in each of the project alternatives compared to the base case.

The **'Country case with redispatch'** is considered as the **base case** for this report. Since redispatch costs in the base case are calculated based upon the new bidding zone borders, these costs will vary by BZ configuration, requiring a separate base case for each configuration.

The effects of the BZ project alternatives are then compared to this base case for two evaluation criteria:
- Socio-economic welfare i.e. the sum of producer surplus, consumer surplus, and congestion rents;
- CO_2 emissions from the power system.

Note that the BZR has a broader scope as it assesses 22 different evaluation criteria that are part of four main categories to assess effects on network security, market efficiency, stability and robustness of BZs, and energy transition respectively. For the full list of indicators please refer to Article 33 of EU Regulation 2015/1222. The assessment of social welfare is part of the evaluation of the economic efficiency criterion which is the first step of the performance assessment of alternative BZ configurations and as such is key for the overall assessment. The box below summarizes insights about the indicator transaction costs from Compass Lexecon (2023).

[15] The approach to quantify the redispatch effect is based upon differences in generation dispatch derived from an electricity market model and therefore called a market-based method. This type of approach is also followed for the official European bidding zone review by the Nordic countries. It differs from the network-based redispatch method that is applied for the official European bidding zone review in the CORE region, where the need for redispatch is determined with a more detailed network model.

[16] This can also be understood as an additional degree of freedom in modelling i.e. once network congestion is priced on more borders, this allows to optimize network capacities closer to physical limits.

Box 2.1 Transition costs

One of the criteria is to assess transition costs i.e. the costs of implementing alternative bidding zone configurations. Compass Lexecon (2023) performed a study for ENTSO-E on transition costs.

Transition costs are estimated following the definition given by ACER in article 15.11 (a) of the BZR methodology (ACER, 2020). In short, transition costs are one-off costs, expected to be incurred in case the BZ configuration is amended and which concern adaptations that are inherently and unambiguously related to a specific BZ configuration change.

Compass Lexicon (2023) estimates that total transition costs for German BZ configurations range from about € 1200 to 1550 million for the DE2 configuration, and from about € 1250 to 2250 million for the DE4 configuration. Total transition costs for the NL2 BZ configuration amount to € 50 to 450 million.

Total transition costs are the sum of the aggregated transition costs of DSO, TSOs, market infrastructure providers (e.g. Nominated Electricity Market Operators (NEMOs), derivative exchanges, clearing houses) and stakeholders in the wholesale and retail segments. Total costs are mainly driven by IT system costs and internal business processes costs, and to a lesser extent costs associated with the re-negotiation or termination of contracts.

Limitations include data quality as data has been collected from questionnaires to stakeholders with voluntary provided costs estimates and data that was not subject to an audit apart from normal plausibility tests. Besides, some costs were not considered as transition cost following the ACER definition above. This includes changes to devaluation of assets due to price changes as well as opportunity costs of the postponed introduction of new mechanisms or products by market infrastructure providers. Furthermore, data was gathered from a limited number of stakeholders and is not necessarily representative. Hence, the provided ranges are a ballpark range rather than an error margin.

Finally, note that the mentioned ranges of differing estimates are one-off costs while the SEW benefits are yearly recurring costs.

Effects of BZ configurations on CO_2 emissions are part of the assessment of all other criteria in step 2 (see article 13 of Annex I of ACER, 2020).

Changes of social welfare and CO_2 emissions originate from changes in underlying parameters such as generation mix, demand response deployment, electricity imports and exports, and electricity prices. Hence, these parameters are part of the discussion of the incremental effects.

The approach to obtain the incremental SEW effects of alternative BZ configurations consists of two steps and is summarized in Figure 2.10.

First, the increase of generation dispatch and flexible demand costs (‘redispatch costs’) due to consideration of a number of important network constraints is calculated in order to obtain base cases that include redispatch costs. Note that the subset of intra-zonal network constraints that necessitate redispatch are the same as the additional cross-zonal network constraints of an alternative BZ configuration. From a modelling perspective with a market setup with one wholesale electricity market rather than a two-staged market with separate wholesale and redispatch markets as in practise, and given perfect competition, the reflection of network constraints in either redispatch market or wholesale market does have equal physical and monetary effects on generation dispatch, wholesale electricity prices, and thus on socio-economic welfare.

Second, the socio-economic welfare effects of alternative BZ configurations are calculated against the base cases. The alternative BZ configurations ('project alternatives') allow for more available interconnection capacity and therefore a more efficient electricity network that enables more electricity trading, price convergence across bidding zones, and consequently SEW gains compared to the base cases. This SEW gain can also be regarded as a reduction of redispatch costs.

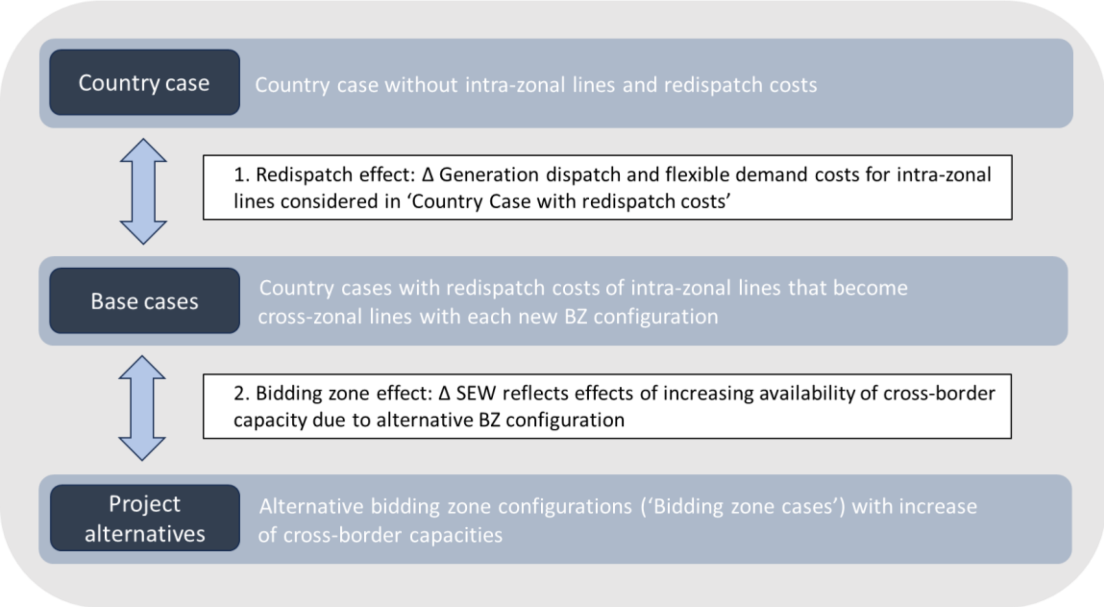


Figure 2.10: Base cases and project alternatives to obtain incremental effects of new bidding zone configurations

2.4.2 Socio-economic welfare assessment methodology

The concept of socio-economic welfare is well-known from micro-economic textbooks. In this study, it is applied to obtain the social welfare increase of bidding zones in the form of more available interconnection capacity.

Figure 2.11 provides an example of the social welfare effects of electricity trading for two random interconnected countries or bidding zones. For a given hour, the net export or net import curve of each market is constructed from its demand and supply curves. Once supply exceeds demand there is a net export of country A, with at the same time demand exceeding supply and therefore a net import of country B.

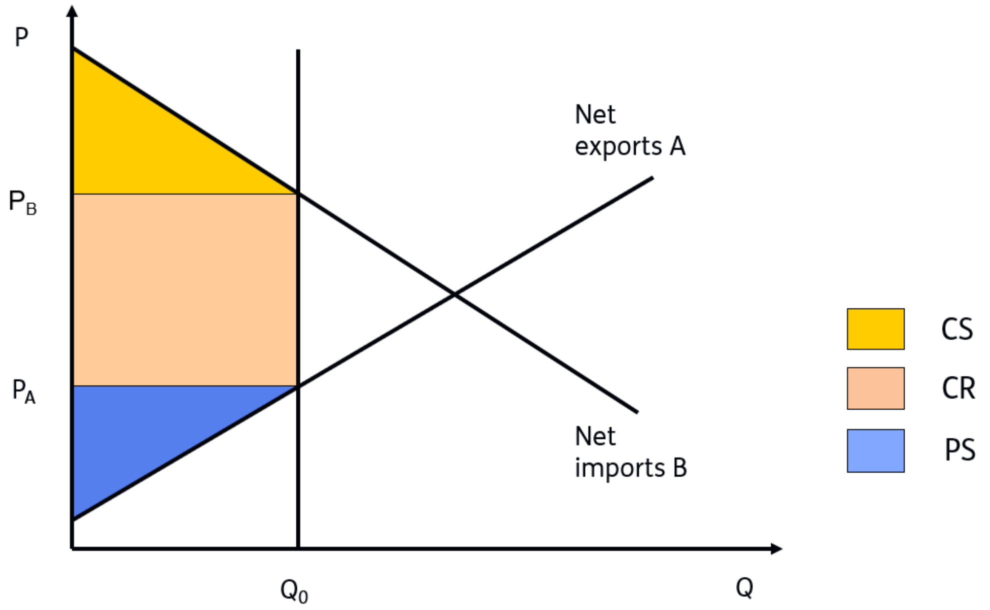


Figure 2.11: Social welfare effects due to electricity trading in the base case

Socio-economic welfare basically consists of producer surplus, consumer surplus, and congestion rents:

- Producer surplus (PS) is the difference between price (P_A) and the marginal cost curve (or the supply of net exports of country A) and is equal to the blue area for country A. It constitutes profits for producers with marginal cost smaller than price ('inframarginal rents');
- Consumer surplus (CS) is the difference between the demand curve which represents the willingness-to-pay of consumers (or the demand for net imports of country B) and price (P_B), and is equal to the yellow area for country B;
- Congestion rents (CR) is the price difference between countries A and B (P_B-P_A), multiplied by the quantity produced and consumed at (Q_0), and is equal to the pink area. Electricity trading is limited by available cross-zonal network capacity Q_0. Usually congestion rents are equally shared between TSOs as owners of a specific interconnection.

For simplicity, Figure 2.11 assumes that total demand is inflexible, hence the demand curve is vertical. The COMPETES-TNO market model includes flexible demand though, hence the lower part of the demand curve is not vertical, but downward sloping (with horizontal steps).

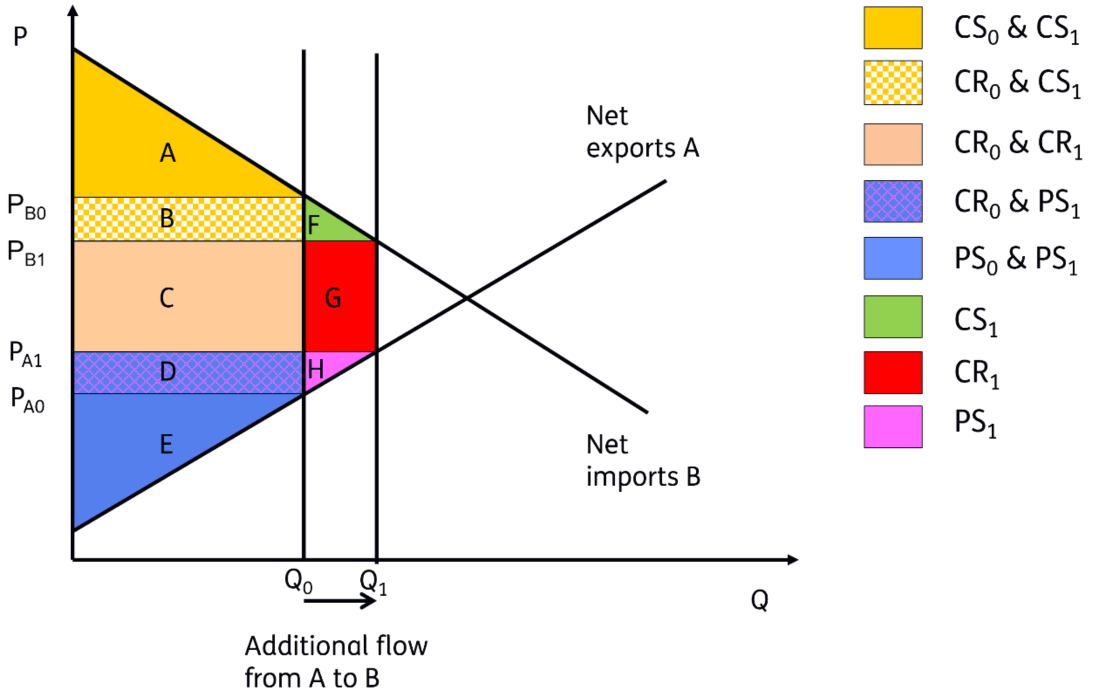


Figure 2.12: Changes in social welfare effects due to the project alternative with more opportunities for electricity trading

In Figure 2.12, social welfare effects of two situations are shown; a base case situation (with subscript 0) and the project alternative with bidding zones (with subscript 1).

The base case situation can be described as follows:

- Producer surplus is again the difference between price (A_0) and the supply or net exports curve and equal to area E for country A;
- Consumer surplus is the difference between the demand curve or net imports curve which represents the willingness-to-pay of consumers and price (B_0), and equal to area A for country B;
- Congestion rents is the price difference between countries A and B, multiplied by the quantity produced and consumed (Q_0), and equal to areas B, C, and D.

More available interconnection capacity due to bidding zones causes the following incremental effects of the project alternative compared to the base case ($Q_0 \rightarrow Q_1$):

- Producer surplus: areas E+D+H (country A)
- Consumer surplus: areas A+B+F (country B)
- Congestion rents: areas C+G (country A and B).

The gross benefits of more available interconnection capacity for society are equal to areas F, G, and H. It concerns gross benefits because the cost of introducing an alternative BZ configuration still needs to be deducted from the benefits. Remaining changes are redistribution effects which do not change the social welfare results; B and D originally were congestion rents and change to consumer surplus and producer surplus respectively.

3 Effects of redispatch

As outlined before, the approach to obtain the incremental socio-economic welfare effects of selected alternative bidding zone configurations ('project alternatives') consists of two steps (see Figure 2.10). First, the redispatch costs and associated effects are calculated in order to obtain base cases that include redispatch costs. Redispatch costs are defined as the costs of a measure that is activated by one or more TSOs by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion. Generation redispatch means switching off cheaper power plants that contribute to network congestion in certain locations, and switching on more expensive power plants on other locations that help to relieve network congestion. This constitutes a daily process organized by the TSOs. Second, the socio-economic welfare effects of alternative BZ configurations are calculated against the base cases.

This Chapter reports about the first step i.e. the calculation of redispatch costs and shows the incremental effects of including redispatch costs in the base case. As such, this Chapter serves as an intermediate but necessary step for the discussion of the incremental effects of alternative bidding zone configurations in Chapter 4. The redispatch costs require proper discussion since they indirectly determine the incremental effects of bidding zones. In case the effects of redispatch would not be adequately taken into account, this means that the real generation costs of the base case are underestimated, which leads to negative incremental effects of the project alternatives. Therefore, properly taking into account redispatch costs in the analysis of effects of bidding zones is indispensable.

Our redispatch assumptions deviate to some extent from the official bidding zone review (BZR) and probably imply underestimation of actual redispatch costs in 2035 for three reasons:

a) Redispatch costs are limited to the costs of those intra-zonal critical branches that become cross-zonal branches with a new BZ configuration, and in contrast with the BZR performed by ENTSO-E disregard redispatch costs of other intra-zonal critical branches. Hence, the redispatch volume considered in this study is smaller than in the BZR;
b) All power plants and flexible demand facilities are assumed to be available to participate in the redispatch process, while in the official BZR the number of power plants available for redispatch is limited for technical reasons, potentially giving rise to higher redispatch costs in BZR than in this analysis;
c) We assume that flexibility providers do not dispose of market power (implicitly assuming conditions for perfect competition are fulfilled). Furthermore, we assume that given price arbitrage across day-ahead and redispatch markets generators bid the opportunity costs of redispatch in the day-ahead market. This comes down to flexibility providers bidding up to the marginal bid, especially in case of recurring congestion situations. Given the repetitive nature of short-term electricity markets, bidder may learn what the typical marginal bid is. The pay-as-bid nature of the redispatch market then offers additional margin ('contribution margin') to flexibility providers if they bid up to the typical marginal offer, so that market clearing converges to pay-as-cleared solutions (Neon and Consentec, 2019). See Box 3.1 for more details about the price assumptions for redispatch. Our approach differs from the BZR which assumes the marginal costs of generators plus a markup. This may result in different amounts of redispatch costs, which depending on the markup of the BZR may result in either higher or lower redispatch costs in this study.

Furthermore, like the BZR this study assumes cross-border rather than national redispatch. Although cross-border redispatch is not yet current practice, given the European-wide methods that are developed following articles 35 and 74 of EC (2015) this should definitely be standing practice by 2035. This implies that generation units (and flexible demand facilities) from other EU Member States can also be deployed for redispatch purposes, reducing the redispatch costs compared to current country-based redispatch.

Box 3.1 Calculation of redispatch costs assuming an uniform market clearing price

Currently, redispatch costs are usually determined on a pay-as-bid basis. This is likely to change in the future, since EU-wide coordinated redispatching and countertrading is obliged by article 35 of EU Regulation 2015/1222. Therefore cross-border redispatch that reckons on bilateral transactions is hardly imaginable to sustain given the multilateral scope of such a scheme as well as the need for fast central market clearing for risk management purposes (amongst others to limit the counterparty risks involved with bilateral trading).

Generally in a market with free bids and pay-as-bid, players would try to place their bids as close as possible to the price of the last accepted bid - so prices converge to the uniform clearing price even for pay-as-bid (Hirth et al., 2019). This phenomenon is particularly likely to occur in case of structural congestion, like those targeted with alternative bidding zone configurations. As structural congestion should show to be repetitive by nature, this allows market parties to anticipate whether the price on the redispatch market is below or above the zonal price (i.e. through probe the redispatch market).

Further, the aforementioned authors argue in their analysis that pay-as-bid should not be confused with bidding mere costs. Price arbitrage between day-ahead electricity market and subsequent redispatch market allows producers to take advantage of differences between the spatial granularity of the electricity market (e.g. day-ahead market) as well as of the redispatch market (respectively for zone as a whole versus per node). This allows generators to take opportunity costs of the redispatch market into account in their bids and hence to make profits with the inc/dec game. Consequently, TSOs are confronted with bids to compensate producers not only for their costs but also for their opportunity costs.

In the same contribution, Hirth et al. (2019) argue that such price arbitrage is a rational bidding strategy (‘Nash equilibrium’) which does not require market power to be pursued, as theoretically shown in Hirth & Schlecht (2019). Conversely, not taking price arbitrage into account for redispatch actions is not rational and not a Nash equilibrium. Concerning the latter, they give the example that gas-fired power plants in scarcity regions such as Southern Germany are able to earn more money in the redispatch market, hence it is irrational if they do not to take this opportunity into account in their bids for the day-ahead market. Likewise producers in surplus regions such Northern Germany can earn profits by price arbitrage. It is sufficient for market players to correctly anticipate whether the price on the redispatch market is below or above the zonal price. This is possible for a bidding zone with structural congestion such as the alternative German bidding zone configurations (DE2 and DE4). This may not hold for the Dutch bidding zone though, where congestion seems typically driven by reinforcement projects and thus is of a more temporary nature so that congestion occurrences may prove hard to predict effectively in order to bid in opportunity costs.

However, given that in reality redispatch markets are prone to market power, it is unlikely that this will result in significant overestimation of the actual redispatch costs in the Netherlands. Moreover, the alternative means assuming that producers bid their marginal costs only, which is quite unlikely for three reasons. First, it this does not provide any benefit for producers for taking part in redispatch (contribution margin of zero), which is irrational and does not constitute a Nash equilibrium as shown by Hirth & Schlecht (2019). Second, the Netherlands applies a market-based redispatch scheme that allows producers to bid in their opportunity costs, although the remuneration is maximised per congestion area. Third, given that the German network is characterised by structural congestion, it is likely that generators will perform price arbitrage and thus bid their opportunity costs. As a conclusion, the electricity price for the redispatch case is considered as applicable to all redispatch actions.

Table 3.1 summarizes the increases of redispatch costs for each BZ configuration. The redispatch costs differ between BZ configurations since each project alternative mitigates a different situation with network congestion. Hence, redispatch costs are calculated for only one additional border for the DE2 and NL2 BZ configurations, although at different locations, while in the DE4 BZ configuration redispatch costs are calculated for three new borders. This increase of redispatch costs equals the decrease of socio-economic welfare for each configuration and scenario (see ENTSO-E, 2023).[17]

Table 3.1: Redispatch costs in the base case compared to country case without redispatch for EU-27+ in 2035

BZ configuration	High Electricity	High Hydrogen	National Transition
	(M€/year)	(M€/year)	(M€/year)
DE2	2882	1640	4300
DE4	2981	1972	4456
NL2	20	17	29

The redispatch costs of the alternative BZ configurations can be generally explained as follows:

- Generation mix change with lower VRE output due to higher curtailment levels, and more production from dispatchable generation, such as nuclear, gas, and biomass. This is a direct result of the higher number of network constraints that is accounted for in the power system optimization.
- Imports and exports change once more network constraints are accounted for. Usually, less electricity can be exported from a surplus area to a deficit area within the country (Germany or the Netherlands) that is affected by the North-South network constraint. Consequently, the deficit area needs to fulfil its demand by more imports from other countries and/or higher electricity production in its own area.
- The deployment of dispatchable generation, which are more expensive generators, increases implicit electricity prices i.e. wholesale electricity prices including redispatch costs, which results in a decrease of deployment of conversion options, like electrolysis and electric boilers in industry.
- CO_2 emissions of the power system increase with the deployment of fossil-fuel generation. Some countries exhibit a small decrease of CO_2 emission due to overall changes in net positions given cross-border redispatch.

As can be observed, the National Transition scenario presents the highest redispatch costs across the analysed configurations, whereas High Hydrogen shows the lowest. This can be explained by the larger differences between supply and demand in the former scenario, which means overall highest electricity price levels and with that also price changes due to redispatch actions. This translates into largest changes of flexible demand such as less deployment of P2H i.e. lower electricity consumption of hybrid boilers as well as less hydrogen production from electrolysis.

Results are discussed in more detail per BZ configuration in the sections below.

[17] ENTSO-E (2023) provides a proof of this equality for price-inelastic demand. Once price-elastic demand i.e. flexible demand is taken into account, it can be derived that the SEW difference is equal to the increase of generation dispatch costs ('redispatch costs') minus the willingness-to-pay times the change in demand between the cases with and without redispatch costs.

3.1 DE2 BZ configuration

Once network constraints between Northern and Southern Germany are taken into account in market optimization this results in the following socio-economic welfare effects;

- Increase of **producer surplus** because generators' profits increase with deployment of more expensive generators for redispatch. Hence, implicit wholesale electricity prices reflecting redispatch costs increase. As explained before, generators are compensated for their opportunity costs, given lack of market power and pay-as-bid assumptions.
- Decrease of **consumer surplus** since higher generation costs due to redispatch imply higher implicit electricity prices and lower deployment of flexible demand. Note that energy costs related to natural gas consumption of hybrid boilers and SMRs fall outside electricity system boundaries and thus are not included in costs and SEW changes.
- **Congestion rents** increase due to the additional congestion income that TSOs earn on the German North-South cross-zonal border as well as an increase of implicit electricity prices. Although the quantity traded and sold in the wholesale electricity market remains the same, implicit wholesale electricity prices increase with a more expensive generation dispatch and therefore the congestion rents. In practice, these redispatch costs will not be recovered by higher electricity prices but by network tariffs. In addition, since cross-border redispatch is taking place to relieve congestion between Germany-North and South, German TSOs will have to pay other countries for the deployment of generators for redispatch. This is in line with the polluter-pays principle for remuneration of the costs of cross-border redispatch that is strived for at European level (article 16 of EC (2015)). This is likely to result in higher network tariffs in Germany, which will be socialized to German consumers.

Effects of accounting for redispatch costs on SEW components are shown by country in Figure 3.1-Figure 3.3 below, and effects on CO_2 emissions in Figure 3.4. Effects on (implicit) electricity prices are shown in Figure 3.8-Figure 3.10.

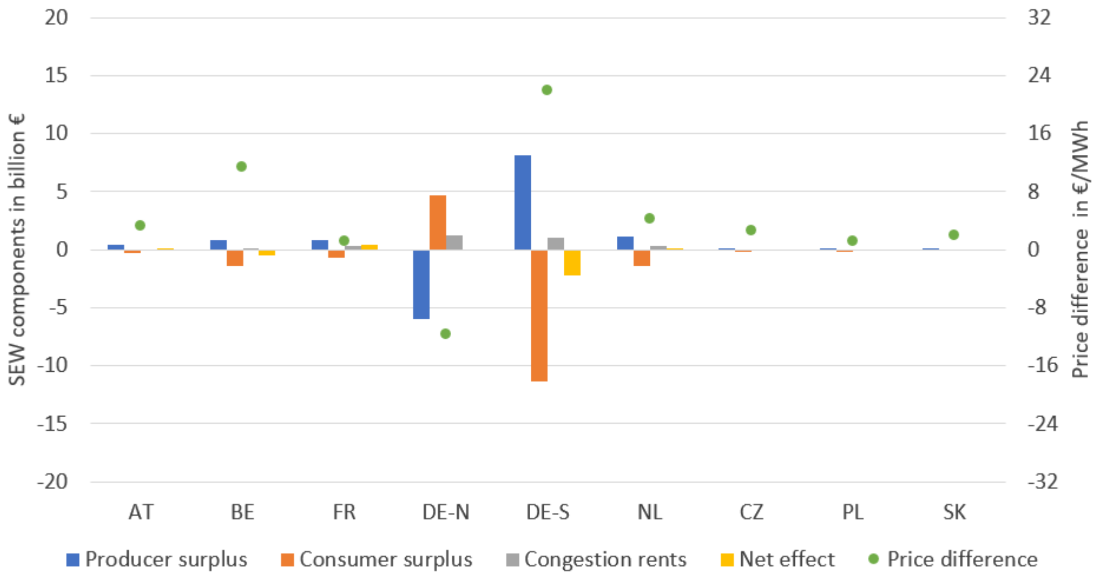


Figure 3.1: Incremental SEW effects due to redispatch for the CORE countries in the High Electricity scenario

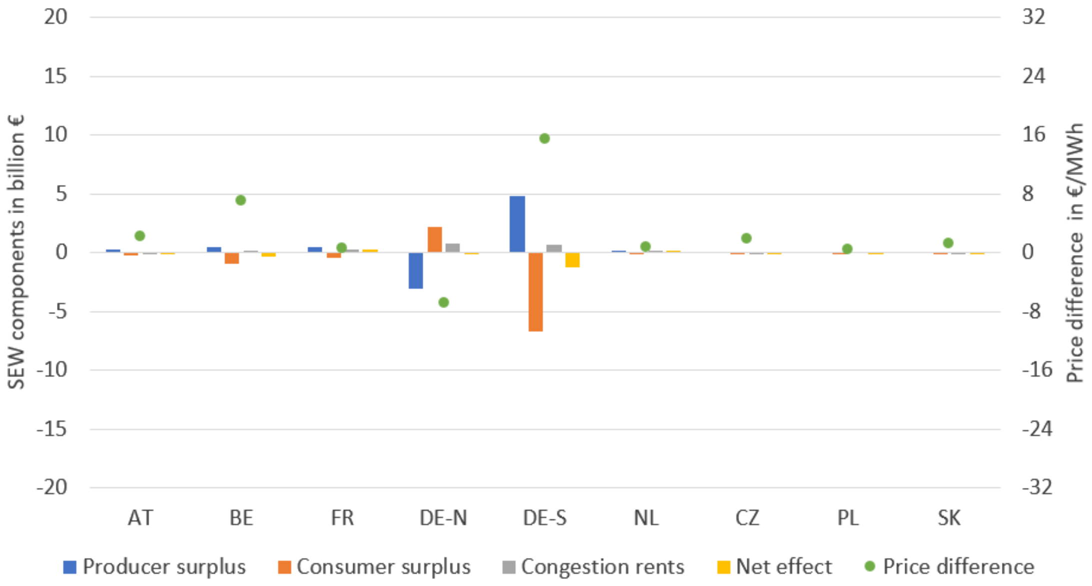


Figure 3.2: Incremental SEW effects due to redispatch for the CORE countries in the High Hydrogen scenario

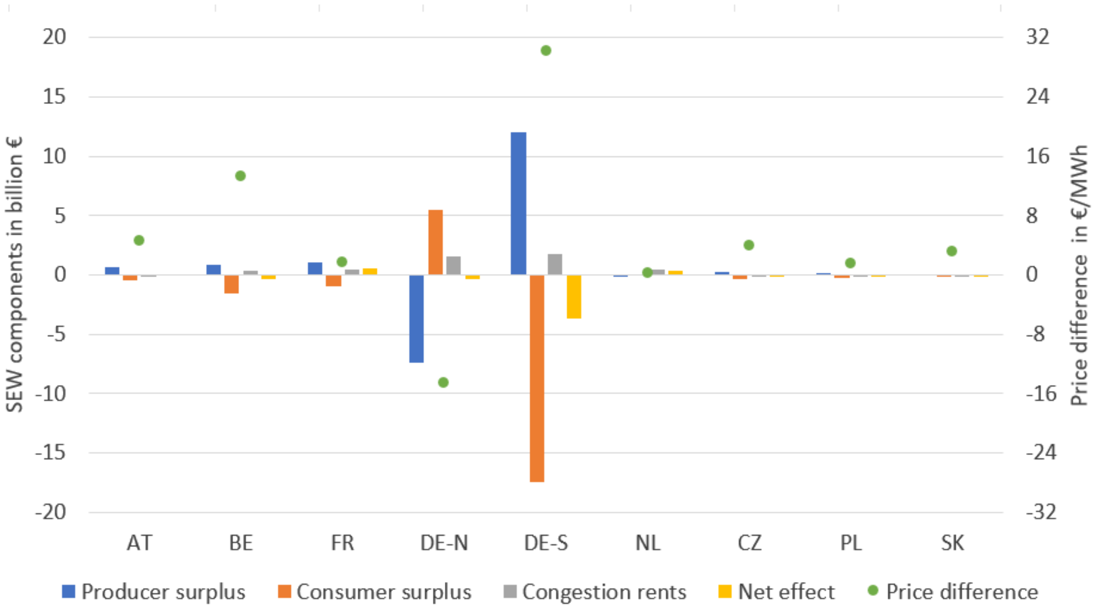


Figure 3.3: Incremental SEW effects due to redispatch for the CORE countries in the National Transition scenario

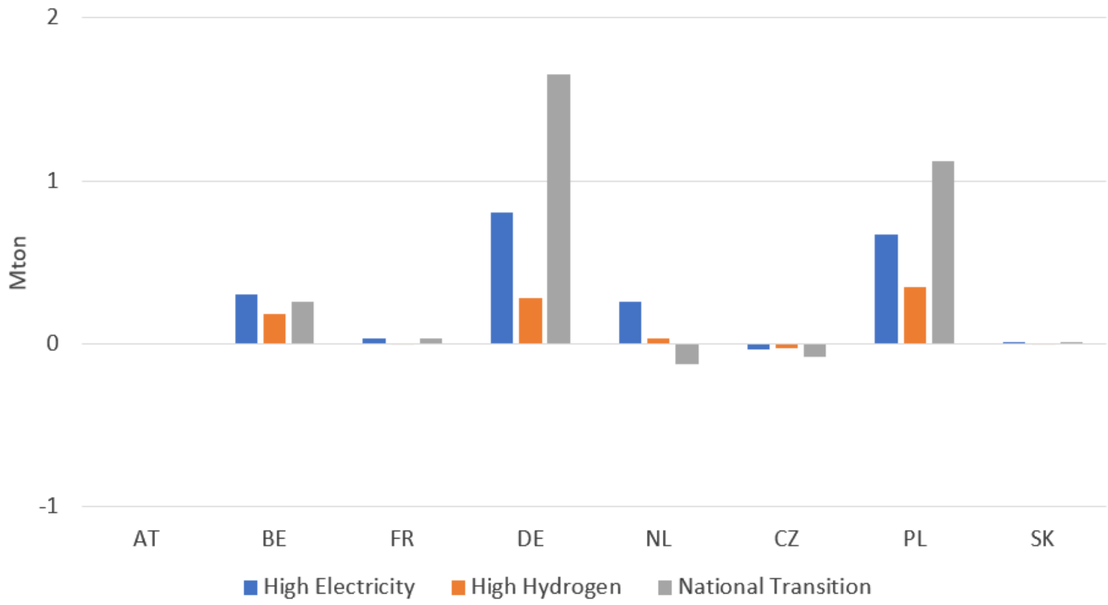


Figure 3.4: Changes in CO_2 emissions of the CORE countries due to redispatch

The increase in redispatch costs across scenarios occurs for the following reasons, which are linked to the trends mentioned above:

- The generation mix changes especially in Germany. Less electricity from wind can be transported from Northern to Southern Germany, increasing overall wind curtailment and notably curtailment in Germany North (DE-N). There is also a bit less electricity production from biomass-fired generation. Electricity production in Germany South (DE-S), France (FR) and The Netherlands (NL) (except for National Transition scenario) increases a bit, in Germany South amongst others due to less curtailment of wind. See Figure 3.5 for more details.
- Once electricity production in DE-N declines, Germany South (DE-S) imports less from Germany North and increases its domestic electricity production. Apart from the CORE countries shown in Figure 3.7, significant effects are also visible in Denmark (DK), Sweden (SE), and the UK (in total per scenario 9-18 TWh less generation). Once German North-South network limitations are accounted for, the economic viability of exporting electricity decreases for these countries.
- Total demand in EU-27+ decreases compared to the case where redispatch costs are not taken into account. Deployment of more expensive generators increases implicit electricity prices, i.e. wholesale electricity prices including redispatch costs, decreasing flexible demand. These decreases are mainly due to lower P2H deployment and to a more limited extent due to lower P2H2 deployment. Electricity consumption of hybrid boilers is replaced by gas consumption for more hours during the year. Likewise, hydrogen production from electrolysis is replaced by production from SMR once implicit electricity prices increase. The decline of demand is about 15 and 35 TWh in High Hydrogen and National Transition scenario respectively, with High Electricity within this bandwidth, see Figure 3.6. Electricity consumption decreases not only in Germany, France, and the Netherlands, but also in other CORE countries such as Belgium, Czech Republic, Poland, Balkan, and Austria. Despite the lower deployment of flexible demand, its redispatch costs increase significantly due to the higher (implicit) wholesale electricity prices. Flexible demand accounts for 75-80% of the total redispatch costs per scenario, with the remainder being the increase of generation dispatch costs. Hence, results are sensitive for flexible demand assumptions made.

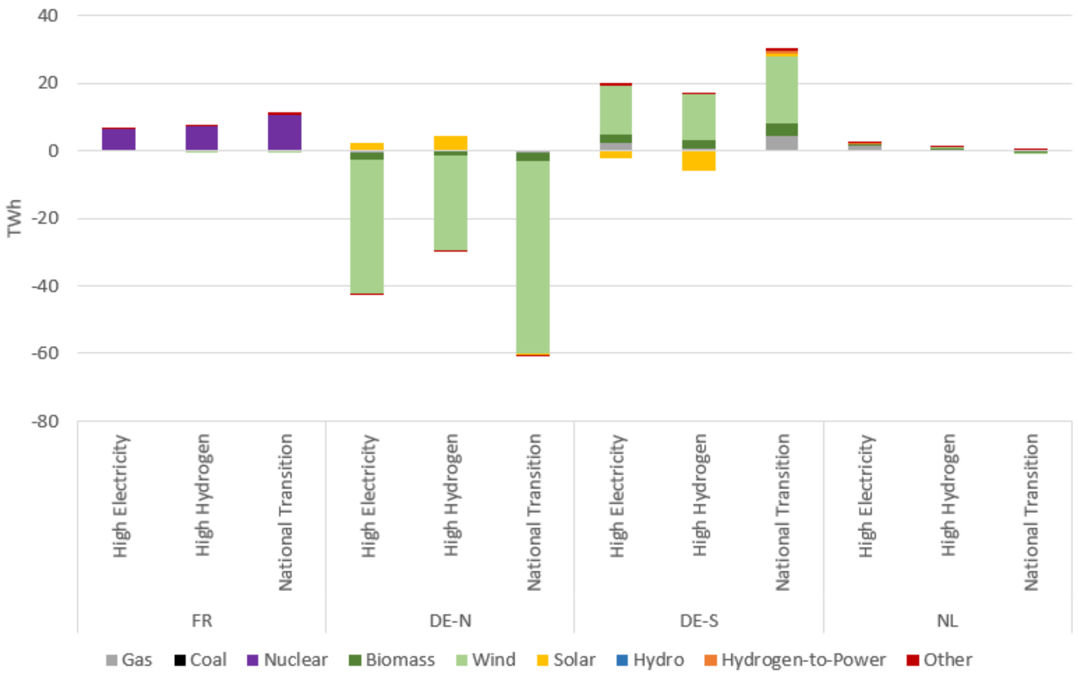


Figure 3.5: Changes in electricity generation in France, German BZs and the Netherlands due to redispatch

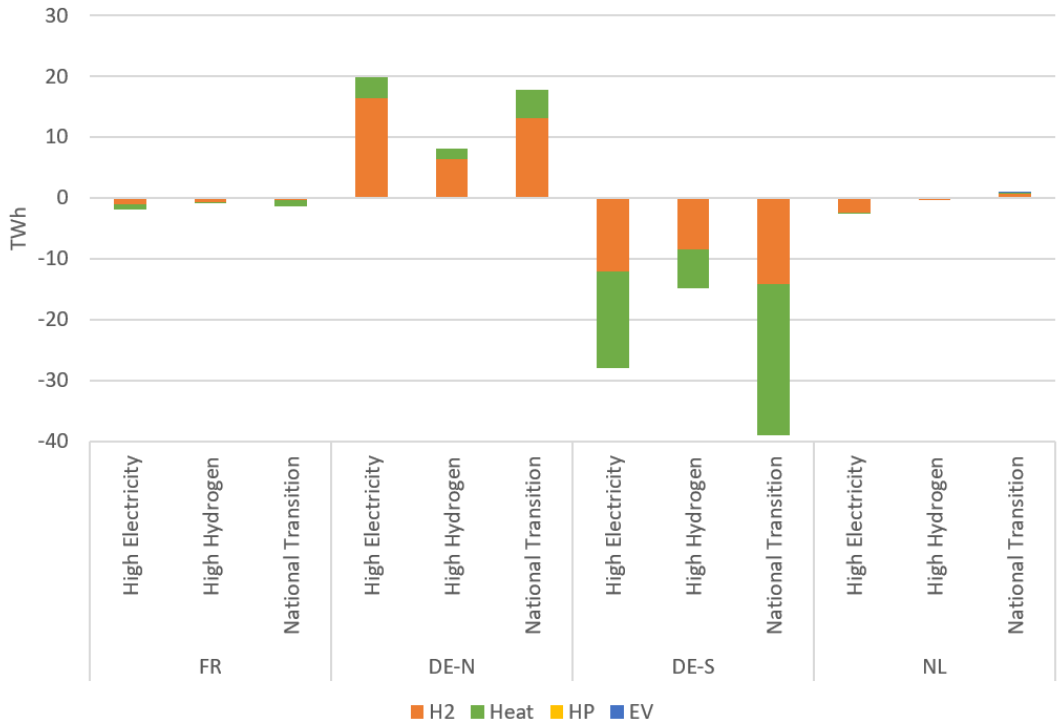


Figure 3.6: Changes in electricity consumption in France, German BZs and the Netherlands due to redispatch

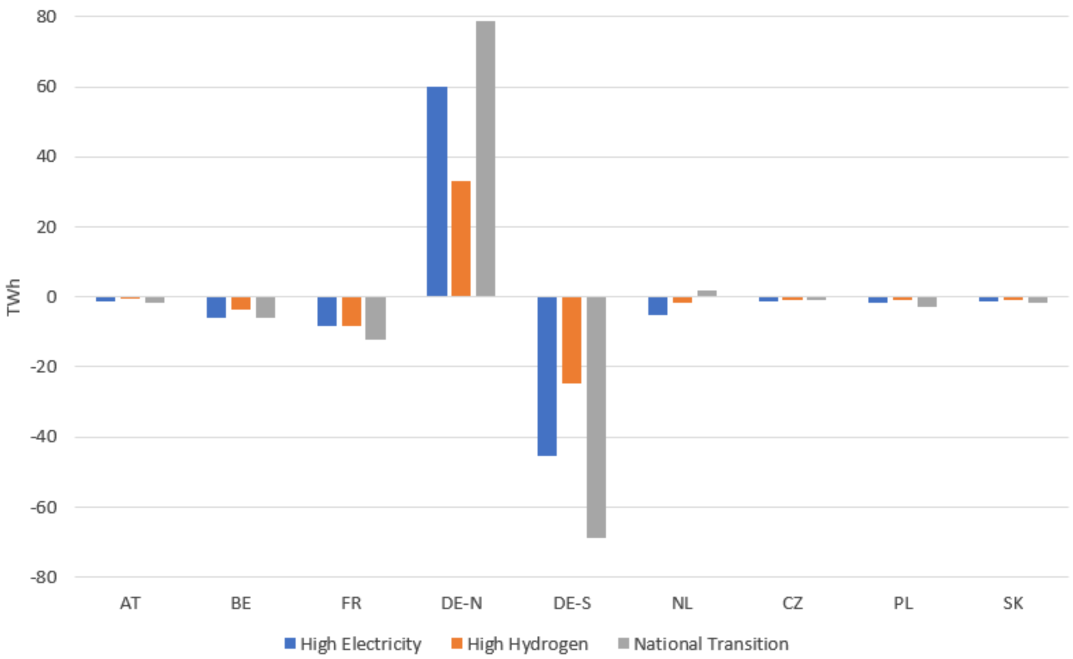


Figure 3.7: Changes in net imports of CORE countries due to redispatch

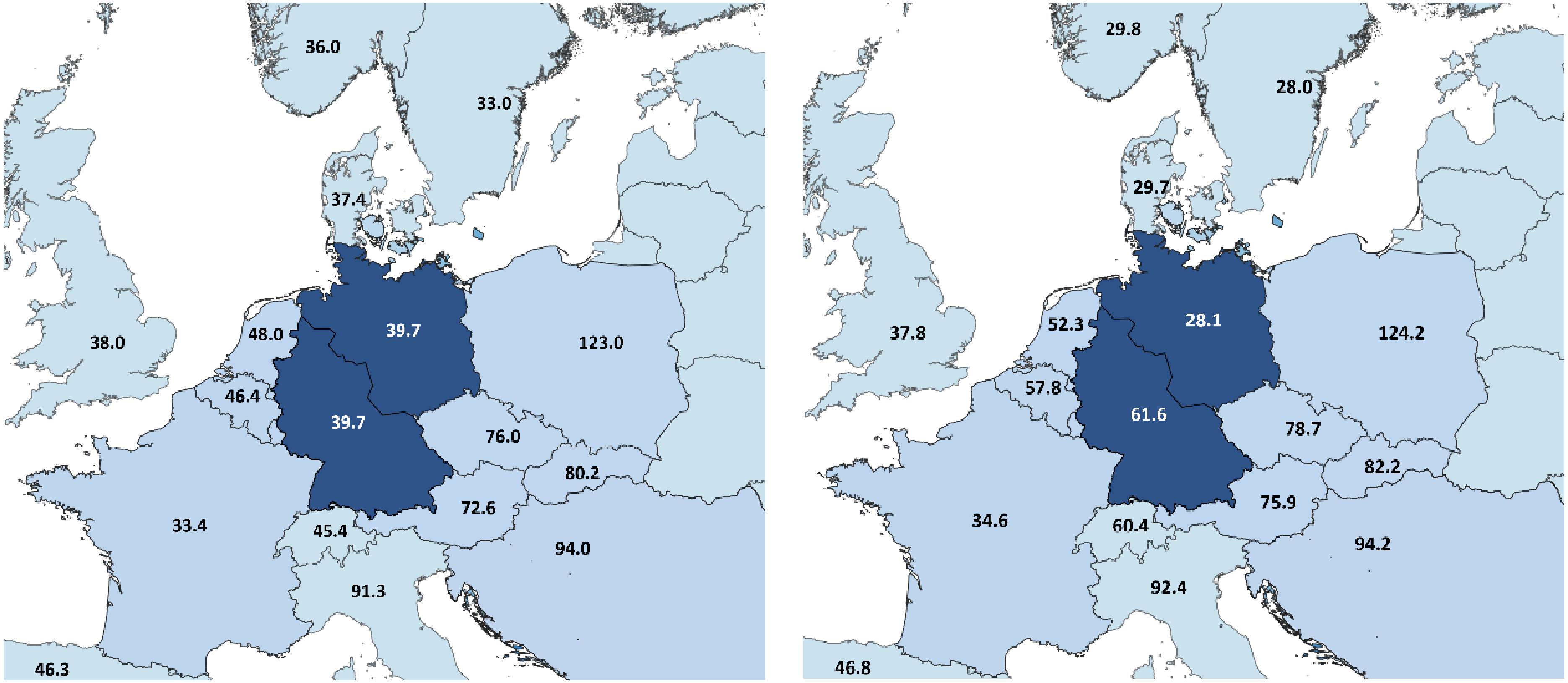


Figure 3.8: Average electricity prices in €/MWh in High Electricity scenario (left: country case, right: base case)

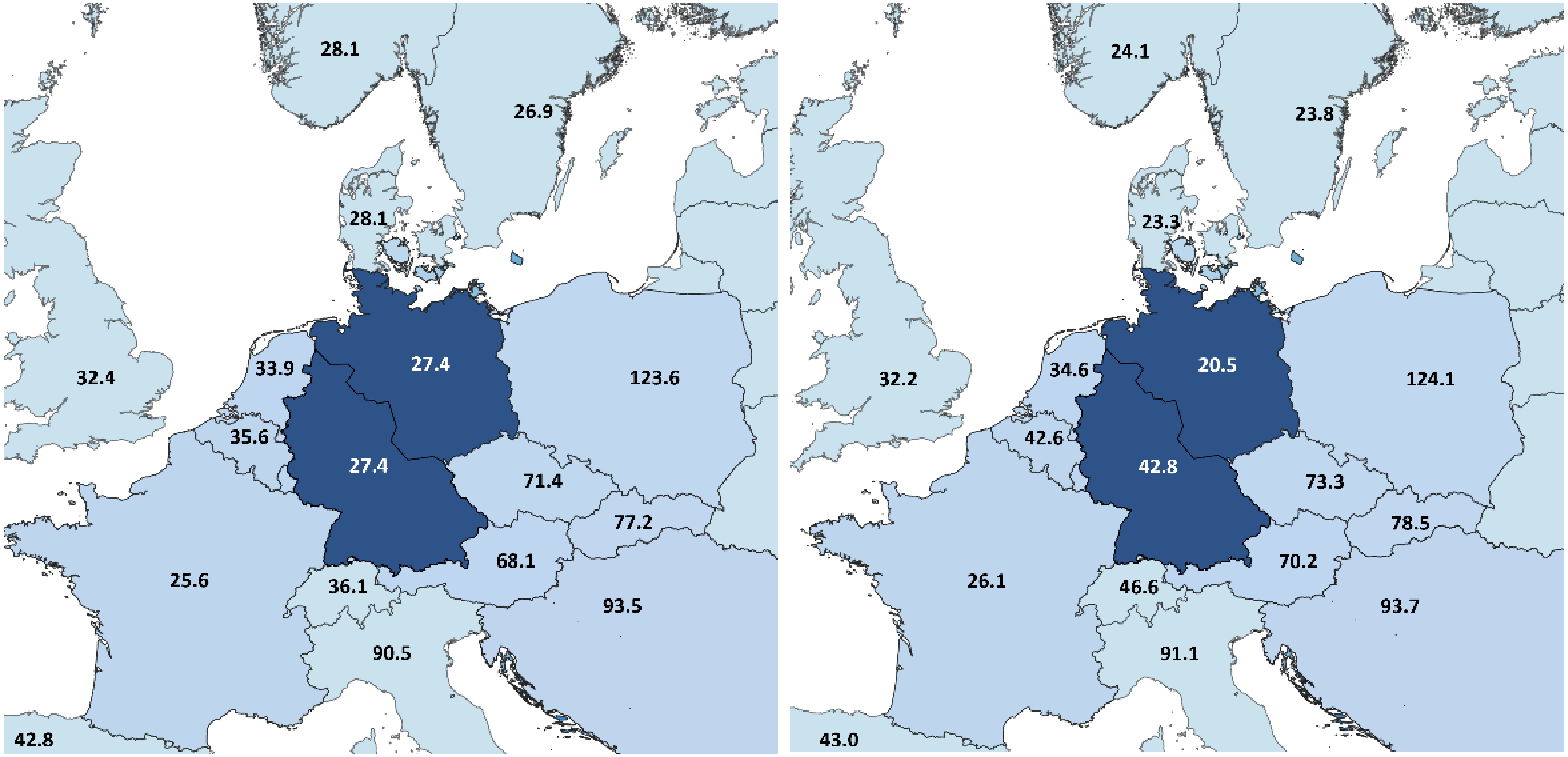


Figure 3.9: Average electricity prices in €/MWh in High Hydrogen scenario (left: country case, right: base case)

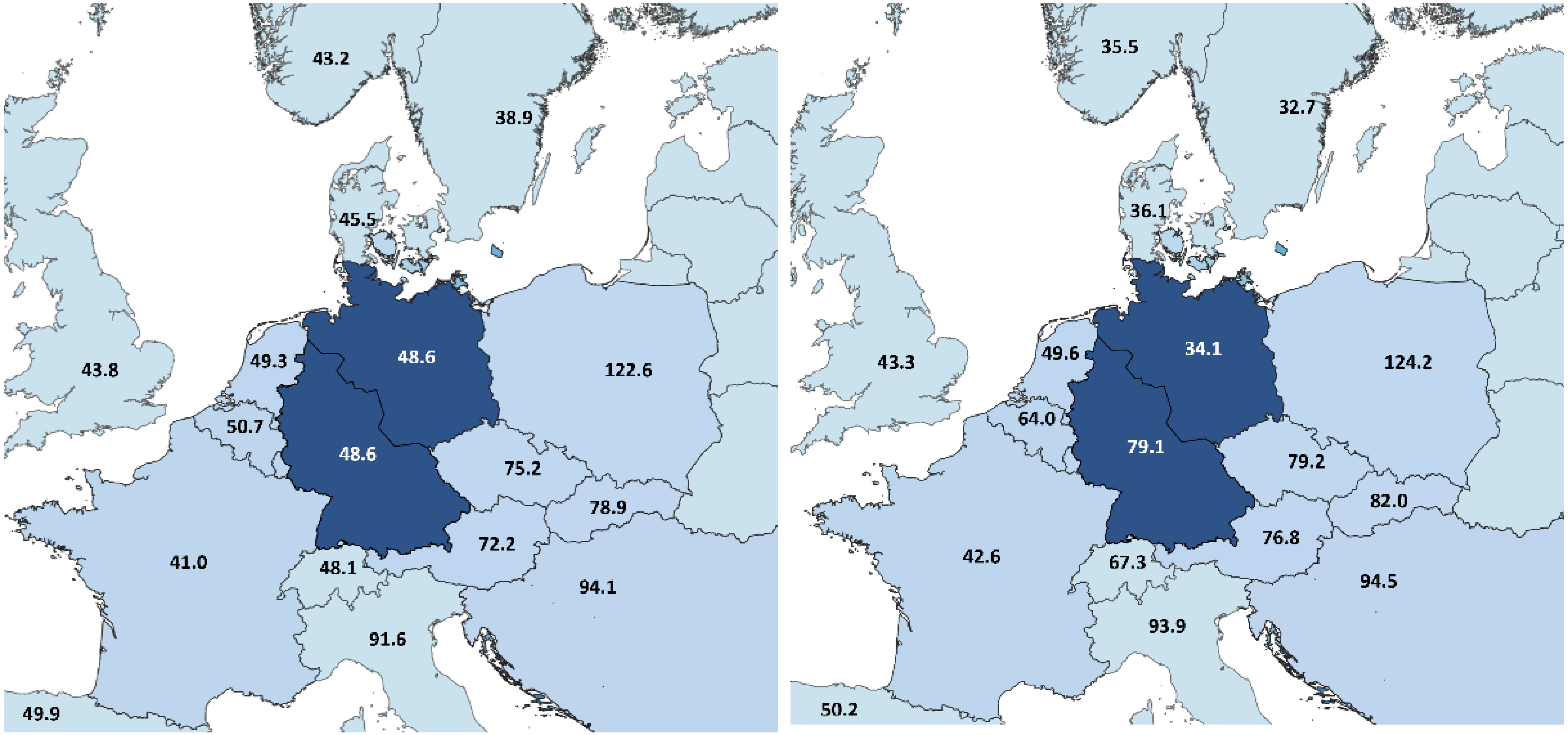


Figure 3.10: Average electricity prices in €/MWh in National Transition scenario (left: country case, right: base case)

3.2 DE4 BZ configuration

Once network constraints between North-West, North-East, West and South Germany are taken into account in market optimization, this results in the following socio-economic welfare effects;

- **Producer surplus** increases with deployment of more expensive generators for redispatch, increasing both generators' profits as well as average implicit electricity prices in most countries. An exception are the Nordic countries, which can export less electricity and therefore exhibit lower implicit electricity prices. The increase of producer surplus is most prevalent in the CORE countries, with the exception of the bidding zones in Northern German (i.e. DE-NW and DE-NE).
- Decrease of **consumer surplus** due to the higher implicit electricity prices in all countries. Usually, consumer surplus moves in opposite direction of the producer surplus effect.
- **Congestion rents** increase in all scenarios for two reasons. First, TSOs earn congestion rents on the additional cross-zonal lines within Germany. Second, the additional network constraints increase the electricity price spreads between countries, notably in the CORE countries.

The effects of redispatch on socio-economic welfare are shown in Figure 3.11-Figure 3.13, and effects on CO_2 emissions in Figure 3.14. Germany and Poland are facing the most significant impacts on CO_2 emissions, with an increase of the former of up to 5 Mton in the National Transition scenario.

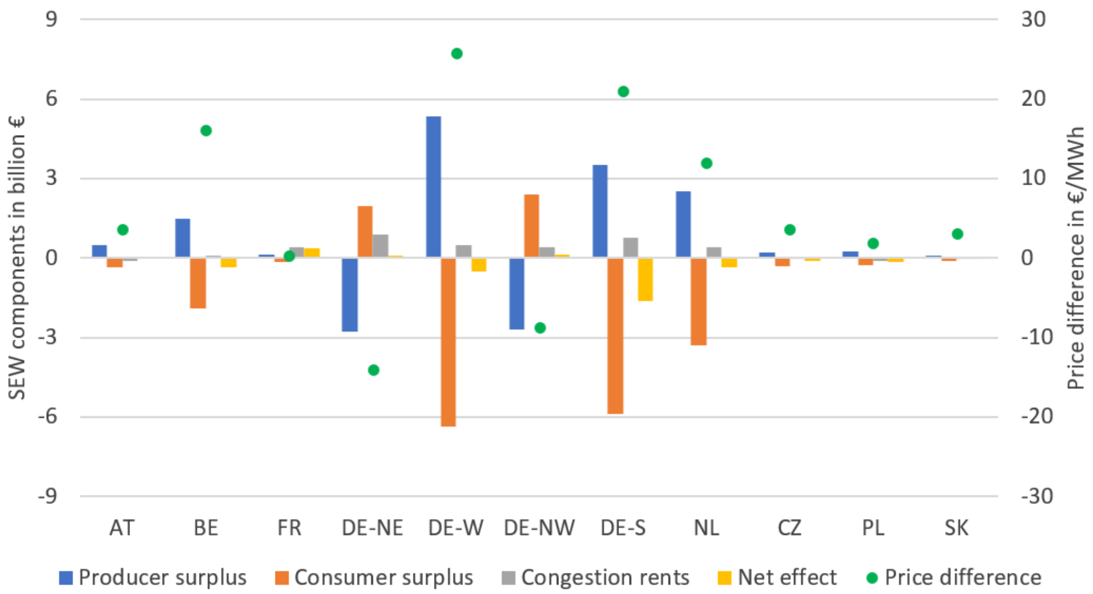


Figure 3.11: Incremental SEW effects due to redispatch for the CORE countries in the High Electricity scenario

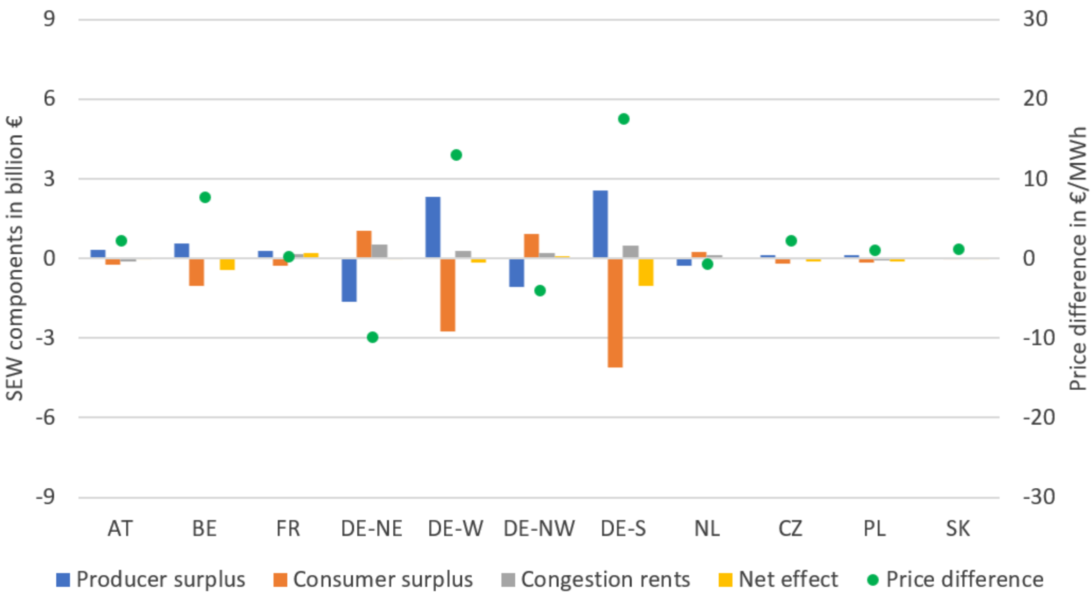


Figure 3.12: Incremental SEW effects due to redispatch for the CORE countries in the High Hydrogen scenario

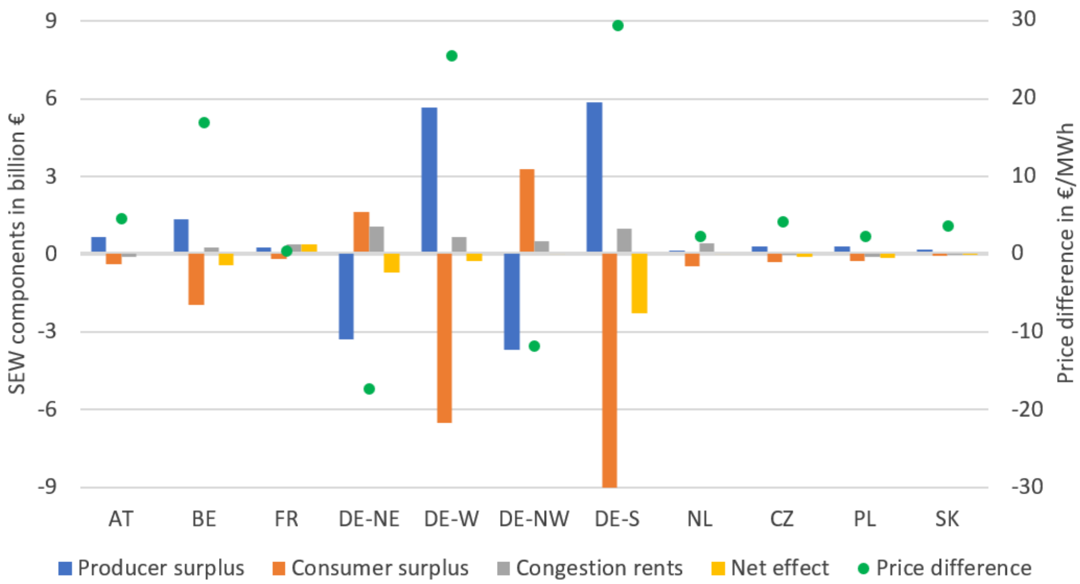


Figure 3.13: Incremental SEW effects due to redispatch for the CORE countries in the National Transition scenario

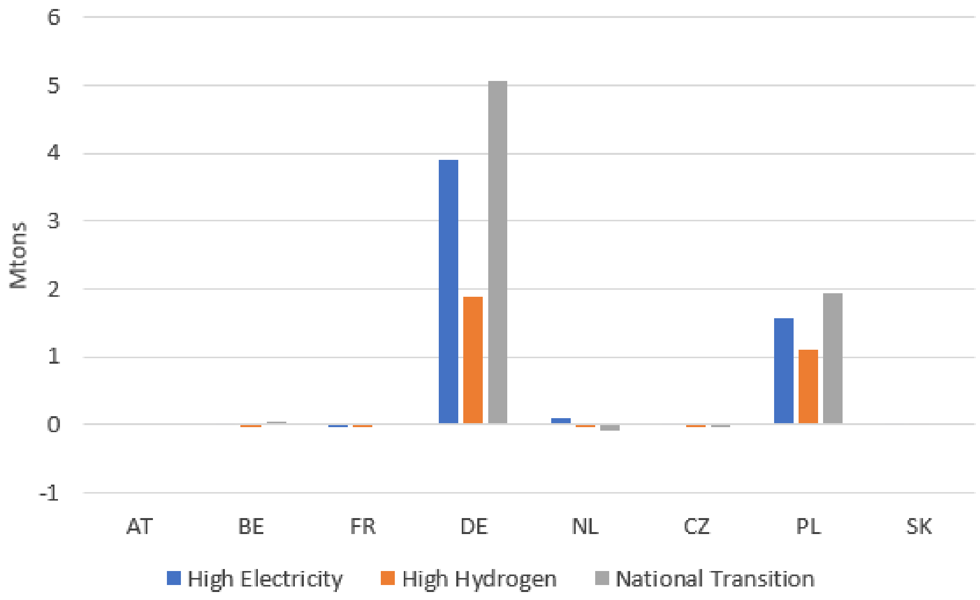


Figure 3.14: Changes in CO_2 emissions of the CORE countries due to redispatch

Reasons for the increase in redispatch costs across scenarios include:

- The generation mix changes once selected network constraints within Germany are accounted for in market optimization (Figure 3.15). Wind energy decreases in Germany's North East (DE-NE) and North West (DE-NW) regions due to significantly more curtailment compared to the situation without considering specific intra-zonal constraints. As a result, production from gas-fired power plants increases in regions in Southern Germany i.e. Germany West (DE-W) and Germany South (DE-S). The generation increase ranges from 5 TWh in the High Hydrogen scenario, to 11 and 16 TWh in the High Electricity and National Transition scenarios respectively. This also changes generation patterns of neighbouring countries; VRE generation in the Netherlands is reduced due to curtailment, while nuclear generation in France increases. Overall generation dispatch costs increase, and with that implicit electricity prices (i.e. wholesale electricity price plus redispatch remuneration). Effects on (implicit) electricity prices are shown in Figure 3.18-Figure 3.20.
- Electricity trade changes for the CORE countries once the redispatch effect is taken into account, as can be observed in Figure 3.17. Trading changes in a similar manner as in DE2 BZ configuration; Northern BZs, such as DE-NW and DE-NE can export less to regions in Southern Germany, whereas the Southern ones see a reduction in their imports. France generators exports more, whereas countries like Poland and Belgium import less. In the case of the Netherlands, the effect differs across scenarios. In High Electricity, the Dutch market relies marginally more on imports, since connections with Northern Germany BZs allow for more trade. In the other scenarios, the Netherlands remains a net exporter, although to a smaller extent.
- Total demand in EU-27+ decreases compared to the country case due to the higher (implicit) electricity prices (Figure 3.16). This is mainly due to the less flexible demand for electrolysis and industrial hybrid boilers, notably in regions in Southern Germany (DE-W and DE-S).

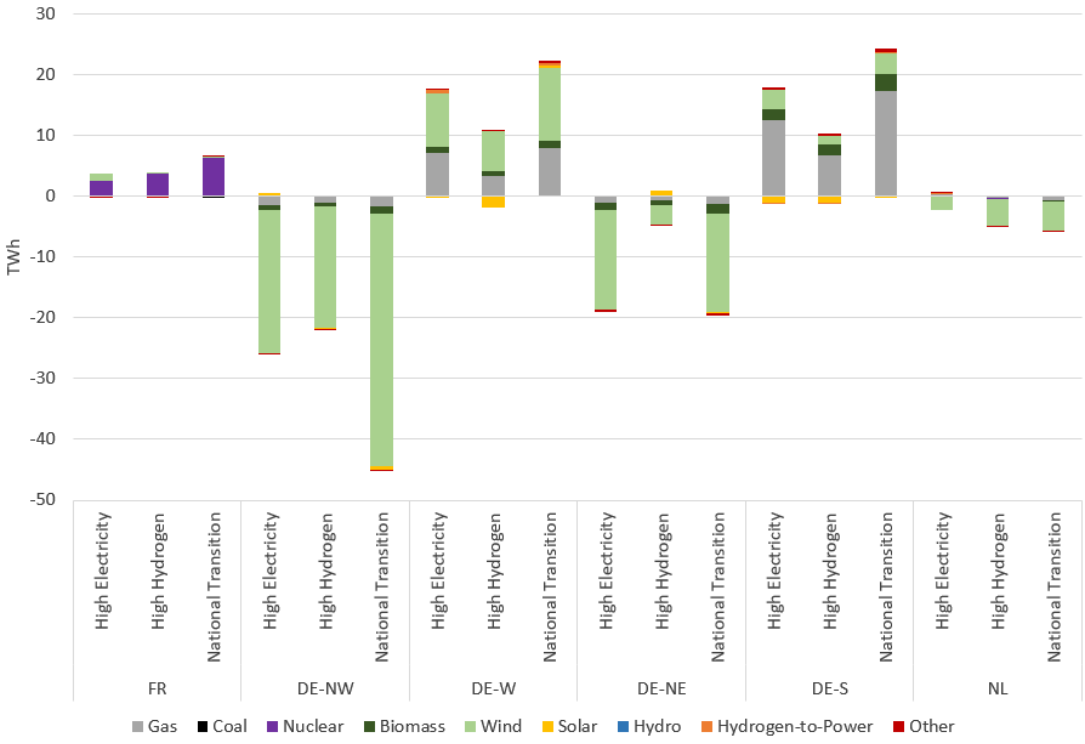


Figure 3.15: Changes in electricity generation in France, German BZs, and the Netherlands due to redispatch

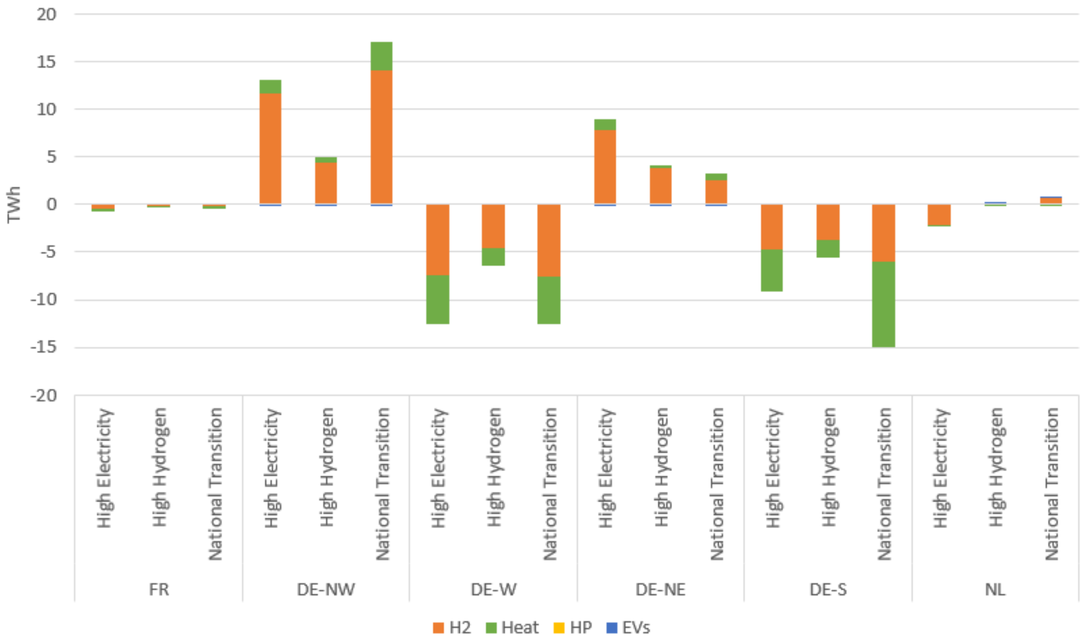


Figure 3.16: Changes in electricity consumption in France, German BZs, and the Netherlands due to redispatch

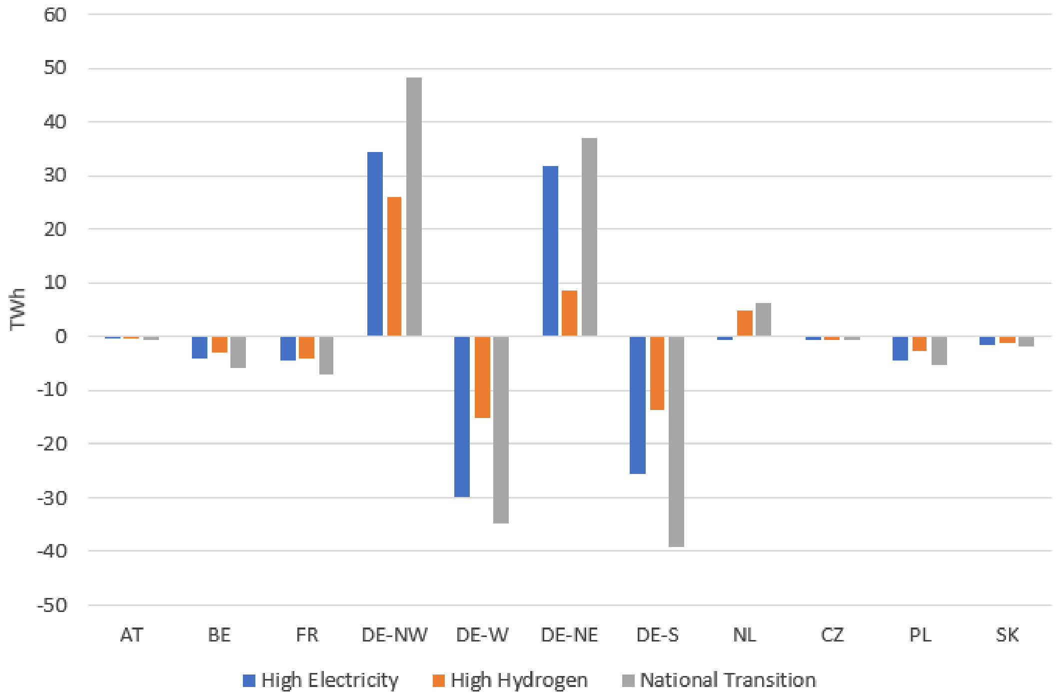


Figure 3.17: Changes in net imports of CORE countries due to redispatch

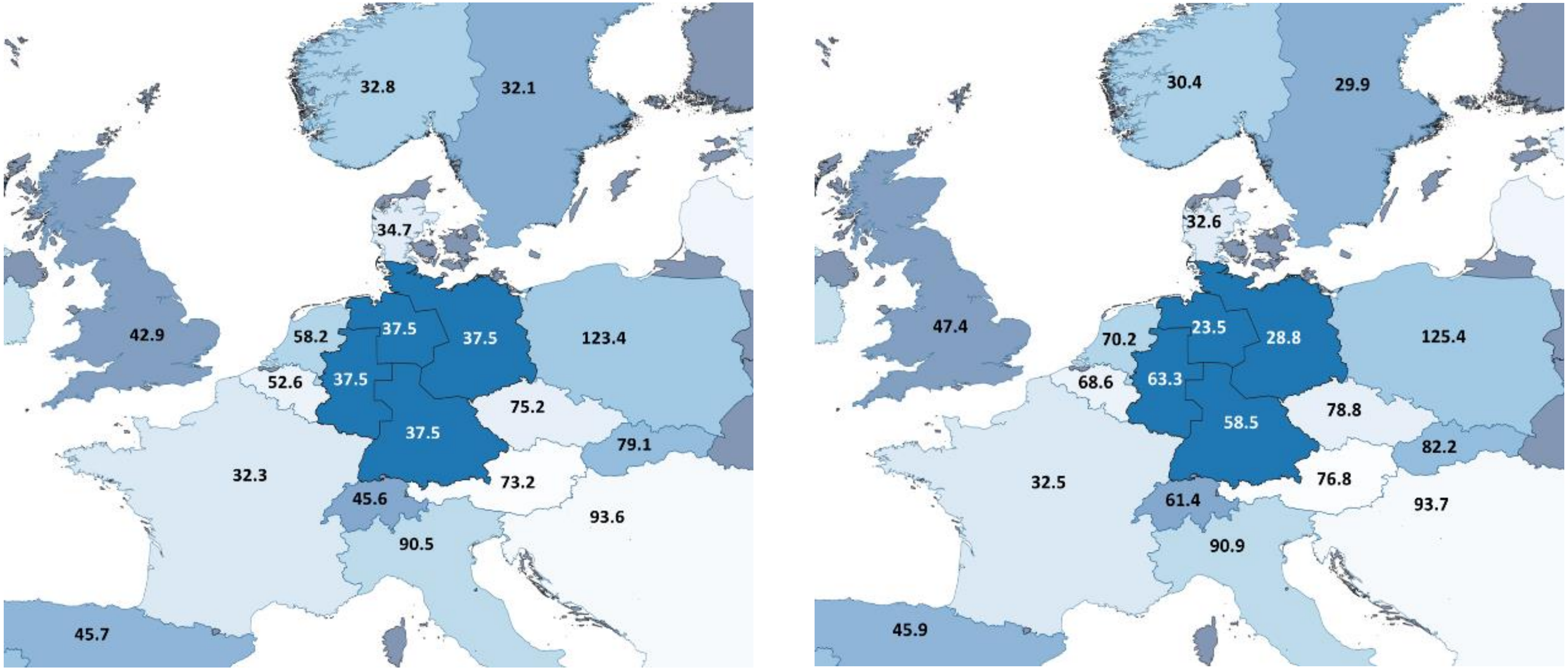


Figure 3.18: Average electricity prices in €/MWh in High Electricity scenario (left: country case, right: base case)

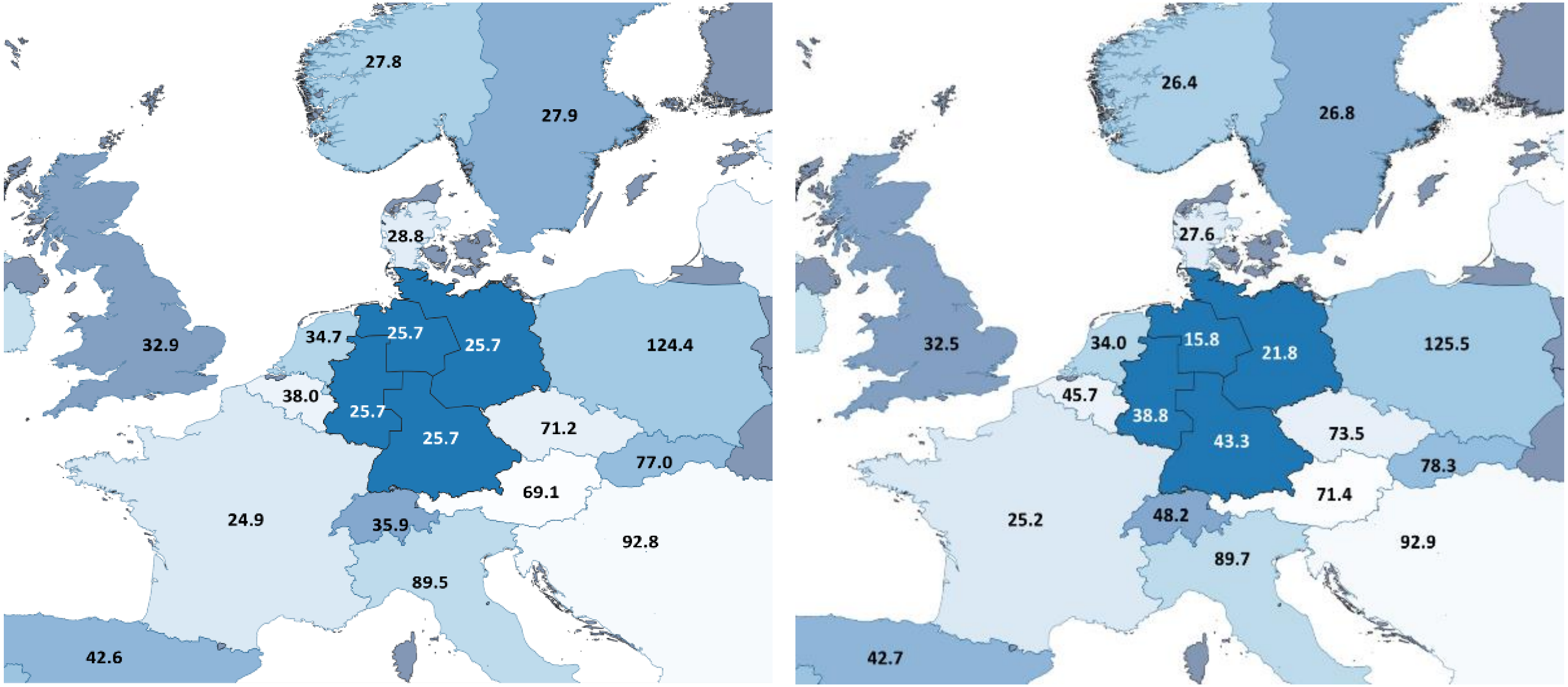


Figure 3.19: Average electricity prices in €/MWh in High Hydrogen scenario (left: country case, right: base case)

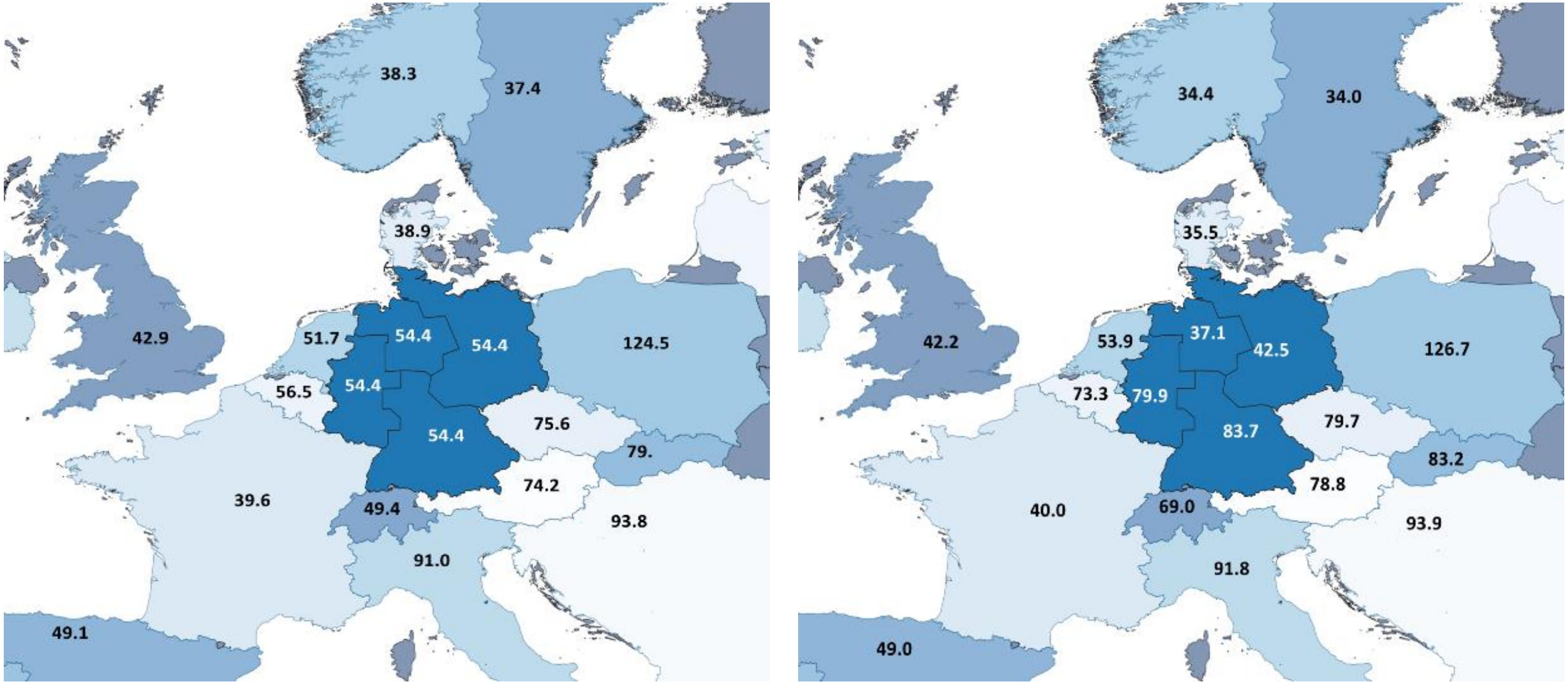


Figure 3.20: Average electricity prices in €/MWh in National Transition scenario (left: country case, right: base case)

3.3 NL2 BZ configuration

Once network constraints between Northern and Southern Netherlands are taken into account in market optimization this results in the following socio-economic welfare effects;

- **Producer surplus** increases in High Hydrogen and National Transition scenarios, but decreases in the High Electricity scenario. For the latter, the effects of redispatch mainly affect the Dutch BZs, Germany and the UK. The decrease in generation in the Netherlands North and Germany reduces implicit electricity prices and producer surplus, and offsets the producer surplus increases in the Netherlands South as well as the UK.
- A decrease of **consumer surplus** is observed in High Hydrogen and National Transition, while consumer surplus increases in High Electricity given lower implicit electricity prices in the Netherlands North and Germany as described above. Interestingly, consumer surplus in Germany increases in the three scenarios, including under the National Transition scenario, with a decrease in flexible demand from Power-to-X due to a marginal increase of the average electricity price. Hence, for this scenario the volume effect outweighs the price effect. Instead, in the other scenarios the increase of consumer surplus is mainly driven by the price effect i.e. lower electricity prices. Effects on (implicit) electricity prices are shown in Figure 3.28-Figure 3.30.
- **Congestion rents** are only affected to a minor extent, given the marginal price spreads due to limited redispatch costs on connections between Netherlands North and South. Again, quantity traded and sold in the wholesale electricity market would remain the same, but implicit wholesale electricity prices change a bit and therefore the congestion rents. They vary across scenarios, with insignificant changes i.e. a net decrease in High Electricity by € 2 million, a net increase in High Hydrogen of € 2 million, and a net zero effect in National Transition.

The SEW results are shown by CORE country and SEW component in Figure 3.21-Figure 3.23 below, and the effects on territorial CO_2 emissions in Figure 3.24.

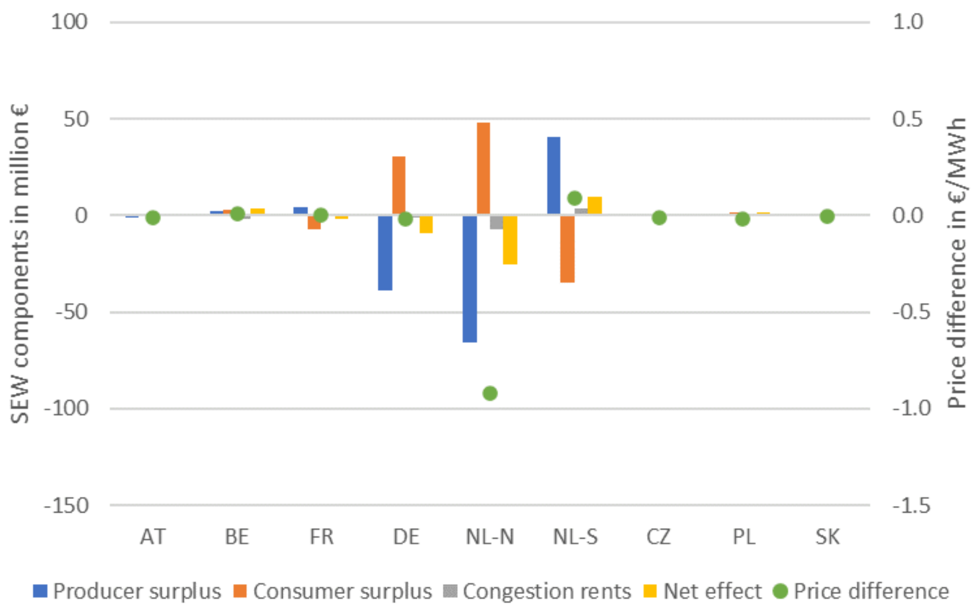


Figure 3.21: Incremental SEW effects due to redispatch for the CORE countries in the High Electricity scenario

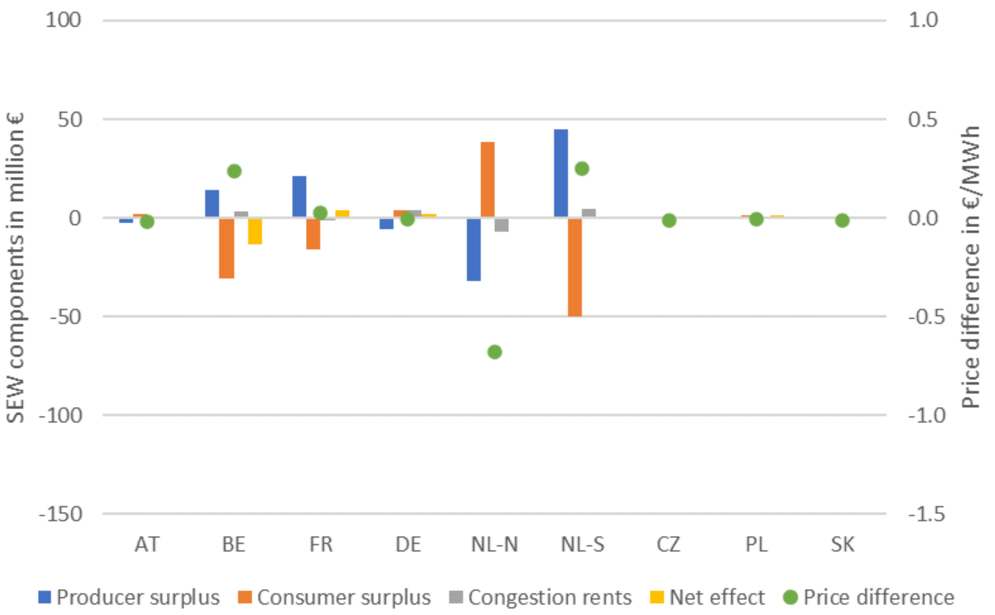


Figure 3.22: Incremental SEW effects due to redispatch for the CORE countries in the High Hydrogen scenario

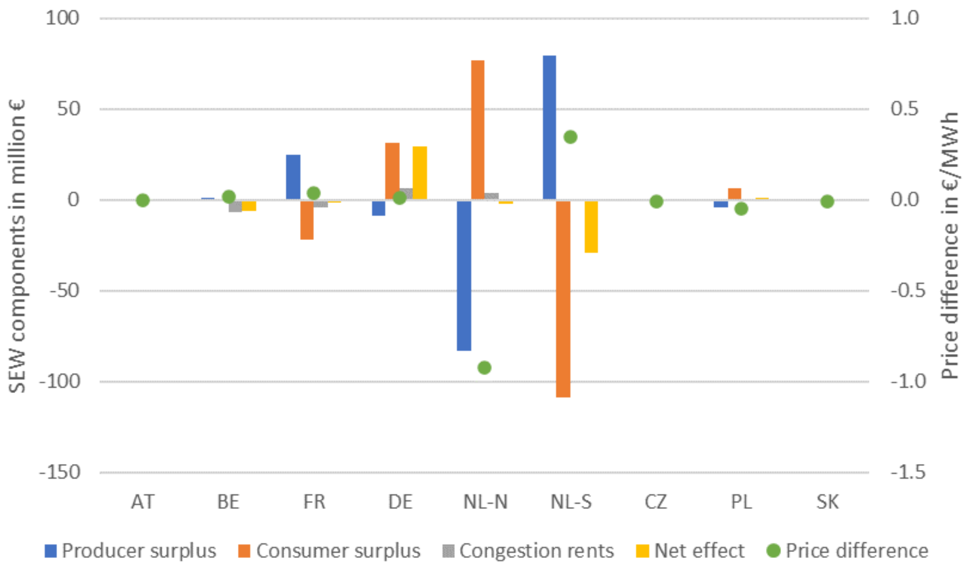


Figure 3.23: Incremental SEW effects due to redispatch for the CORE countries in the National Transition scenario

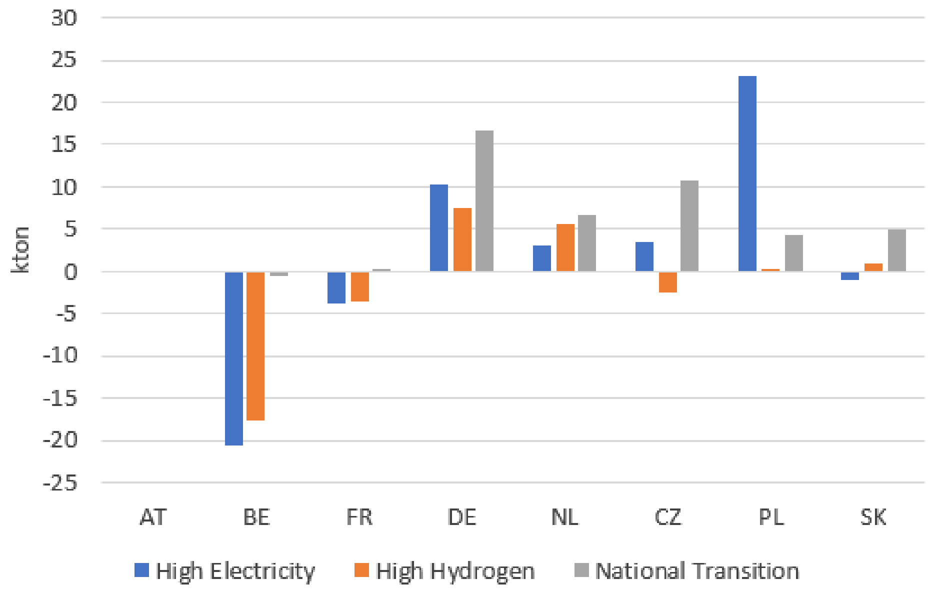


Figure 3.24: Changes in CO_2 emissions of the CORE countries due to redispatch

The redispatch effects of the NL2 configuration are considerably lower than the one observed for the German BZ configurations. This means that the network constraint between North and South Netherlands (NL-N and NL-S) is not as restrictive for the system as the German North-South constraint. The overall increase in redispatch costs and decrease of SEW across scenarios occur for the following reasons:

- The generation mixes of both Dutch areas changes, with very marginal effect in other countries. Following a similar trend as observed in the preceding sections about redispatch in Germany, production in the Netherlands North is reduced, mainly through more curtailment of solar-PV and wind generation. Exports to the Netherlands South diminish, increasing the need for generation in NL-S through lower VRE curtailment. In Germany production is also a bit reduced due to higher VRE curtailment, whereas France sees a marginal increase in production mainly from nuclear generation (see Figure 3.25). The lowest effects on generation are shown for the High Electricity scenario, while the highest effects can be observed for the National Transition scenario. CO_2 emissions change accordingly.
- These changes in generation mix affect imports and exports, mainly in the Dutch areas and in Germany. Given that production in Netherlands North is reduced, it requires higher imports to meet demand. The other way around, once production in the Netherlands South increases, imports are reduced. Germany exports around 1 TWh less due to lower production. The differences in the net trade flows of the CORE countries due to network constraint between NL-N and NL-S is shown in Figure 3.27.
- Total demand in EU-27+ decreases marginally due to different deployment of flexible demand given changes of electricity prices. The overall decline of demand is in the range of 0.04-0.21 TWh for High Hydrogen and National Transition respectively, with High Electricity within this bandwidth. At national level, changes in demand are negligible (Figure 3.26). Netherlands South shows lower deployment from flexible demand, notably from conversion technologies, across the scenarios. For Netherlands-North, this varies across the scenarios. In High Electricity, with tighter system conditions in the Netherlands due to high electricity demand compared to generation, hydrogen production with electrolysis is reduced to allow for load-shedding during critical hours. For Germany, the congestion within the Netherlands reduces its electricity prices and therefore increases flexible demand in the High Electricity and High Hydrogen scenarios. National Transition is

an exception with marginally increasing electricity price, and therefore lower deployment of electrolysis and Power-to-Heat.

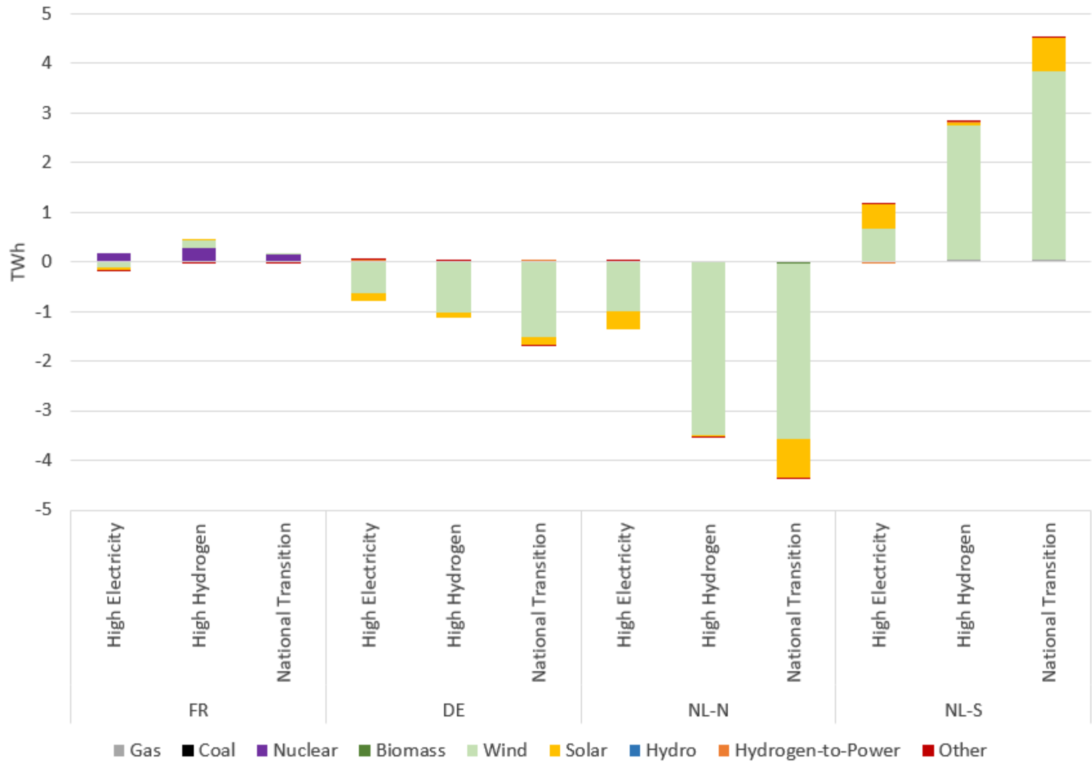


Figure 3.25: Changes in electricity generation in France, Germany, and Dutch BZs due to redispatch

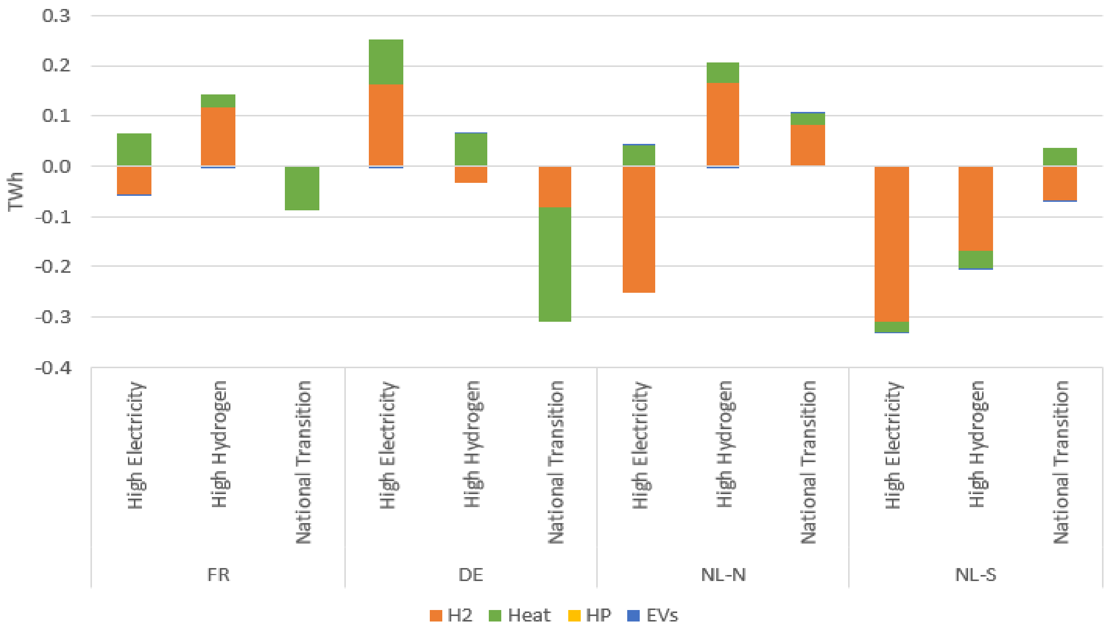


Figure 3.26: Changes in electricity consumption in France, Germany, and Dutch BZs due to redispatch

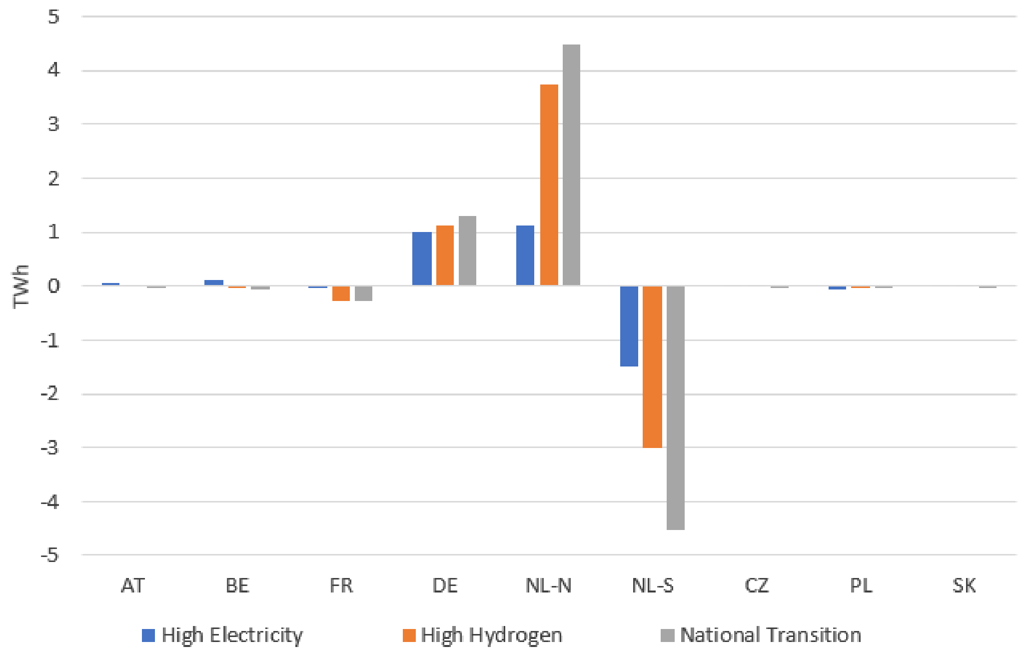


Figure 3.27: Changes in net imports of CORE countries due to redispatch

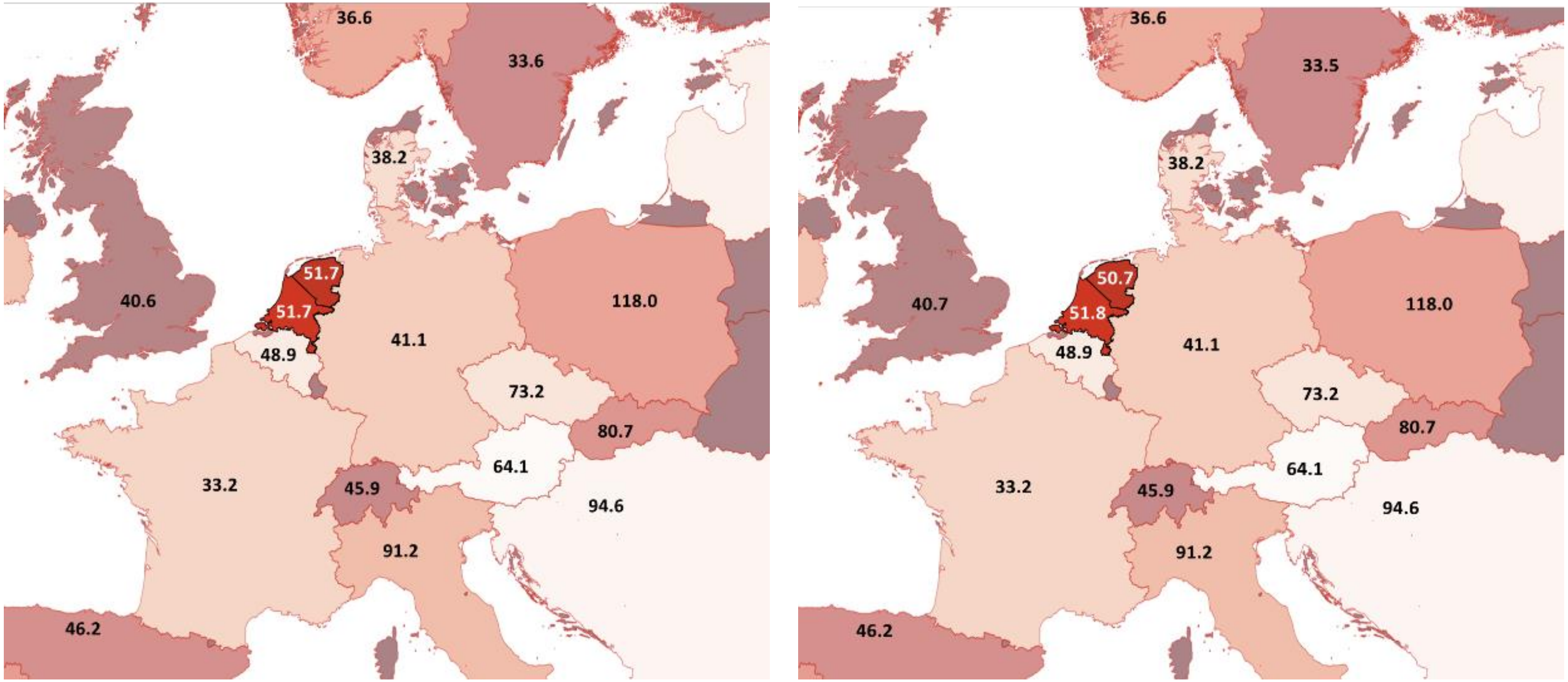


Figure 3.28: Average electricity prices in €/MWh in High Electricity scenario (left: country case, right: base case)

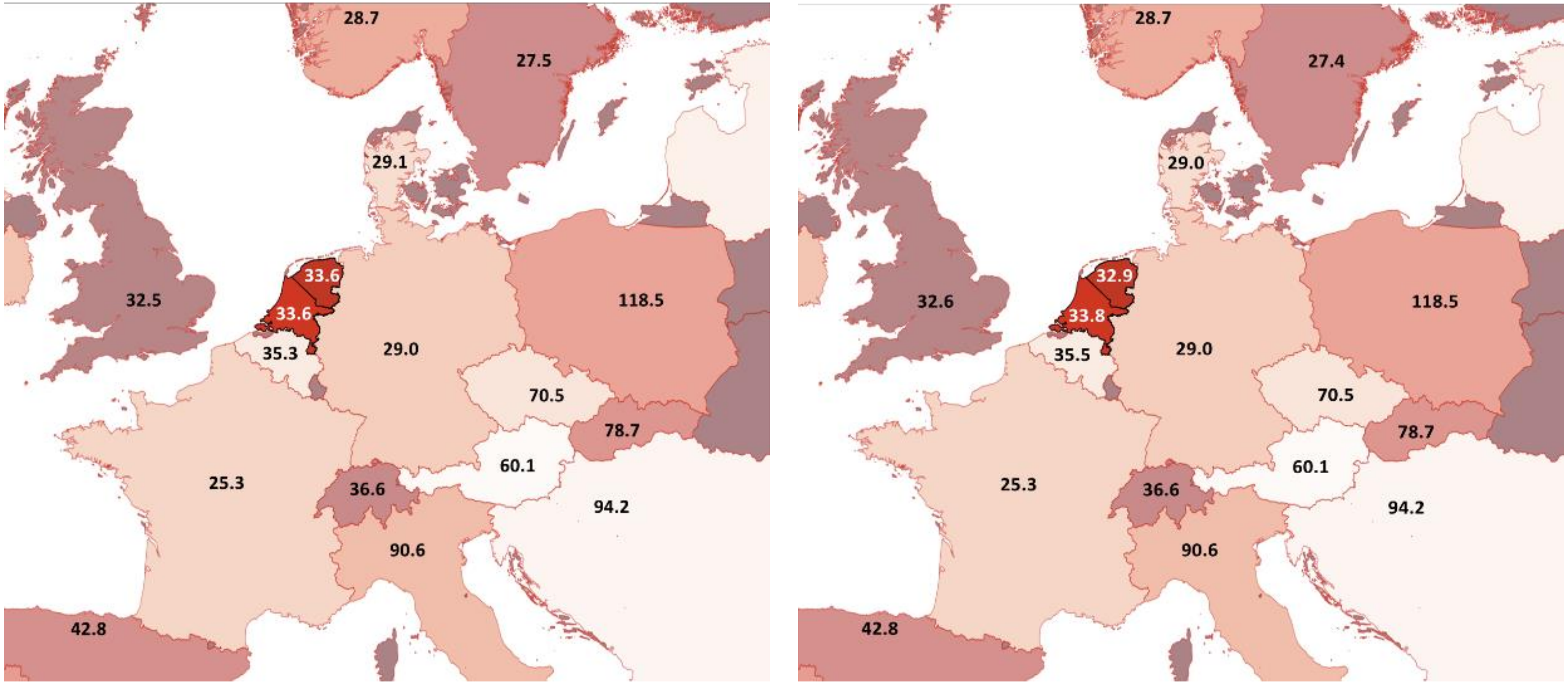


Figure 3.29: Average electricity prices in €/MWh in High Hydrogen scenario (left: country case, right: base case)

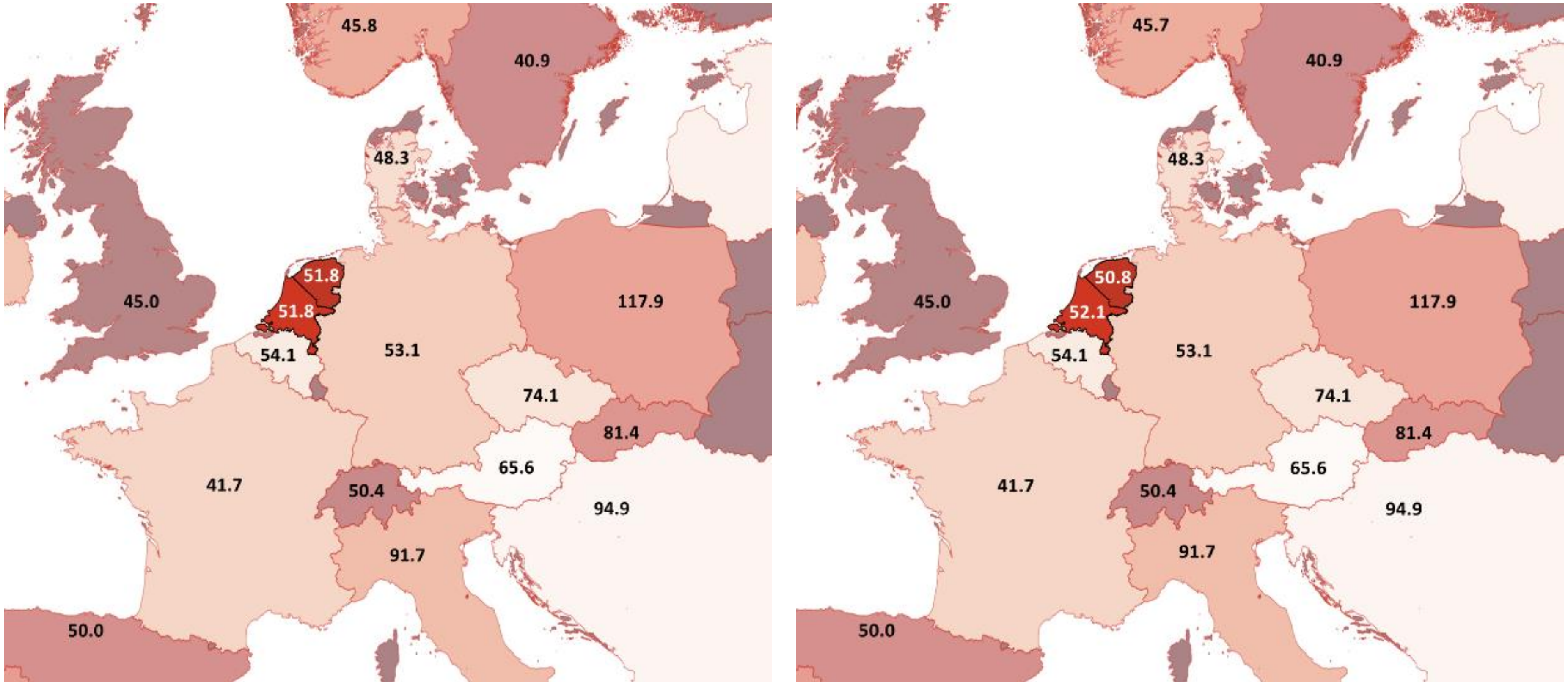


Figure 3.30: Average electricity prices in €/MWh in National Transition scenario (left: country case, right: base case)

4 Effects of bidding zones and their robustness

This Chapter summarizes the effects on socio-economic welfare and CO_2 emissions in the CORE countries in 2035 due to alternative bidding zone configurations in Germany and the Netherlands respectively compared to the base case, which includes redispatch costs. The alternative BZ configurations allow for more available interconnection capacity which in turn enables more electricity trading and lower electricity prices and hence increases social welfare. Note that the effects of inclusion of more network constraints in wholesale electricity prices were already shown in the discussion of the redispatch effects in Chapter 3; the subset of network constraints that necessitate redispatch are the same as those that lead to more bidding zones. From a modelling perspective with a market setup with one wholesale electricity market rather than a two-staged market with separate wholesale and redispatch markets as in practise, and given perfect competition, the reflection of network constraints in either redispatch market or wholesale market does have equal effects on wholesale electricity prices. Hence, the electricity price effects in this Chapter are only due to the effects of more available interconnection capacity and do not relate to (additional) network limitations. The same holds for all other incremental physical and monetary effects that are discussed in this Chapter.

Subsequently, we assess the robustness of the results of each of the BZ configurations against three different decarbonisation scenarios for 2035. If there is a significant net positive welfare effect in three/two/one scenario(s) of the project alternative compared to the base case, we consider the bidding zones as robust, somewhat robust and non-robust, respectively. Given the sensitivity of the market modelling results for assumptions made, results are deemed significant if they are above € 100 million, while results below this amount tend to fall within the error margin. Similarly, CO_2 emission changes are considered as robust once they are significantly reduced under different scenarios.

Likewise, we elaborate upon the robustness of the incremental social welfare effects of bidding zones for different stakeholders i.e. producers, consumers and TSOs respectively. Understanding the distribution effects of new bidding zone configurations over stakeholders and countries is considered as key for its implementation since an uneven distribution of effects is one of the reasons for opposition against new BZ configurations. Therefore the robustness assessment in this case focuses on the robustness of the effects for different stakeholders and CORE countries. If the direction of the incremental effect for each social welfare component is the same for three/two/one scenario(s), we consider the bidding zone as robust, somewhat robust or non-robust, respectively.

The main effects of bidding zones on social welfare and CO_2 emissions are described in Section 4.1. Section 4.2-4.4 discuss the robustness of the DE2, DE4, and NL2 BZ configurations for different decarbonisation pathways as well as the robustness of the distribution effects.

4.1 Main effects of bidding zones

Generally, more opportunities for trading due to alternative BZ configurations increase competition among generators, thus allowing for a more efficient generation dispatch and decreasing electricity prices for the EU-27+. Likewise, from an EU-27+ perspective consumers benefit from access to cheaper electricity generation from abroad. More electricity trading decreases price differences between countries a bit, but generally increases trading volumes and consequently allows for higher congestion rents for TSOs. These congestion rents are either used for recovering redispatch costs, financing of network investments, or directly decreasing grid tariffs for consumers.

The observed effects are a direct outcome of the increase of available cross-zonal network capacity. This increase differs per project alternative and is shown for the CORE countries in Table 4.1. The total increase of available cross-border capacity is derived from the difference in total cross-border capacities between the BZ configurations of the project alternative and the base case ('status quo') respectively. A larger number of zones results in a reduced network with line capacities that produce TTCs that are closer to the original, full network TTCs between bidding zones.[18] More generally, a higher number of bidding zones implies that more transmission bottlenecks are priced allowing for an additional degree of freedom in market optimization (e.g. FBMC), therefore the network can be operated closer to its physical limits. This is confirmed by Laur and Küpper (2020), which state that "better integration of grid constraints increases the overall transmission capacity provided to the market".

Total available interconnection capacity increases by 5.6 GW and 6.7 GW in the DE2 and DE4 BZ configuration respectively, which is about 14-17% of the total available interconnection capacity before the BZ splits. The capacity increases concern mainly interconnections of Germany with neighbouring countries, especially with the Netherlands, Poland, Czech Republic, and Belgium, and to a lower extent with Austria and Slovakia. For the NL2 BZ configuration, total available interconnection capacity increases by 1.1 GW, which is about 3% of the total available interconnection capacity before the BZ split. This concerns mainly interconnections of the Netherlands with Germany, but also of Germany with Czech Republic, Austria, and Poland. The relative increases of available capacity for cross-zonal trade are quite similar to the increases for the German and Dutch BZ configurations reported by ACER (2022). Although ACER applies a rather different method i.e. flow decomposition analysis, they arrive at increases of 11% for DE2, 17% for DE4, and 1% for NL2 BZ configurations respectively.[19] This illustrates that the NR method delivers sensible results.

Note that the NR method delivers equivalent reduced networks that include physical lines between non-adjacent countries, e.g. NL-AT, with limited network capacities. These are so-called synthetic lines. Their inclusion gave rise to counterintuitive results for the NL2 configuration. To improve the comprehensibility of the results, the NR method was rerun without synthetic lines for this specific configuration, at the expense of a small loss of accuracy of the equivalent network compared to the real network. The latter is visible in a decrease of the total cross-border capacities (AC only) of the equivalent network for the base case of the NL2 configuration compared to the capacities of the reduced network for the base cases of the DE2 and DE4 BZ configurations. Moreover, the effects of eliminating synthetic lines on the net position duration curves were tested, showing that although the NR version without synthetic lines allows for somewhat lower exports and imports in most extreme situations compared to the NR version with synthetic lines, overall the shapes of the duration curves are rather similar (see Appendix b). Next, reruns were made with the COMPETES-TNO model showing results that are no longer counterintuitive. However, application of the NR method without synthetic lines for the DE2 and DE4 BZ configurations

[18] Reaching an asymptotic value as approaching a nodal representation.
[19] See paragraphs 92-93 and 104 of ACER (2022). The analysis of ACER focuses on calculating an indicator on the contribution of BZ configurations to maximise cross-zonal capacity. This is operationalized by an analysis of the amount of flows that do not result from capacity allocation, i.e. loop flows and internal flows. Given data limitations, ACER considers only interconnectors as network elements for their analysis of Continental Europe. ACER states that a decrease of loop flows and internal flows 'tends to results in an increase in the capacity available for cross-zonal trade, without the need of applying remedial actions'.

shows a significant loss of accuracy of the NR optimization process, therefore we continue to use the NR results with synthetic lines for these BZ configurations.

Table 4.1: Increase of cross border capacity per alternative BZ configuration

	DE2		DE4		NL2	
	Base case	BZ case	Base case	BZ case	Base case	BZ case
Total AC cross-border capacities [GW][20]	40.4	45.9	40.4	47.1	36.0	37.0
Total increase in cross-border capacity [GW]	5.6		6.7		1.1	

Table 4.2 presents the incremental socio-economic welfare and CO_2 emission effects of the three selected BZ configurations compared to the base case for EU-27+ in year 2035. As can be observed, the alternative German BZ configurations show a significant positive yearly SEW effect, while the yearly CO_2 emissions of the power system decrease. The DE4 BZ configuration presents the highest benefit for the two indicators compared to the project alternative with only two BZs. This is logical, as a higher number of bidding zones implies that more transmission bottlenecks are priced allowing for an additional degree of freedom in market optimization, which allows to operate the network closer to its physical limits. This results in more efficient congestion management and more efficient generation dispatch in each of the project alternatives compared to the base case. In contrast with the German BZ configurations, the social welfare gains of the NL2 BZ configuration are limited. Apparently, the structural congestion on North-South lines in the Netherlands is rather limited compared to the structural congestion on Germany's North-South connections, which could relate to smaller power flows, smaller distances to be bridged, and the smaller bidding zone size of the former. As mentioned previously, we do not account for the possible negative effects of bidding zones including implementation costs ('transition costs') of an additional BZ for TSOs and market participants in these social welfare figures.

Table 4.2: EU-27+ incremental SEW and CO_2 emission effects of selected BZ configurations for three scenarios compared to the base case for year 2035

Project alternative	High Electricity		High Hydrogen		National Transition	
	Δ SEW (M€)	Δ CO_2 (Mton)	Δ SEW (M€)	Δ CO_2 (Mton)	Δ SEW (M€)	Δ CO_2 (Mton)
DE2	2133	-3.8	2274	-3.7	2535	-3.6
DE4	3986	-6.7	4233	-6.0	4581	-7.4
NL2	243	-0.4	310	-0.5	253	-0.4

4.2 Robustness of DE2 BZ configuration

4.2.1 Socio-economic welfare

The DE2 BZ configuration shows positive net social welfare effects in all scenarios ranging from € 2133 million in High Electricity scenario, € 2274 million in the High Hydrogen scenario to € 2535 million in the National Transition scenario for EU-27+ in 2035. See Table 4.2 for an

[20] These rounded figures consider only the cross-border capacities and not the intrazonal capacities of the alternative BZ configurations.

overview. Hence, this BZ configuration is generally considered as robust for the three scenarios.

SEW components
Figure 4.1 shows the decomposition of the total or net incremental effect per scenario in the different SEW components i.e. producer surplus, consumer surplus, and congestion rents. In the High Hydrogen and National Transition scenarios, producer surplus of the DE2 BZ configuration decreases significantly compared to the base case. More bidding zones induce higher available interconnection capacity and with that more electricity exchanges among countries, as well as generally somewhat lower wholesale electricity prices.

Generally, net benefits for producers decrease since both the volume effect of more available interconnection capacity as well as the price effect due to increasing competition among generators tend to decrease the producer surplus. In the National Transition scenario, the overall producer surplus decrease is larger than in the other scenarios, due to significantly lower electricity prices in Germany South and Switzerland as well as decreasing exports from France to Germany South due to less nuclear generation. This can be explained by the constrained situation in Germany South in the base case, which is greatly mitigated by increased opportunities for exchange with neighbouring countries in the project alternative. In the High Electricity and High Hydrogen scenarios, the lower producer surplus in Germany South, Poland, Austria, and Czech Republic, is at least partially compensated by significantly higher producer surplus in Germany North and the Nordic countries. In the High Electricity scenario, this means that the increase of producer surplus in the latter countries outweighs the decrease of producer surplus in other CORE countries, resulting in a net producer surplus of € 100 million.

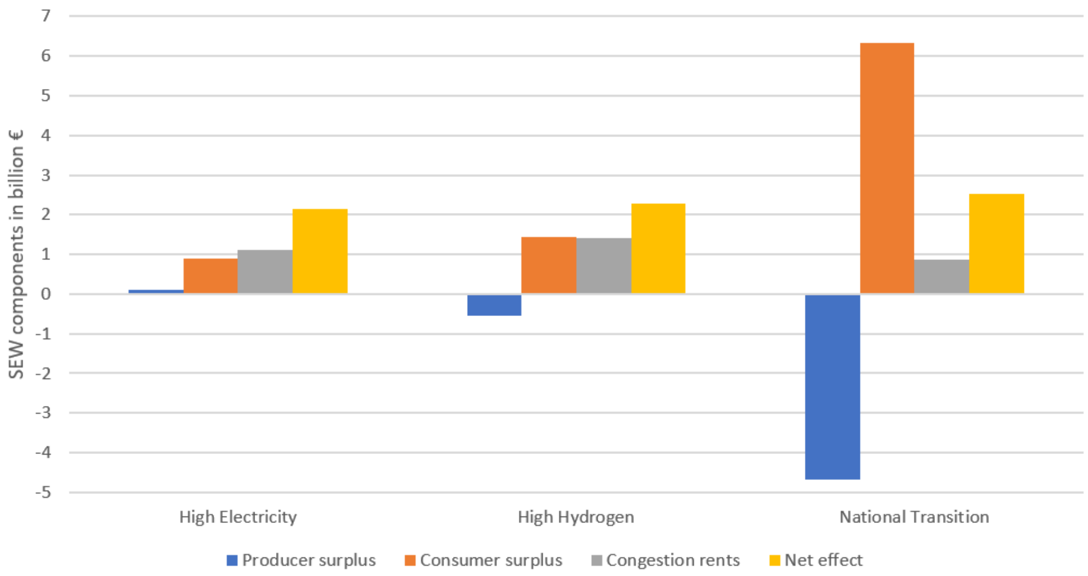


Figure 4.1: Incremental socio-economic welfare effects of the DE2 BZ configuration in EU-27+ in 2035

Consumers benefit from increases of consumer surplus due to lower electricity prices, notably in bidding zones located at the Southern side of the German North-South BZ border but also in Poland. The price effect is exacerbated by the volume effect of increasing electricity consumption of flexible demand. Again, the net change of surplus is larger in the National Transition than in the High Electricity and High Hydrogen scenarios. This is mainly caused by the significantly larger price effect in National Transition compared to other scenarios, notably lower prices in Germany South which increase its consumer surplus by about € 4.6 billion compared to about € 700 and € 950 million in High Electricity and High Hydrogen scenarios, respectively. At the same time, decreases of producer surplus and increases of consumer surplus cancel out each other more in National Transition than in the other scenarios. Given that the deployment of flexible demand is about 150 TWh higher in High Electricity than in National Transition, the price effect clearly outweighs the volume effect for the latter.

TSOs earn more congestion rents in nearly all CORE countries mainly due to smaller price differences between countries as well as somewhat more electricity trading. This lowers ceteris paribus the electricity network tariffs for consumers in most countries. The largest positive effects on congestion rents are visible in Germany North, Germany South, Poland, and Czech Republic. France is an exception, especially in the National Transition scenario due to significantly smaller price differences with Germany South and Switzerland. The High Hydrogen scenario shows the highest overall increase. This results from the increase of electricity trading with neighboring countries which is highest in High Hydrogen, followed by High Electricity and National Transition.

The net social welfare effect as well as its distribution over stakeholders and CORE countries is shown for each of the three scenarios in Figure 4.2, Figure 4.3, and Figure 4.4 respectively. Overall, these figures show that the size of SEW effects is much larger in the National Transition scenario due to the constrained situation in Germany South in the base case compared to the other scenarios. SEW effects are lowest in the High Electricity scenario as changes in producer and consumer surplus largely cancel out each other. The direction of SEW effects is largely consistent in all scenarios, except for the rather insignificant increase of producer surplus in the High Electricity scenario. Hence, the SEW distribution over stakeholders and countries can be considered as largely robust.

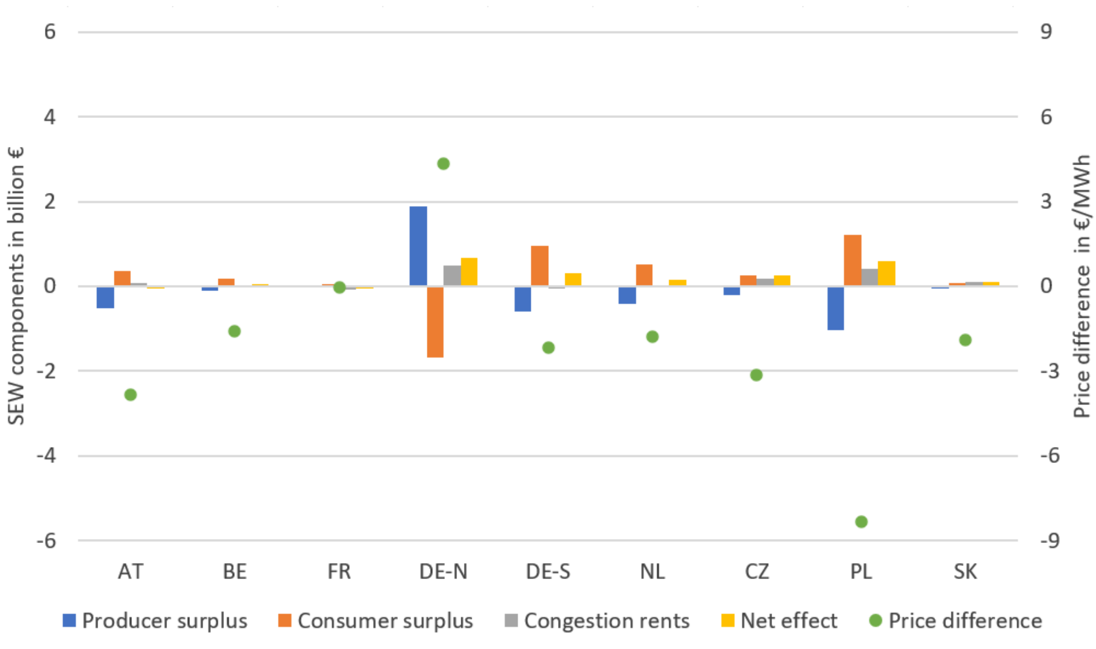


Figure 4.2: Incremental SEW effects of bidding zones for the CORE countries in the High Electricity scenario

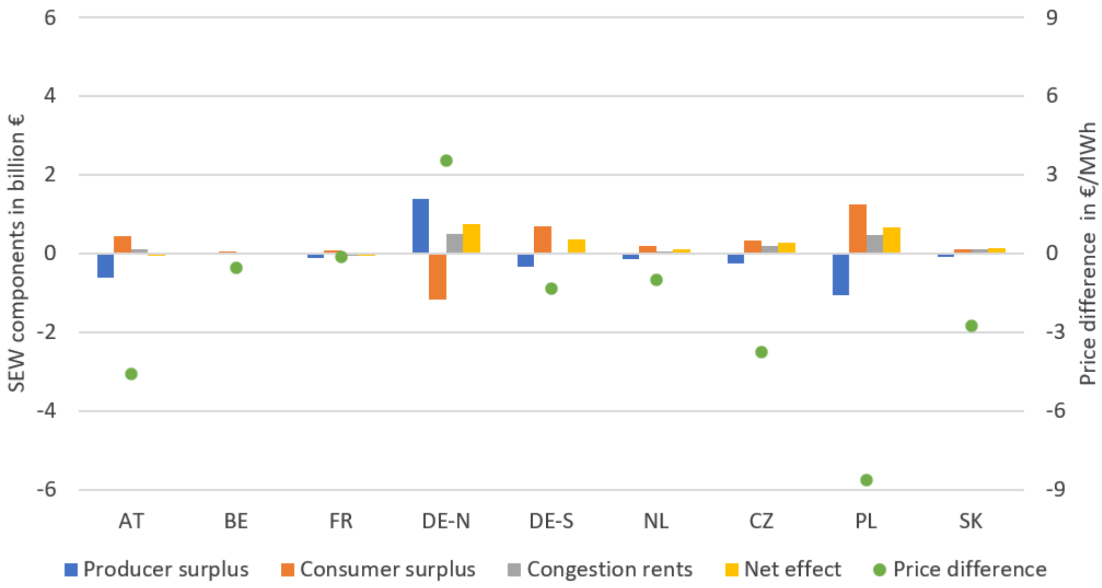


Figure 4.3: Incremental SEW effects of bidding zones for the CORE countries in the High Hydrogen scenario

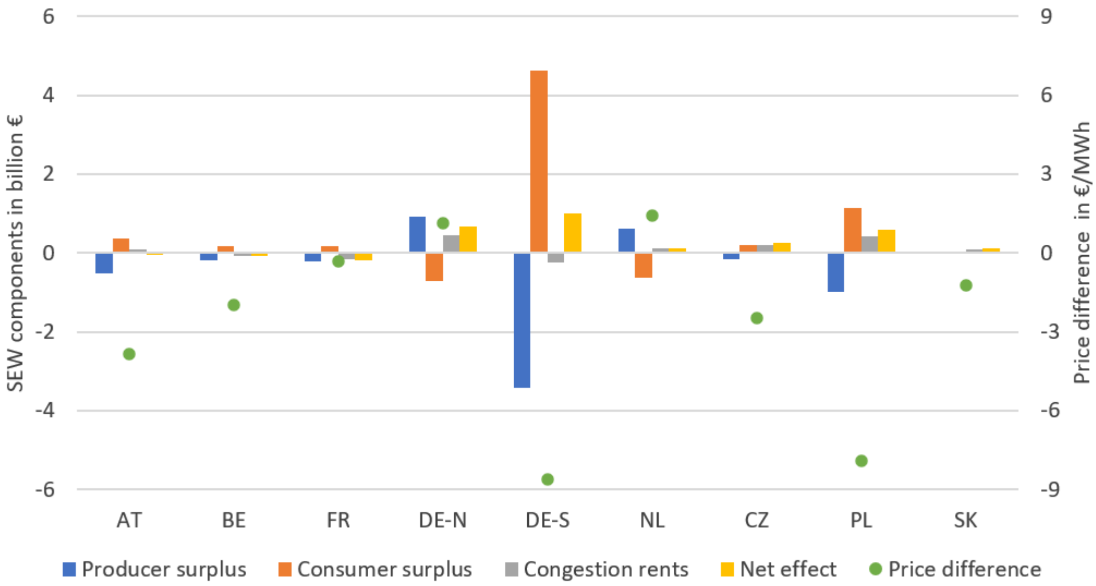


Figure 4.4: Incremental SEW effects of bidding zones for the CORE countries in the National Transition scenario

Drivers for highest and lowest social welfare effects

The differences in social welfare effects between on the one hand the National Transition scenario and on the other hand the High Electricity scenario should be seen in conjunction with the following underlying developments related to generation mix, demand levels and flexible demand deployment, net imports and exports, and electricity prices.

Generation mix

The increase of available cross-zonal capacity with the alternative BZ configuration allows for a more efficient generation dispatch. The effects of the BZ compared to the base case in the generation mix are shown in Figure 4.5. Key points include:

- Wind production in Germany North (DE-N) increases in the three scenarios, with around 20 TWh of additional offshore wind generation due to less curtailment. Hence, the higher cross-zonal network capacities allow to accommodate more wind production in the power system. A similar effect can be observed in Germany South (DE-S), together with a decrease in the need for generation from dispatchable generation such as natural gas and biomass.

- Because of the increase of generation in Germany, the generation of both France and the Netherlands change in opposite direction compared to the base case. Germany South replaces nuclear generation from France by cheaper generation from other countries while Germany North is able to export more electricity from wind generation to the Netherlands, amongst others.

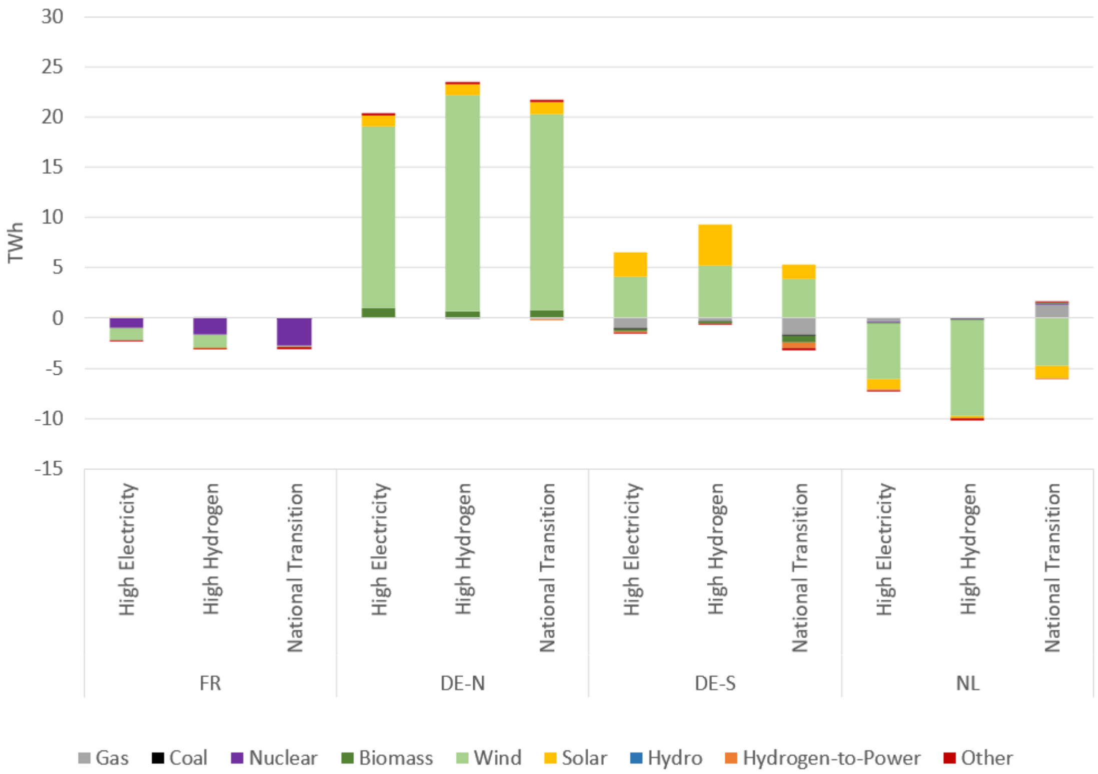


Figure 4.5: Changes in electricity generation in France, German BZs and the Netherlands due to DE2 BZ configuration[21]

Demand level and flexible demand deployment
Flexible demand of Power-to-X technologies is affected by changes in electricity prices in the project alternative compared to the base case. As shown in Figure 4.6, in Germany North flexible demand, mainly from electrolysis, decreases due to higher electricity prices while in Germany South Power-to-Heat increases due to lower electricity prices compared to the base case. As explained in more detail in Appendix A, Germany North disposes of the largest share of electrolysis capacity installed, whereas industrial demand, notably Power-to-Heat, is more prominent in Germany South.

Effects are largely the same in the three scenarios analysed, with National Transition showing a net increase of Power-to-X deployment of around 4 TWh more than in the other scenarios.

[21] Effects on other CORE countries are insignificant and therefore not shown.

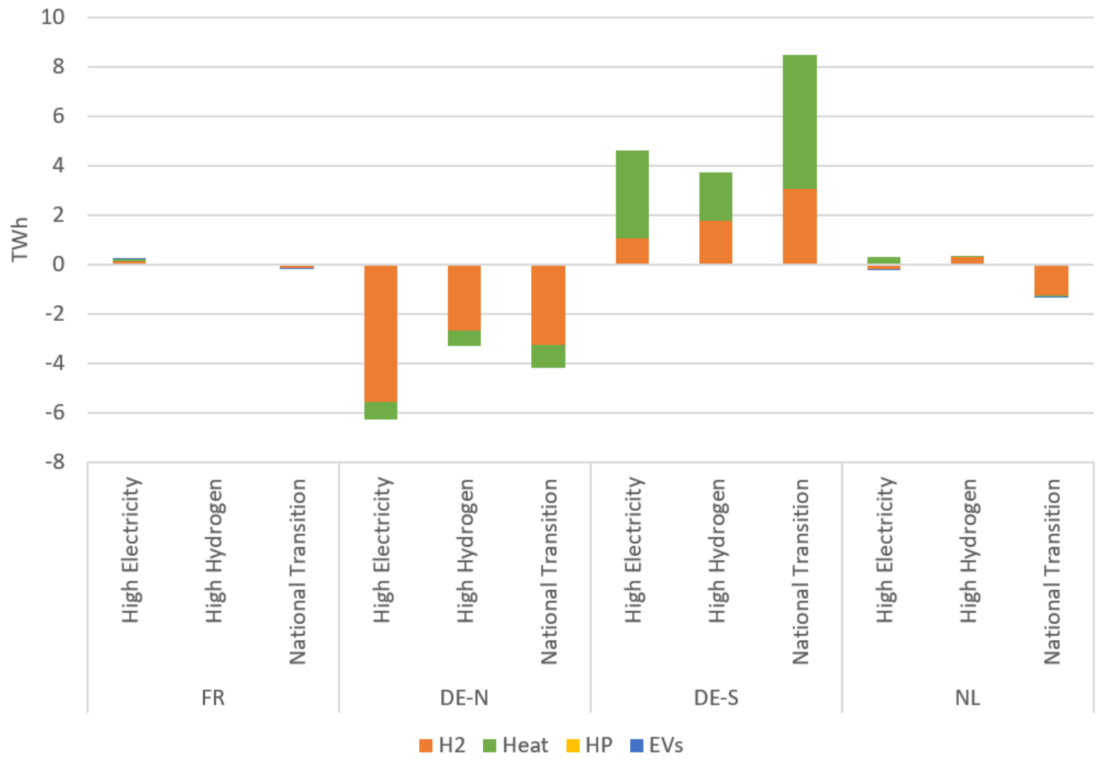


Figure 4.6: Changes in electricity consumption in France, German BZs, and the Netherlands due to DE2 BZ configuration[22]

Net imports and exports
As a result of changes in generation and demand, net imports differ as well (see Figure 4.7). Germany-North exports about 25 TWh more, given increasing electricity production and decreasing consumption. In Germany South, the additional production matches with the increase of flexible demand, except for the National Transition scenario where additional demand exceeds additional supply. Hence, net imports of Germany-South increase a bit in the latter scenario. In the Netherlands, generation decreases while demand remains almost equal, hence net imports increase to the same extent as generation decreases. Net imports of France increase slightly due to marginally lower production.

Overall, differences across scenarios are rather small. The exception are the net imports in the National Transition scenario compared to the other scenarios for Germany and the Netherlands. Note that the national German scenario assumes direct electrification but at the same time low energy efficiency, implying higher electricity demand. German electricity supply does not cover demand, hence according to the scenario description, more imports are needed. These imports are not visible in our model outputs though, on a yearly basis Germany is even exporting in the three scenarios, although notably less in National Transition, most likely because of the lower generation capacity in France.[23]

[22] Effects on other CORE countries are insignificant and therefore not shown.
[23] Apart from that, this may relate to the fact that the German NEP assumes the TYNDP 2022 DE scenario for other EU MS than Germany, while we assume TYNDP 2022 NT scenario for other EU MS than Germany and the Netherlands.

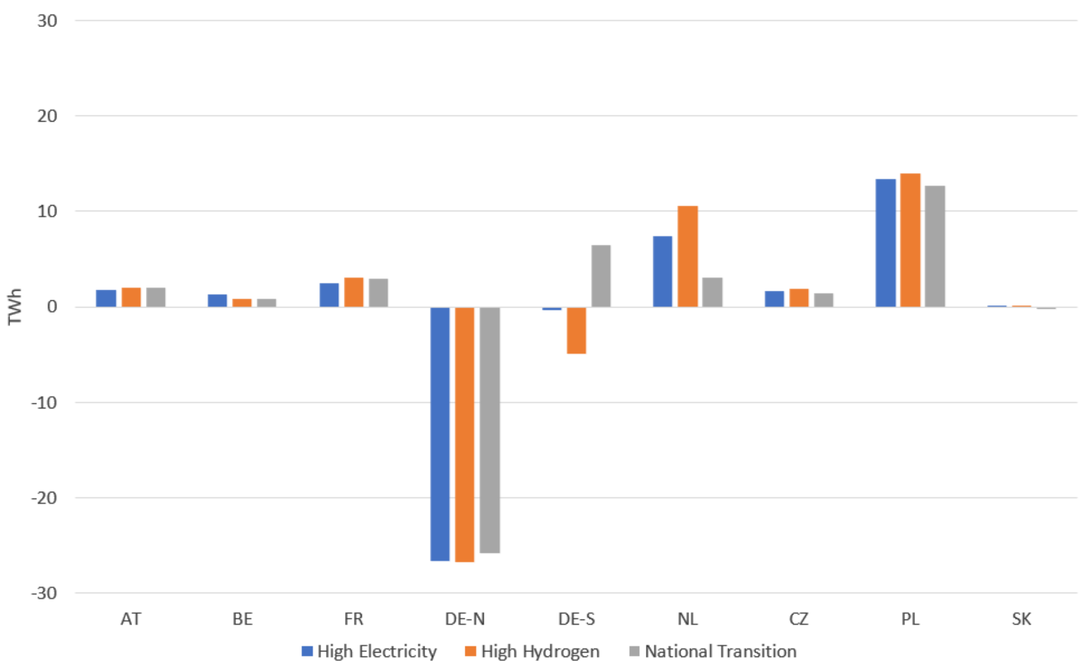


Figure 4.7: Changes in net imports in CORE countries due to DE2 BZ configuration

Electricity prices
Overall, the higher available cross-zonal network capacities in the DE2 BZ configuration decrease price differences across countries. Average electricity prices decrease mostly in Poland, Germany-South (notably in National Transition), Austria, and Switzerland. Poland is most affected as it shows highest electricity prices of all countries due to its coal-fired generation combined with higher fuel and CO_2 prices by 2035. Given the increase of cross-zonal network capacities, countries that are located at the Southern side of the German North-South network constraints can import more electricity from abroad at lower prices. Equally, countries at the Northern side such as Germany North and the Nordic countries exhibit average price increases due to more exports to zones with higher prices.

In most countries, electricity prices are highest in the National Transition scenario and lowest in the High Hydrogen scenario, with High Electricity in between. This reflects the larger imbalances of generation and demand across Europe in the former scenario, notably in Germany South. In the project alternative, Germany South is able to use more low marginal cost electricity produced in its own area due to less curtailment of wind generation as well as to import more cheap electricity from abroad replacing hydrogen and natural-gas fired generation, decreasing average prices compared to the base case, see Figure 4.8. Therefore, in National Transition the average volume weighted electricity price in Germany South decreases by 8.6 €/MWh due to an additional BZ (see Figure 4.11), while electricity prices decrease by 1.3 €/MWh and 2.2 €/MWh in scenarios High Hydrogen and High Electricity respectively (see Figure 4.9 and Figure 4.10). Recall that the effects of inclusion of more network constraints in wholesale electricity prices are part of the discussion of the redispatch effects in Chapter 3, and therefore the electricity price effects in this Chapter are due to the effects of more available interconnection capacity only. As seen before, the significant lower prices in Germany South in National Transition compared to both the base case and other scenarios, result in a huge effect on the consumer surplus of Germany South; consumer surplus increases by about € 4.6 billion compared to about € 700 and € 950 million in High Electricity and High Hydrogen scenarios, respectively. Besides, National Transition shows the largest decrease of price differences between Germany South and surrounding bidding zones.

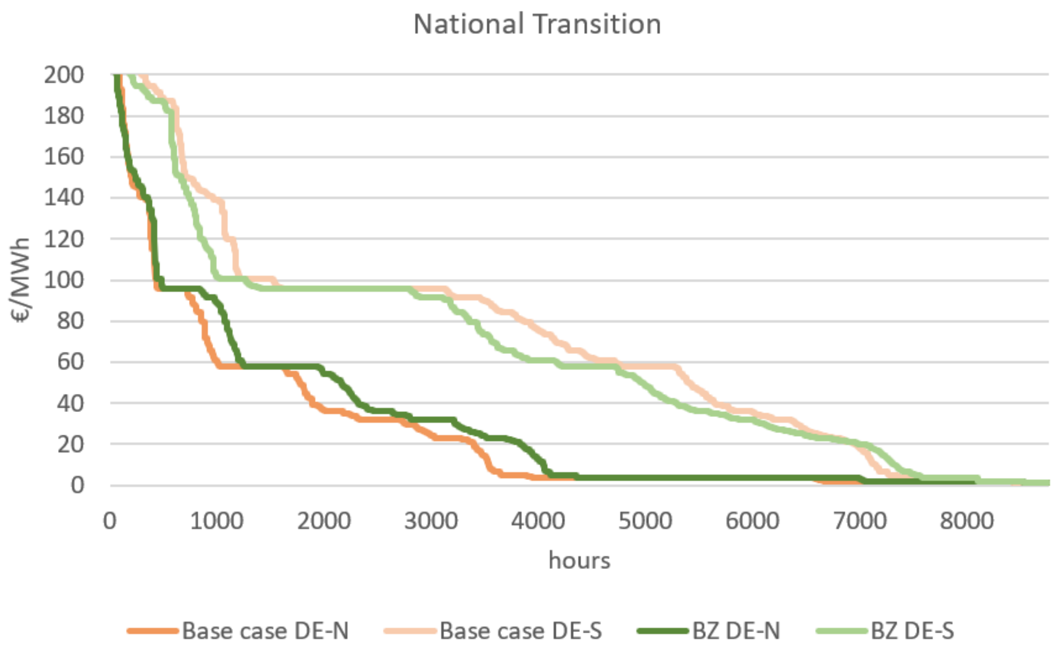


Figure 4.8: Electricity price duration curves for Germany North and South in the National Transition scenario

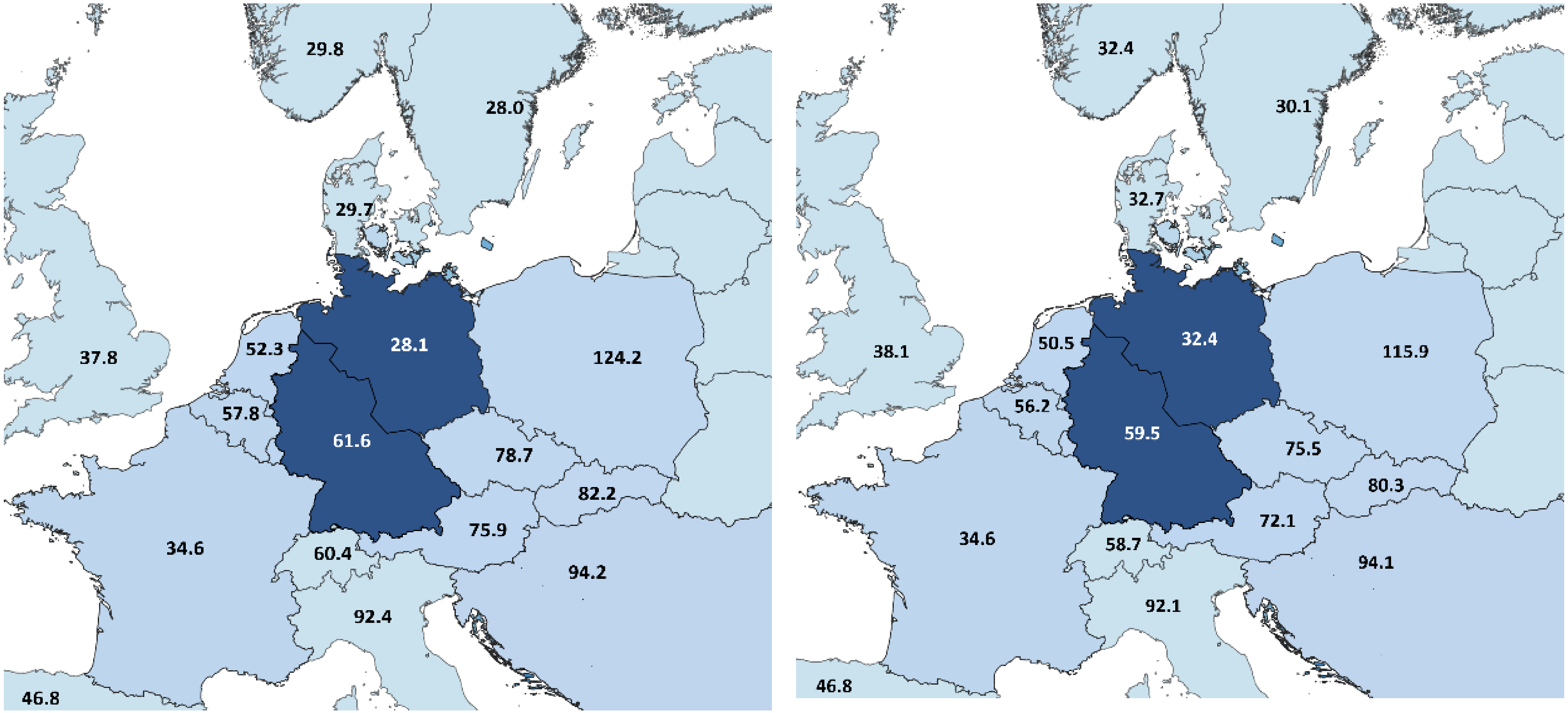


Figure 4.9: Average electricity prices in €/MWh in High Electricity scenario (left: base case, right: BZ case)

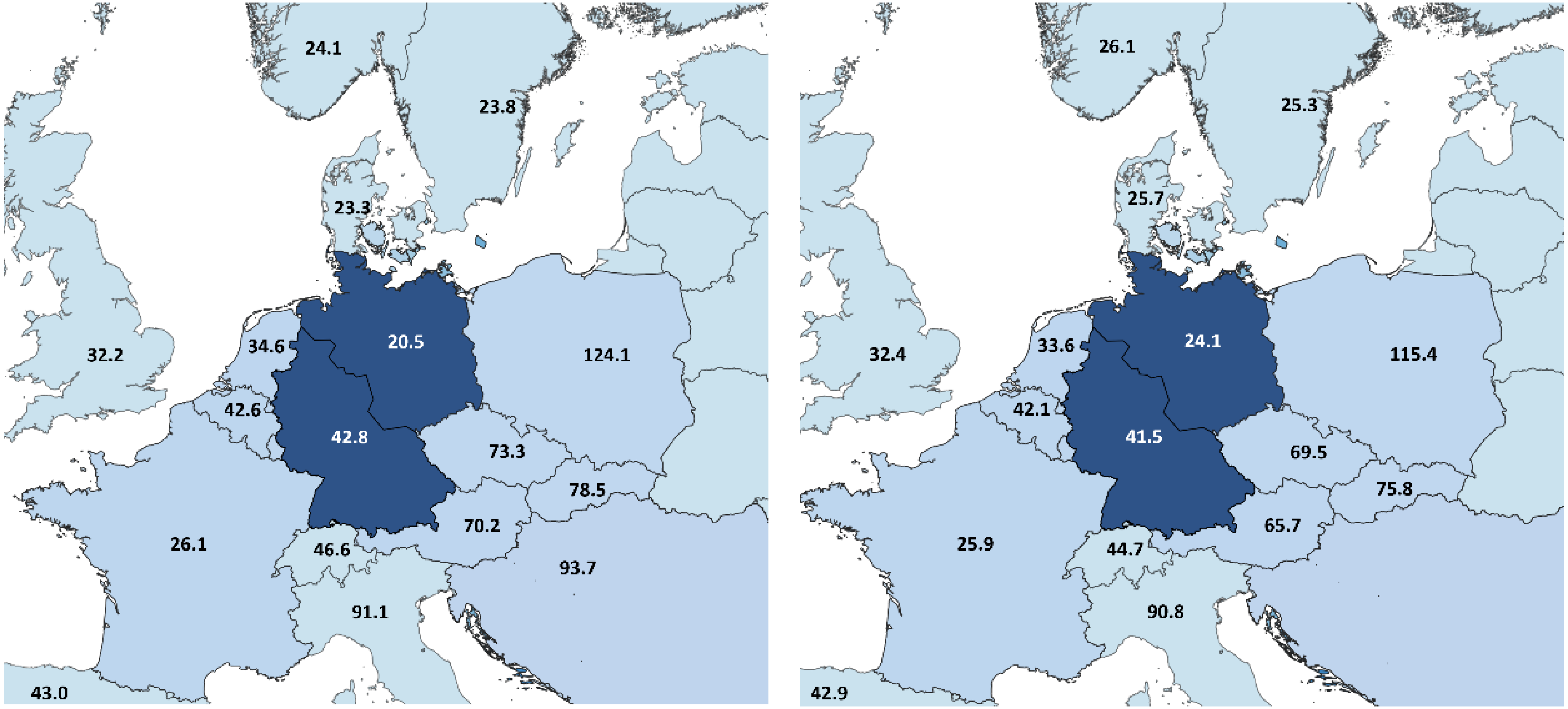


Figure 4.10: Average electricity prices in €/MWh in High Hydrogen scenario (left: base case, right: BZ case)

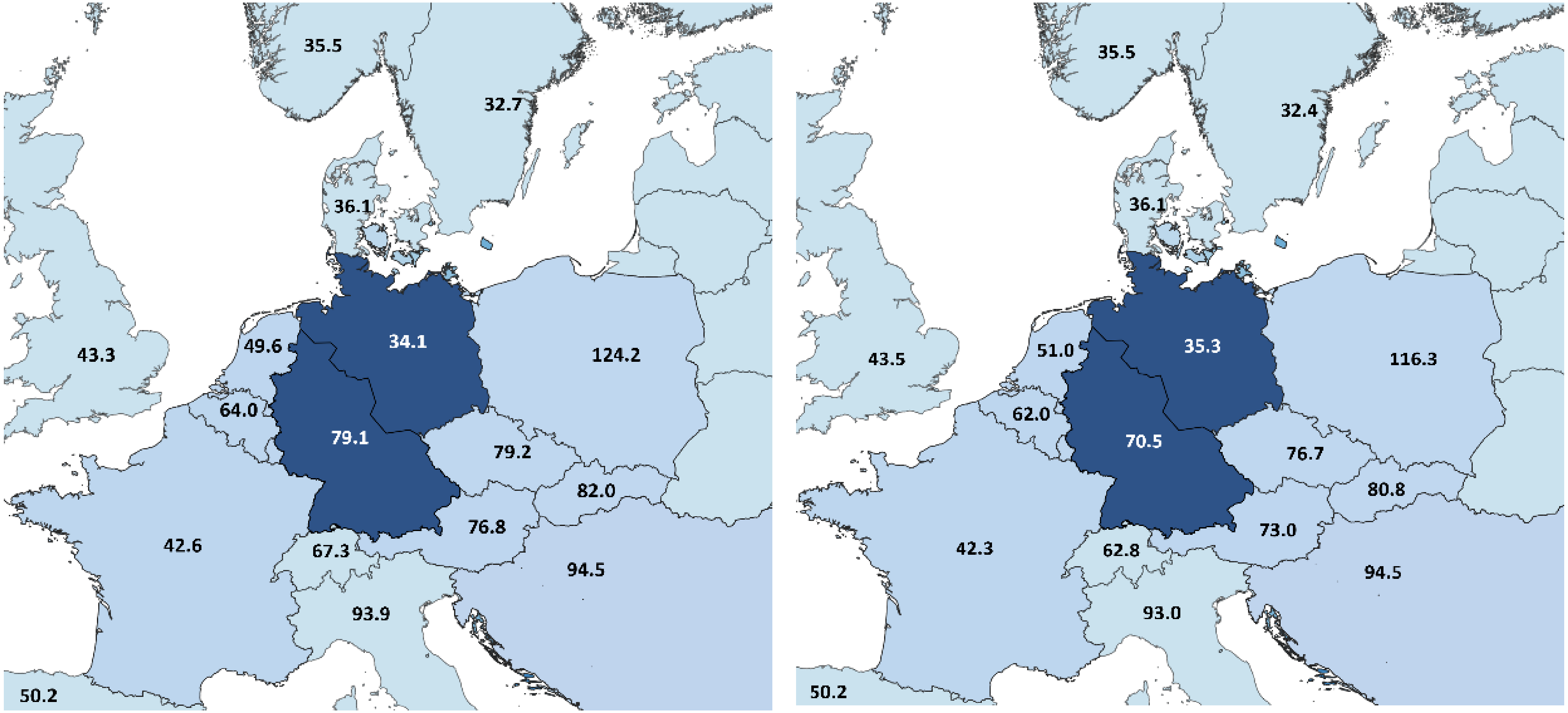


Figure 4.11: Average electricity prices in €/MWh in National Transition scenario (left: base case, right: BZ case)

4.2.2 CO_2 emissions

The more efficient generation dispatch in the project alternative compared to the base case decreases CO_2 emissions of the power sector. As shown in Figure 4.12, the main effect is visible in Poland due to lower deployment of coal-fired generation, while effects on other countries are often small. In all scenarios CO_2 emissions of the power sector are reduced by about 4 Mton, with High Hydrogen scenario as lower boundary and National Transition scenario as higher boundary (see Table 4.3). Hence, the CO_2 emission reduction effect of this BZ configuration is robust.

Table 4.3: Total CO_2 emissions per case and scenario

[in Mton]	Country case	Base case	BZ case
High Electricity	19.4	21.3	17.5
High Hydrogen	16.2	17.1	13.4
National Transition	21.3	24.0	20.3

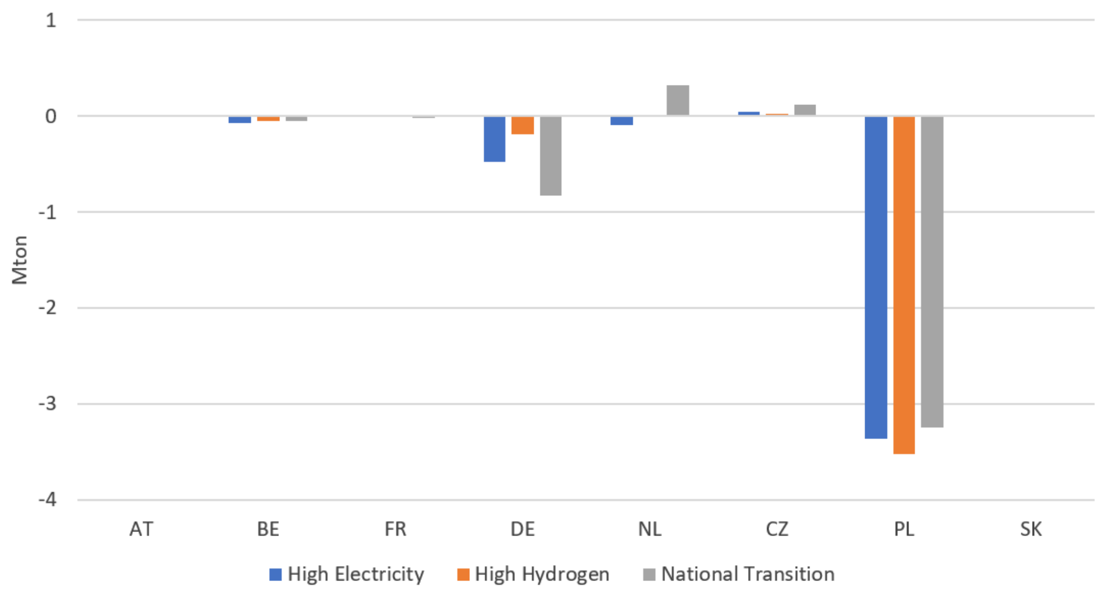


Figure 4.12: Changes in CO_2 emissions of the CORE countries due to DE2 BZ configuration

4.3 Robustness of DE4 BZ configuration

4.3.1 Socio-economic welfare

The DE4 BZ configuration presents positive net social welfare effects in all scenarios, from € 3986 million in the High Electricity scenario, € 4233 million in High Hydrogen scenario, to € 4581 million in the National Transition scenario for EU-27+. Hereafter, the effects on the SEW components of the DE4 configuration are explored for the different scenarios. Next, a description of the underlying demand and supply parameters for each scenario is provided to contextualize the SEW results.

SEW components
Producer surplus decreases across the three scenarios when comparing the BZ case against the base case both at CORE and EU-27+ level. This entails a total decrease of € 14 billion, € 2.8 billion and € 8.9 billion in the High Electricity, High Hydrogen and National Transition scenarios respectively. This decrease results from lower electricity prices for generators in the majority of the CORE countries due to higher cross-border trade with additional German BZs. This does not hold for generators in the Northern German BZs (Germany Northwest and Northeast) as well as in France, which increase their profits due to higher production, exports, and electricity prices. Outside the CORE region, a more diverse trend in producer surplus is visible, with Nordic generators usually experiencing a net increase due to higher exports and higher prices across the scenarios.

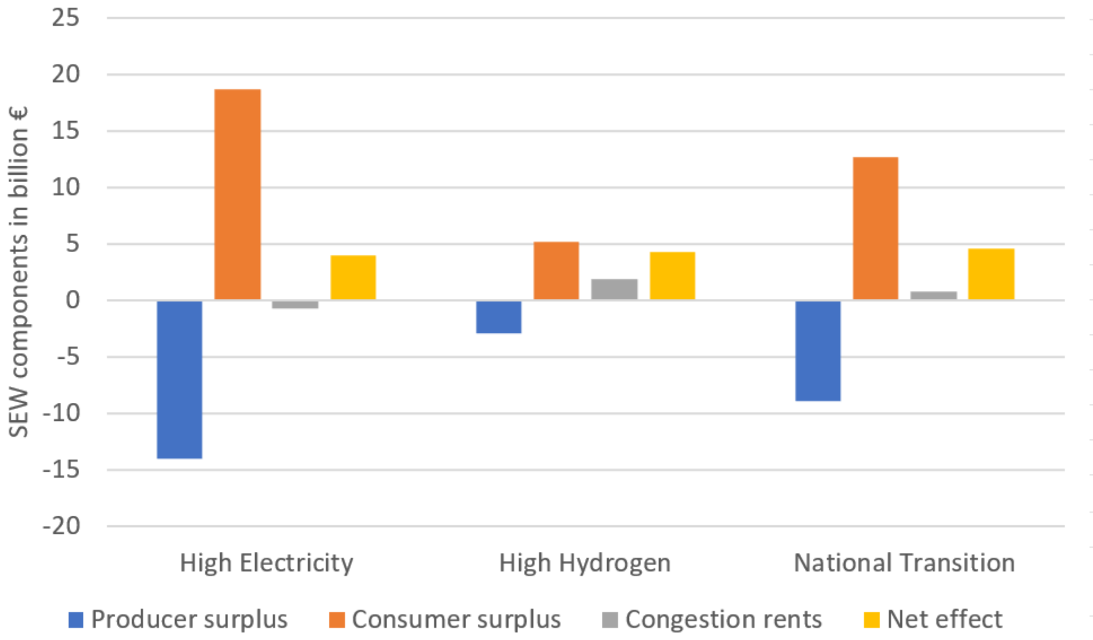


Figure 4.13: Incremental SEW effects of bidding zones of the DE4 BZ configuration in EU-27+ in 2035

Consumer surplus increases in all scenarios, both at CORE and EU-27+ level. This increase is always higher than the total decrease of producer surplus in the scenarios, hence this SEW component is the main driver of the overall net SEW increase. Again, this is mainly driven by the decrease in electricity prices across countries, and therefore a higher deployment of conversion options. As shown in Figure 4.13, consumer surplus is highest under High Electricity, followed by National Transition and lastly by High Hydrogen. This is explained by large price changes in the UK and the Netherlands in High Electricity, while the increase of demand mainly due to the conversion options is smaller than in the other scenarios. This could relate to the fact that High Electricity presents the highest electricity demand at EU-27+ level, reducing the scope for further increase of demand.

In the High Electricity scenario, the Netherlands is among the countries mostly affected by more available interconnection capacity due to bidding zones. In the base case, Dutch demand surpasses available generation, resulting in a very high average electricity price, and sometimes even involuntary demand curtailment. Given the deployment of redispatch, Germany West can import less from the Northern German BZs, and therefore exports less to the Netherlands. With more available interconnection capacity, higher imports of the Netherlands result in diminishing electricity prices and a large increase in consumer surplus. Besides, involuntary demand curtailment does not occur anymore. The UK shows an even larger increase in consumer surplus, resulting from less exports to Continental Europe. The consumer surplus of both countries explains about two-third of the total increase of consumer surplus in High Electricity in Figure 4.13. In the other scenarios, the Southern German BZs (DE-W and DE-S), and other CORE countries, such as Belgium and Poland show higher imports, driving down electricity prices and boosting consumer surplus.

Overall congestion rents increase for the CORE region in all scenarios, with largest effect seen in Austria, Poland, Slovakia, and Czech Republic. Again, the higher available interconnection capacity, notably between West and East Europe, leads to convergence of electricity prices across Continental Europe. The High Electricity scenario is an exception at EU-27+ level though, with a decrease of congestion income of about € 700 million compared to the base case. The main driver of this difference is the UK. In all scenarios, congestion rents in the UK are reduced, but mainly in High Electricity. The UK exports to Continental Europe through Netherlands, Belgium and France, but once more interconnection capacity becomes available the Netherlands replaces imports from the UK by imports from other bidding zones, notably DE-NW.

The changes of SEW components are lowest in High Hydrogen, driven by its lower electricity demand compared to the other scenarios. High Electricity has the highest increase and decrease in producer and consumer surplus respectively, but the reduction in congestion rents reduces the net SEW effect, while National Transition achieves the highest net SEW. Despite these underlying effects, the DE4 configuration can be considered as robust in terms of the direction and size of the total SEW effect. The distribution of social welfare over the different stakeholders of the CORE countries is largely robust as well, as we see similar trends in the SEW components for these countries, with the exception of the development of congestion rents in the High Electricity scenario.

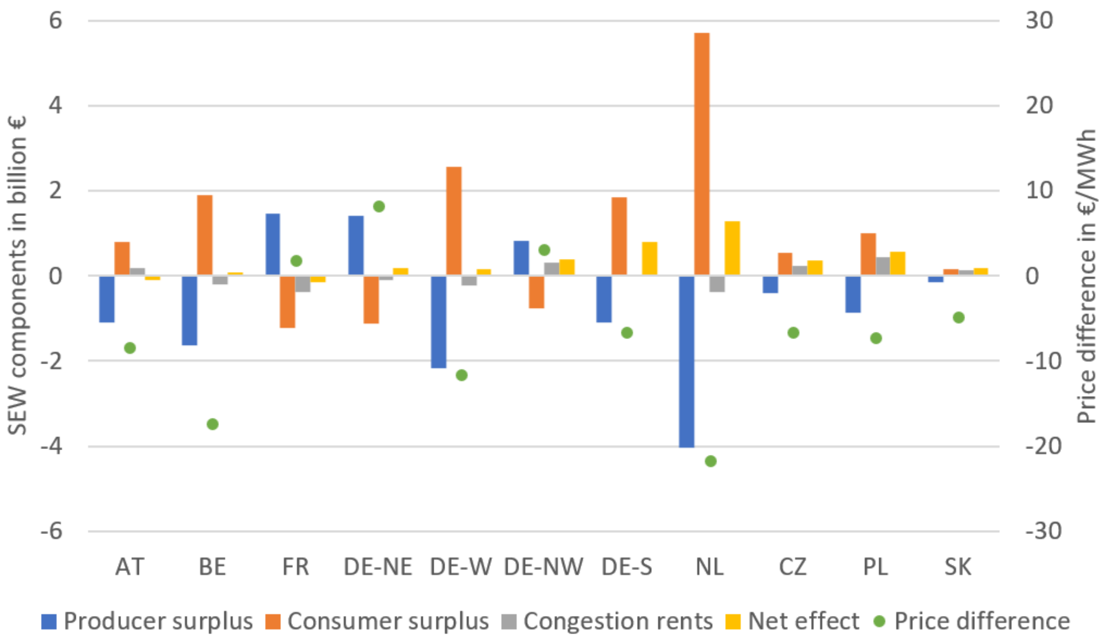


Figure 4.14: Incremental SEW effects of bidding zones for the CORE countries in the High Electricity scenario

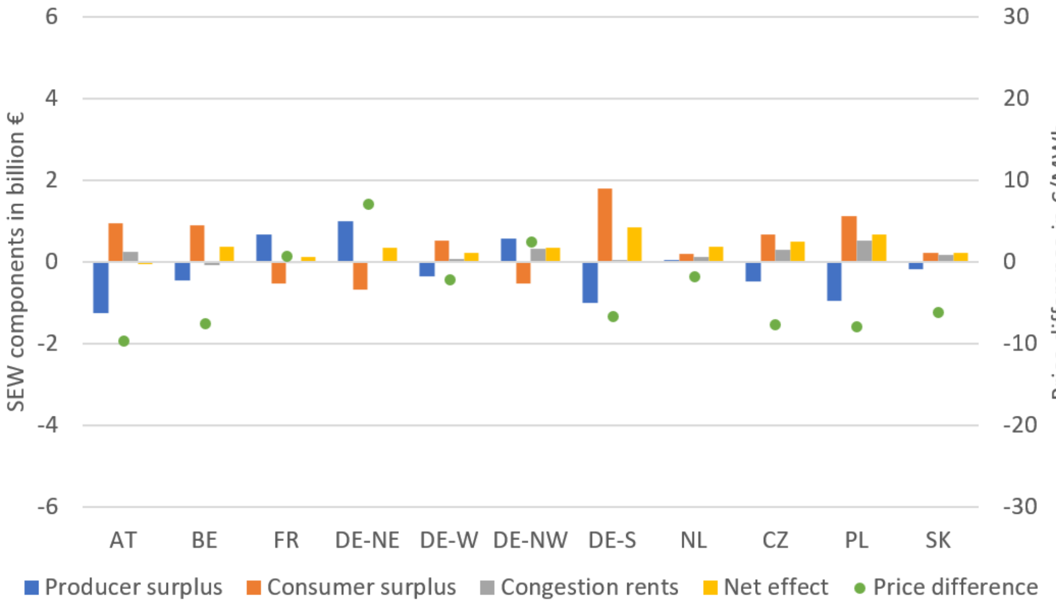


Figure 4.15: Incremental SEW effects of bidding zones for the CORE countries in the High Hydrogen scenario

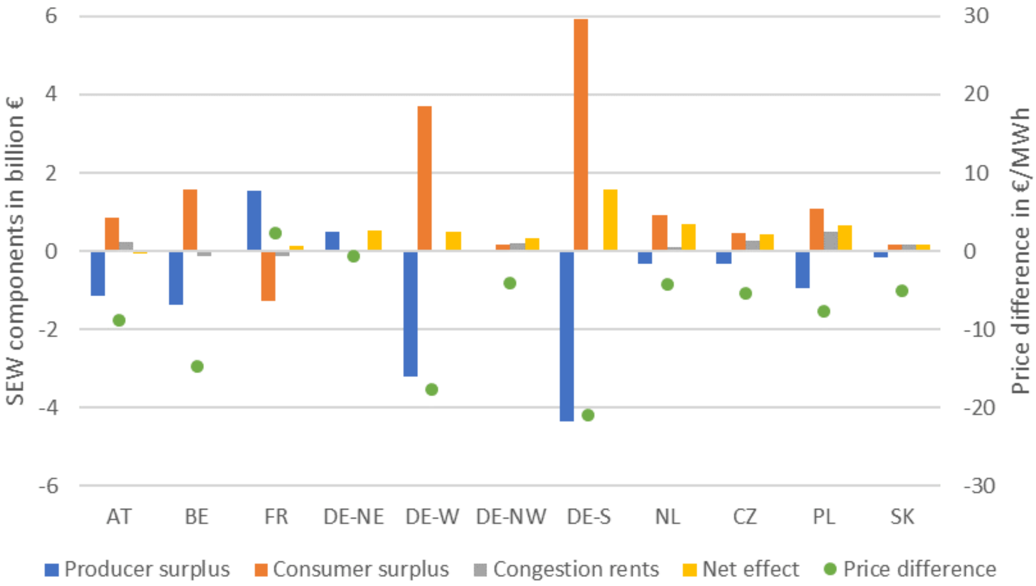


Figure 4.16: Incremental SEW effects of bidding zones for the CORE countries in the National Transition scenario

Drivers for highest and lowest social welfare effects

Demand level and flexible demand deployment
The effect of this BZ configuration on the flexible demand components is summarized in Figure 4.17. The increase in electrolysis and Power-to-Heat in BZs in Southern Germany (DE-W and DE-S), as well as the corresponding decrease in BZ located in Northern Germany (DE-NE and DE-NW) is visible in all three scenarios. In National Transition, the Power-to-Heat increases mostly in DE-S with highest industrial demand of Germany. This results from a significant reduction in the electricity prices in DE-S with higher availability of interconnection capacity. France and the Netherlands present a much lower increase of demand. While Germany and France show similar trends across the scenarios, the

Netherlands shows a marginal net increase in High Electricity and in High Hydrogen, and a net decrease in National Transition, with around 2 TWh less of electrolysis demand due to electricity prices that exceed the opportunity costs of the electrolysers.

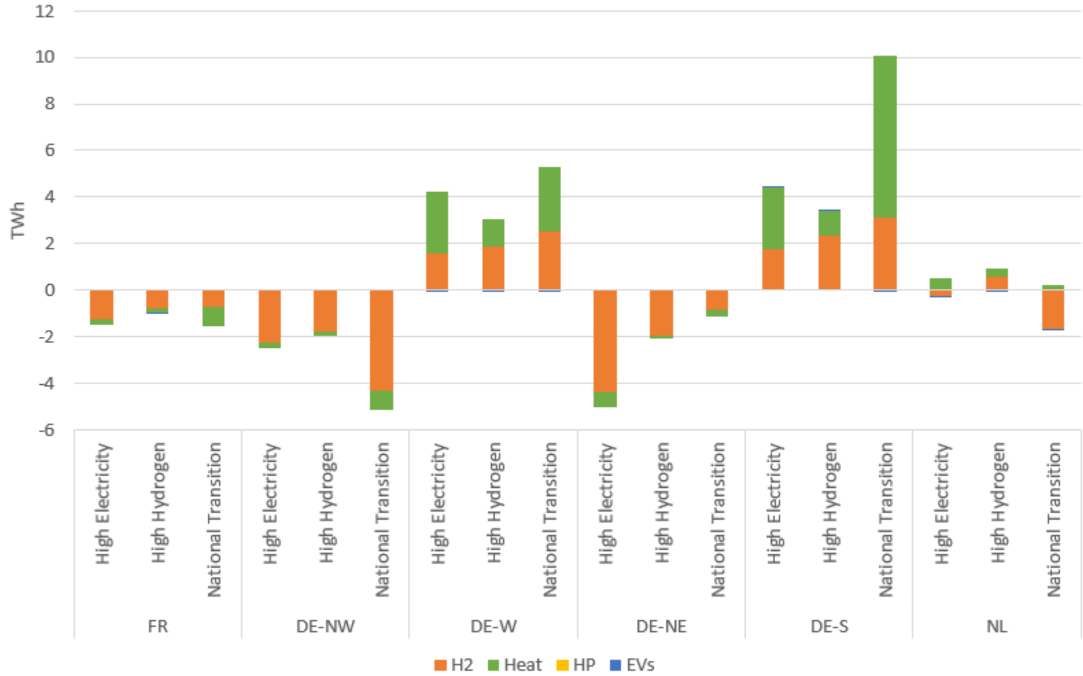


Figure 4.17: Changes in electricity consumption in France, German BZs, and the Netherlands due to DE4 BZ configuration

Generation mix
Figure 4.18 illustrates the changes in the generation mix under the BZ case. In the German Northwest region, the increase of cross-border capacity allows for better integration of wind energy, which reduces curtailment up to 30 TWh in the National Transition scenario. Hence, the need for generation from dispatchable capacity like gas and biomass in DE-S is reduced too. Interestingly, there is more curtailment in the DE-NE BZ compared to the base case, despite having more net exports. This is a result of replacement of generation mainly in DE-NW. For France, there is an increase in production, notably nuclear, compared to the base case again due to more exports.

As seen before, the Netherlands shows a less robust behavior across the scenarios. Under High Electricity, there is a reduction of dispatchable generation from gas, H2-to-power, as well as curtailment of wind. In contrast, in High Hydrogen and especially in National Transition production increase. In High Electricity, the electricity demand is fulfilled with more electricity import, mainly from DE-NW, and lower dependency of more expensive high marginal cost units such as hydrogen and natural gas-fired power plants. In the other two scenarios, the Netherlands is a net exporter, notably in National Transition with a reduction of wind curtailment by about 5 TWh of production, together with a marginal increase of gas and other dispatchable units.

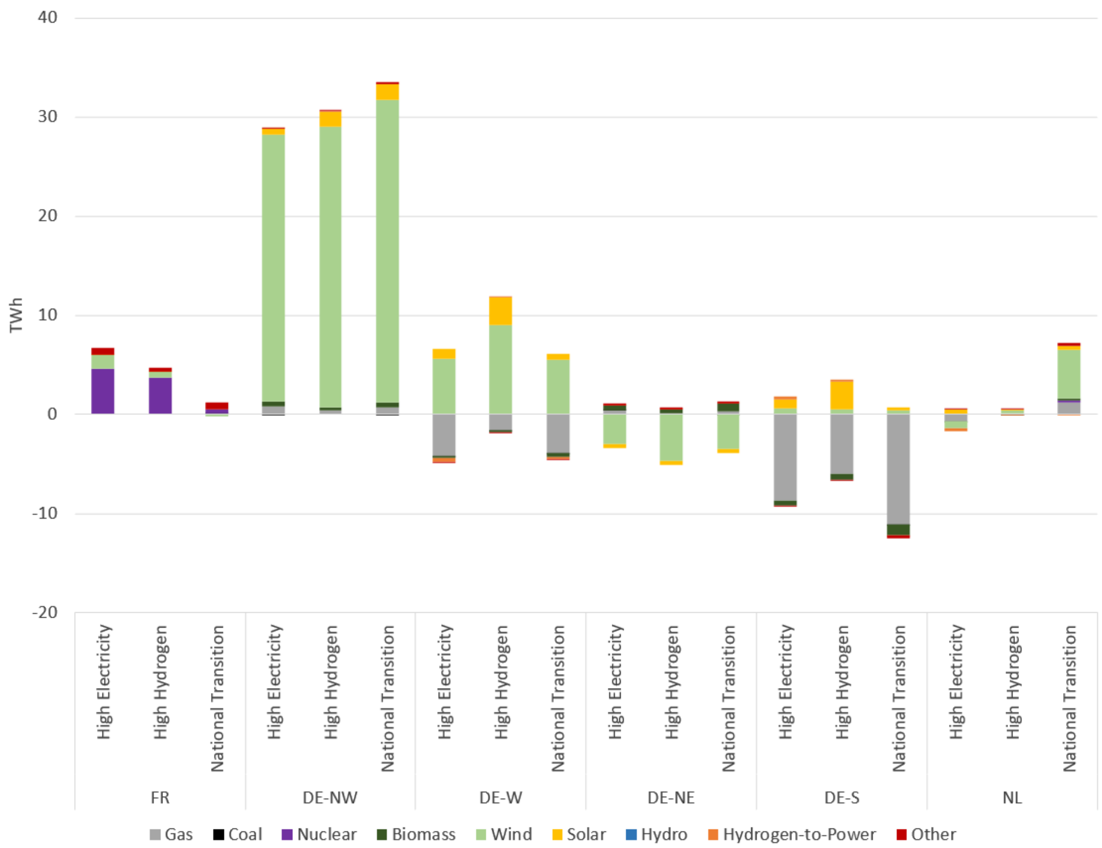


Figure 4.18: Changes in electricity generation in France, German BZs and the Netherlands due to DE4 BZ configuration

Net imports and exports

Figure 4.19 shows the differences in net imports for the main CORE countries for the DE4 BZ configuration. Given higher generation and lower demand, Germany Northwest becomes a net exporter, while the lower production and higher demand implies that Germany South is a net importer in all scenarios. The net positions of Germany West and Germany Northeast change only to a limited extent and depend on the scenario at hand. Under High Electricity and National Transition, DE-NE is a net exporter, and DE-W is a net importer, while this is reversed in High Hydrogen. In High Hydrogen, VRE production in Germany West increases due to less curtailment, resulting in net exports. Meanwhile, higher curtailment of domestic generation in German Northeast, and an increase in demand from electrolysis, result in slightly higher imports. In the National Transition scenario, an increase of net exports in the Netherlands and a rise in imports of Southern Germany can be observed, for which the reasons have been discussed before.

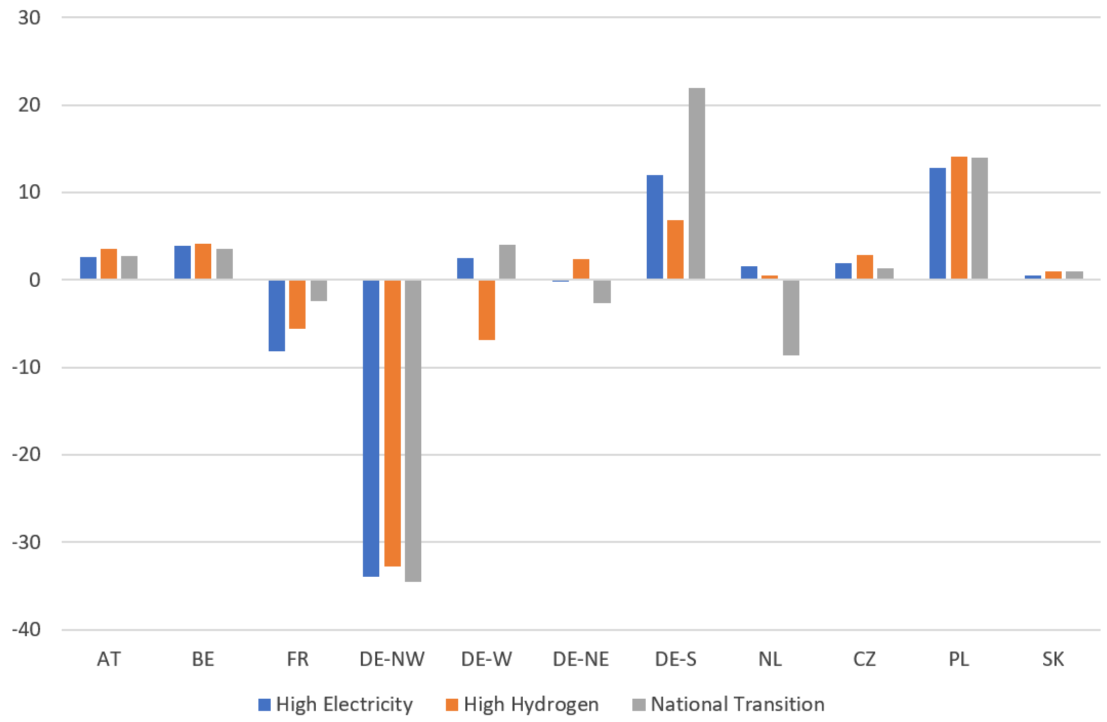


Figure 4.19: Changes in net imports in CORE countries due to DE4 BZ configuration

Electricity prices

Electricity prices reflect the price decreasing effect of additional interconnection capacity. High Hydrogen shows the lowest electricity prices of the three scenarios, mainly driven by its lower inflexible demand level.

Figure 4.18-Figure 4.20 show the changes of electricity prices due to the DE4 BZ configuration for High Electricity and National Transition respectively. These scenarios show the lowest and highest SEW effect respectively, but at the same time both scenarios show a similar trend in the reduction of electricity prices across countries, although with different magnitude.

In the High Electricity scenario, electricity prices decrease significantly across a large number of countries in Continental Europe compared to the base case. But notably the Netherlands experiences a considerable decrease in its average electricity price under this scenario, thanks to higher possibilities for imports as discussed earlier.

The effect of additional interconnection capacity is most significant for the National Transition scenario, which initially showed the lowest price convergence due the higher imbalance between demand and generation of this scenario, notably considering Germany.

The price convergence can also be inferred from the price duration curves of the German BZs under the base case and the BZ case for the High Electricity scenario (see Figure 4.23). This figure clearly shows the effect of cross-border-trade on electricity prices. DE-NW and DE-NE become net exporters and face higher electricity prices, while DE-W and DE-S benefit from higher imports and price reduction.

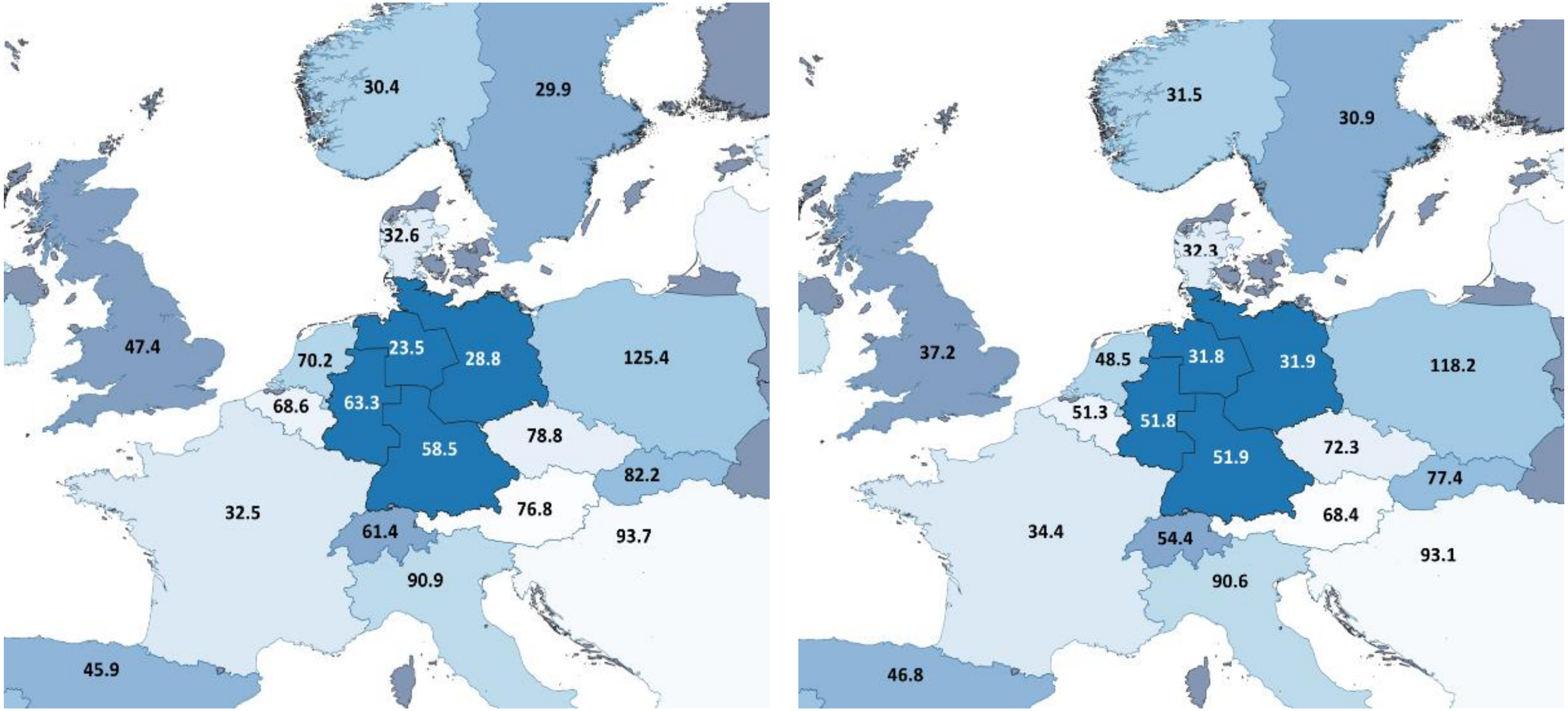


Figure 4.20: Average electricity prices in €/MWh in High Electricity scenario (left: base case, right: BZ case)

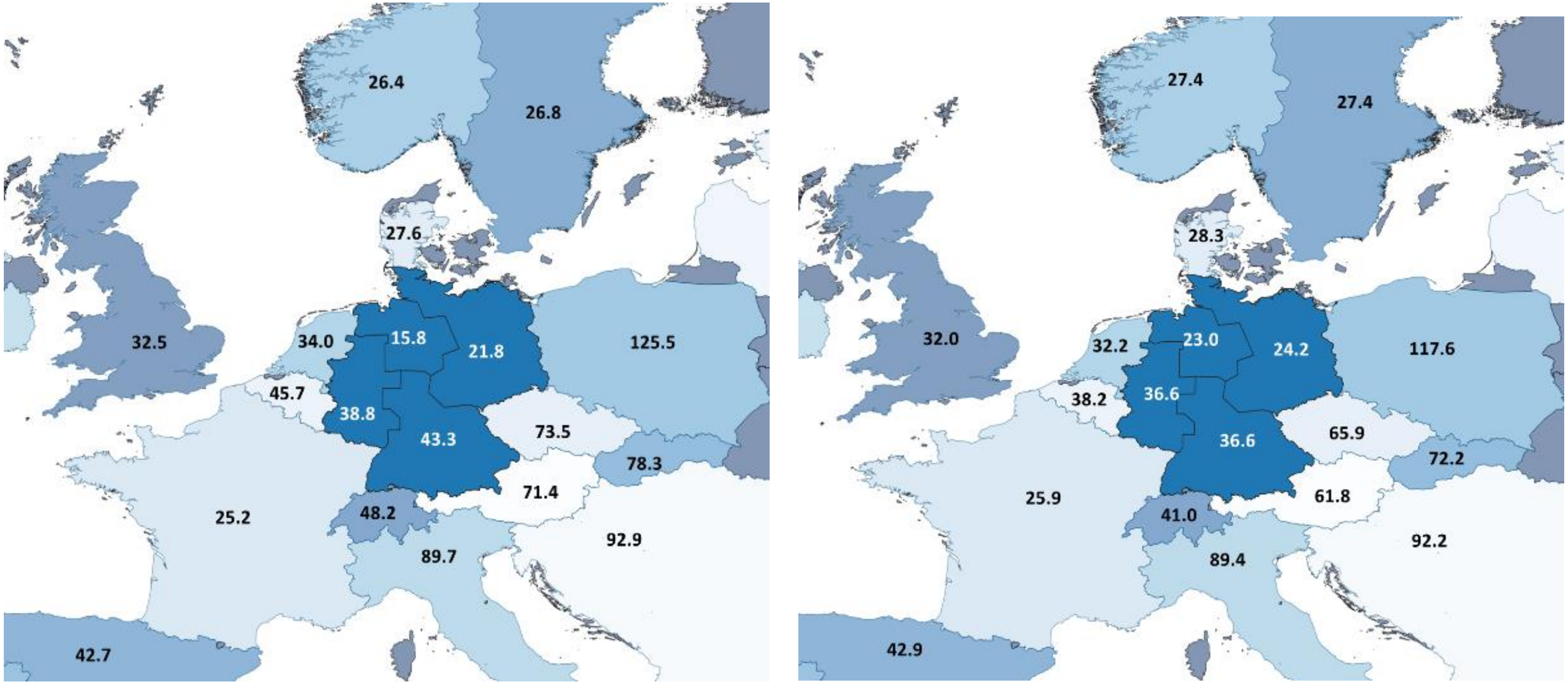


Figure 4.21: Average electricity prices in €/MWh in High Hydrogen scenario (left: base case, right: BZ case)

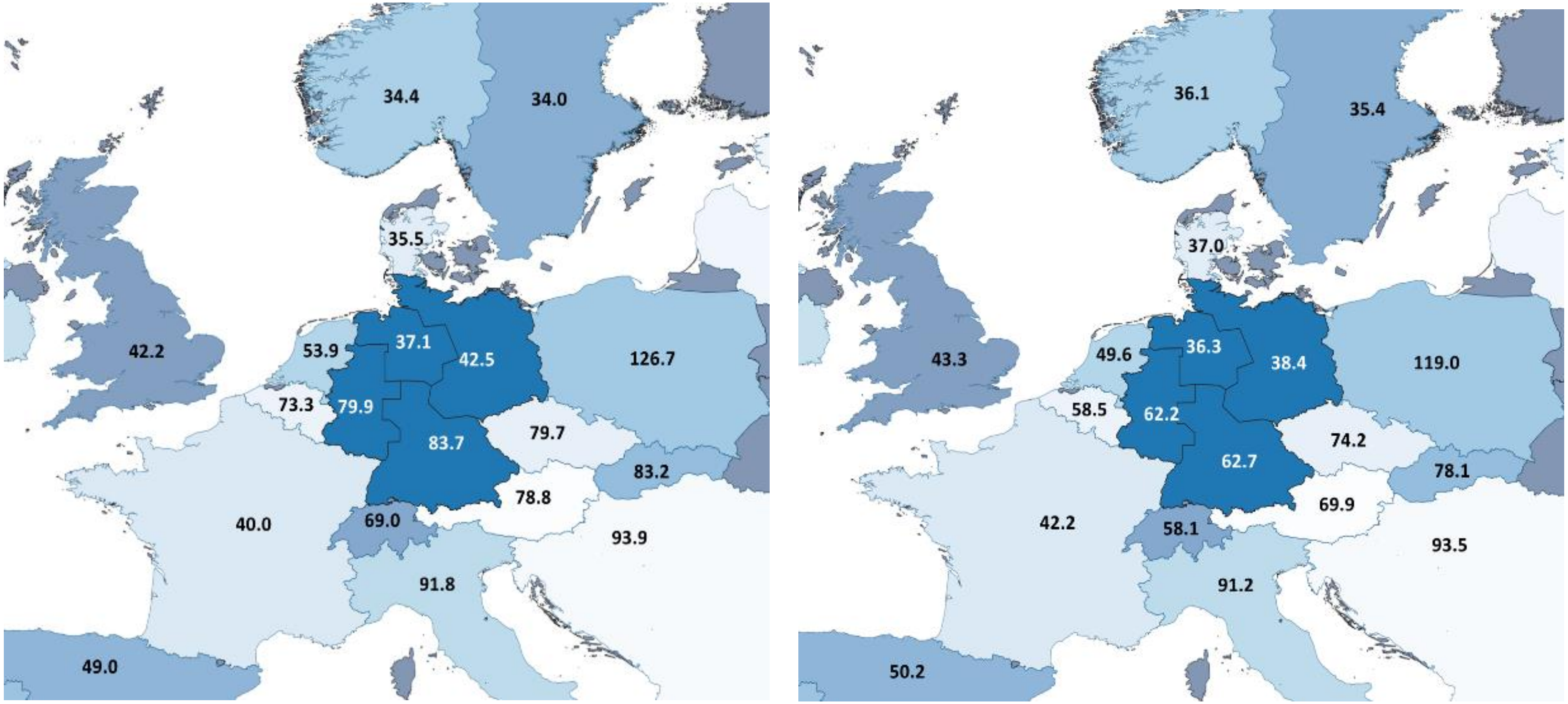


Figure 4.22: Average electricity prices in €/MWh in National Transition scenario (left: base case, right: BZ case)

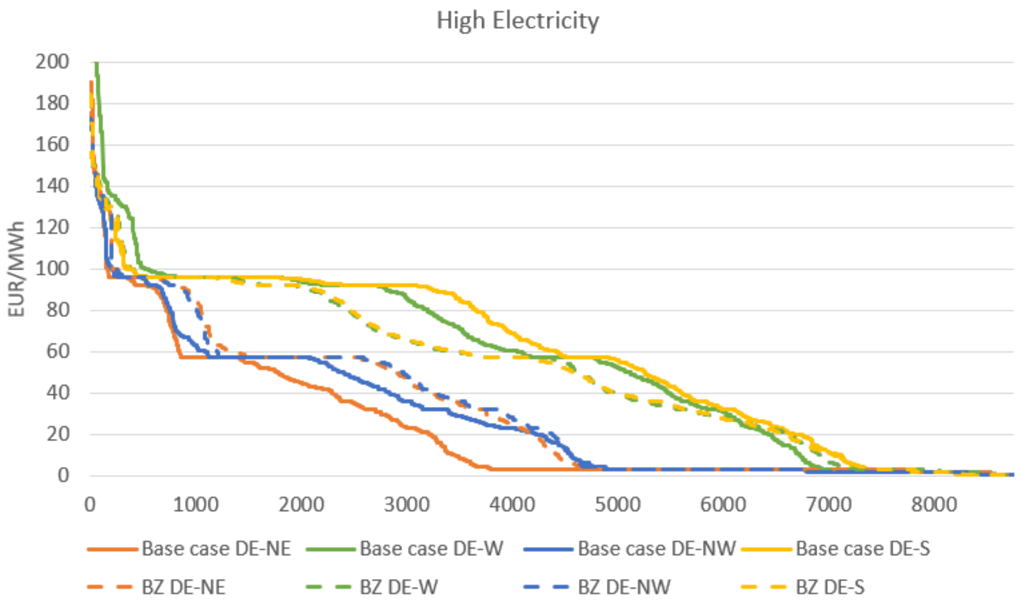


Figure 4.23: Electricity price duration curve for German BZs in the High Electricity scenario

4.3.2 CO_2 emissions

The total CO_2 emissions of EU-27+ power system are summarized per case and scenario in Table 4.4. The implementation of the DE4 BZ configuration reduces the CO_2 emissions in the European electricity system in all scenarios and is therefore robust. In the National Transition scenario the highest CO_2 emission reduction is observed, followed by High Electricity and High Hydrogen. The highest reduction is visible in the National Transition scenario due to the reduction of fossil generation in Germany, Poland, and other Eastern European countries.

Table 4.4: Total CO_2 emissions per case and scenario

[in Mton]	Country case	Base case	BZ case
High Electricity	21	26	20
High Hydrogen	18	21	15
National Transition	23	30	23

Figure 4.24 shows the differences in the power system's CO_2 emissions for the different scenarios in the CORE region. Germany and Poland exhibit the largest emission reductions due to the higher shares of VRE production in the system, ultimately reducing the generation from fossil-fuel fired units, notably from coal production in Poland.

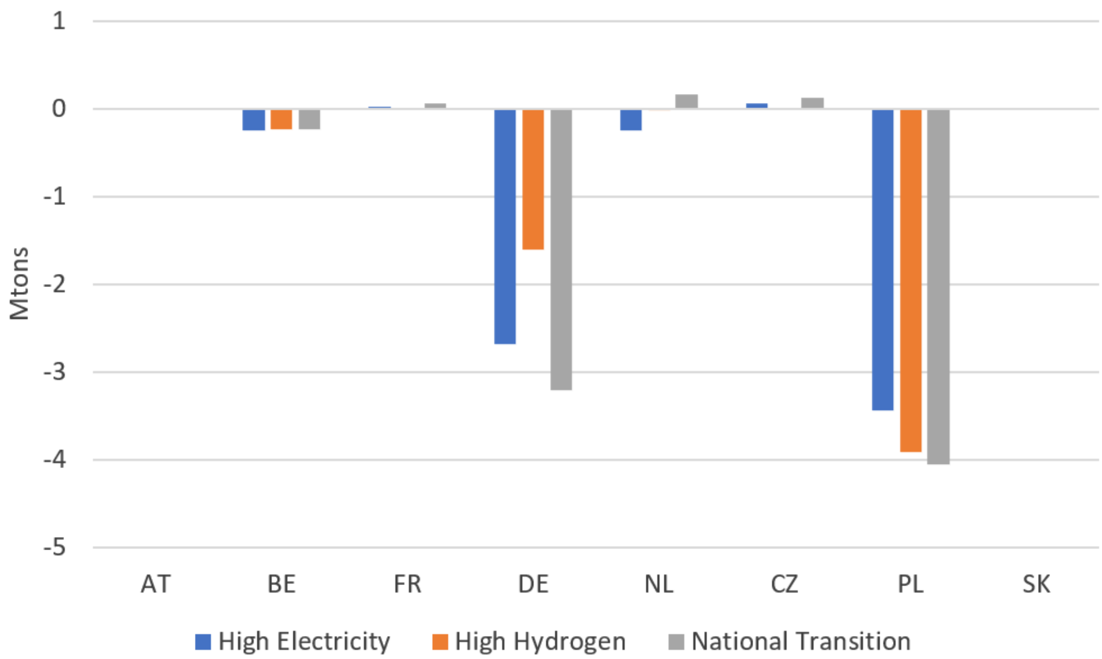


Figure 4.24: Changes in CO_2 emissions of the CORE countries due to the DE4 BZ configuration

4.4 Robustness of NL2 BZ configuration

4.4.1 Socio-economic welfare

The NL2 BZ configuration demonstrates positive net social welfare effects for EU-27+ in all scenarios, with benefits ranging from € 243 million in the High Electricity scenario, € 253 million in National Transition, to € 310 million in the High Hydrogen scenario. However, when compared to the net SEW effect of the German BZ configurations, the impact of the NL2 project alternative is relatively minor. The following analysis examines the different SEW components across the studied scenarios and explores the underlying demand and supply parameters to provide context to the SEW results.

SEW components

Producer surplus decreases across the three scenarios when comparing the project alternative against the base case at EU-27+ level, as is the case in the other BZ configurations. Because of increased cross-border trade, generators face lower electricity prices in countries with a more expensive generation mix, particularly in some Eastern European nations which in 2035 still rely on fossil fuels and encounter the corresponding CO_2 emission costs. Notably Poland, the Czech Republic, Slovakia, and Austria benefit from higher exports from countries that are characterized by a high share of VRE such as Germany. This decrease in producer surplus is partially reduced by producer surplus gains in other regions, such as the UK and the Nordics, whose producer surplus increases across all scenarios compared to the base case.

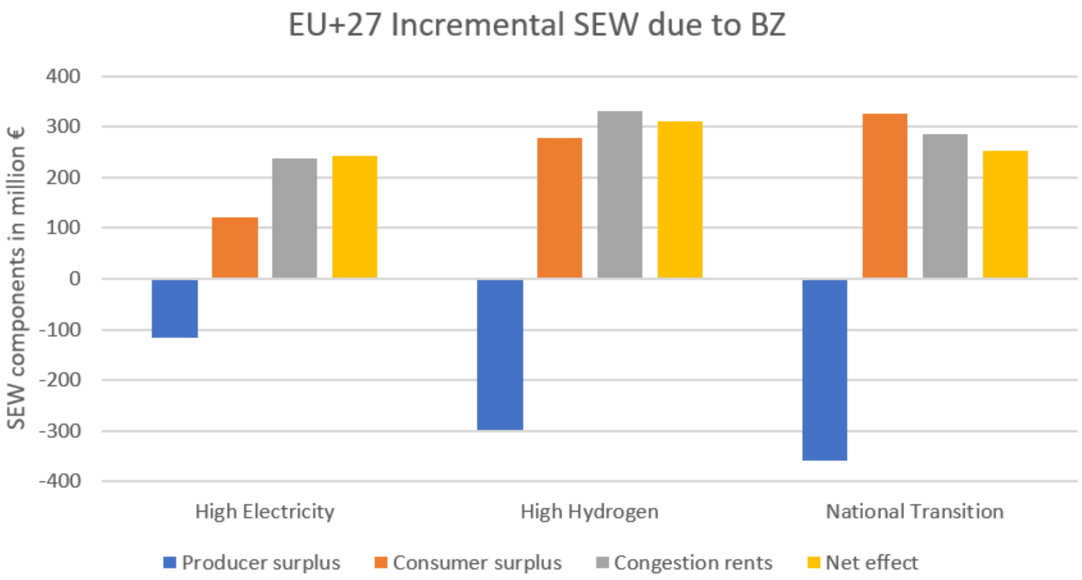


Figure 4.25: Incremental socio-economic welfare effects of the NL2 BZ configuration in EU-27+ in 2035

The overall decrease of producer surplus is largely counterbalanced by a corresponding increase of consumer surplus in the three scenarios, both at CORE and EU-27+ levels, as illustrated in Figure 4.25. This increase is driven by enhanced cross-border trade facilitated by the NL2 BZ configuration, which results in lower wholesale electricity prices for consumers in several countries.

Congestion rents rise across all scenarios, with the most significant effects observed in Germany and Eastern European countries. The generation mix differences between those countries, together with increased cross-border capacities, create favorable conditions for trade between low and high price zones, thereby boosting congestion rents. The counteracting effects of consumer and producer surpluses, imply that the increase of congestion rents is the main contributor to the net social welfare gains observed in the NL2 configuration, with the High Hydrogen scenario showing the greatest SEW increase.

Overall, the SEW effects of the NL2 BZ configuration show the same direction and size in different scenarios. The magnitude of the effects is smaller than for the DE2 and DE4 BZ configurations, but still significant, consequently this configuration is considered as robust.

The distribution of social welfare across various stakeholders is relatively consistent though, with similar trends observed in SEW components across the different scenarios. However, France and NL-N are exceptions in the High Hydrogen and High Electricity scenarios respectively (see Figure 4.26-Figure 4.28). We refrain from further discussion of these exceptions as the SEW benefits of these areas are insignificant.

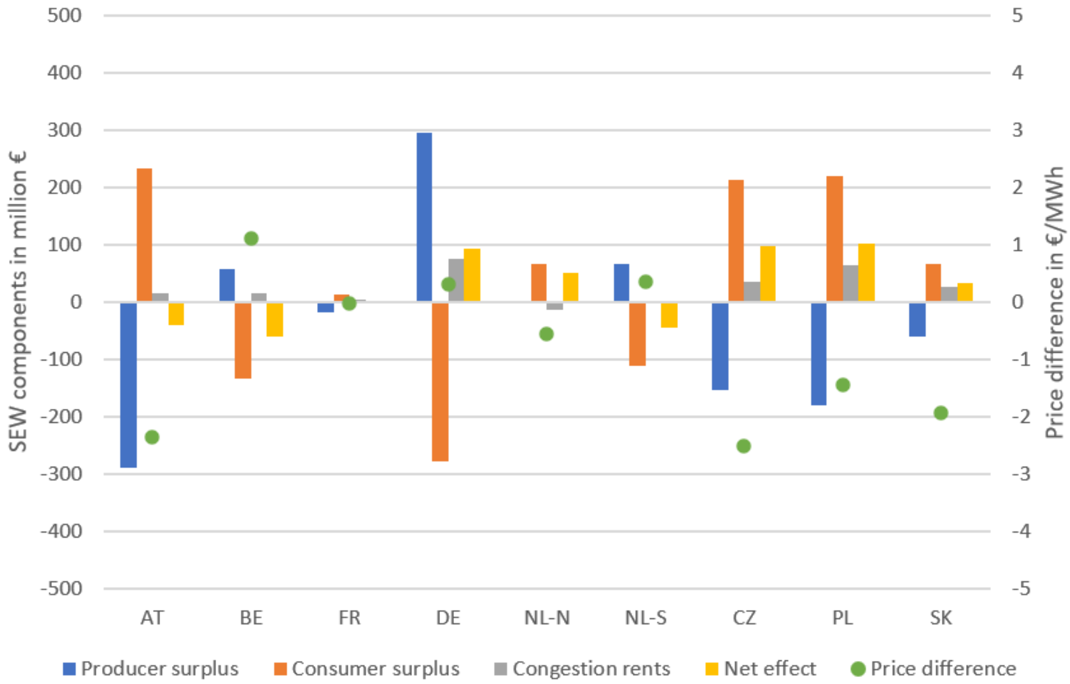


Figure 4.26: Incremental SEW effects of bidding zones for the CORE countries in the High Electricity scenario

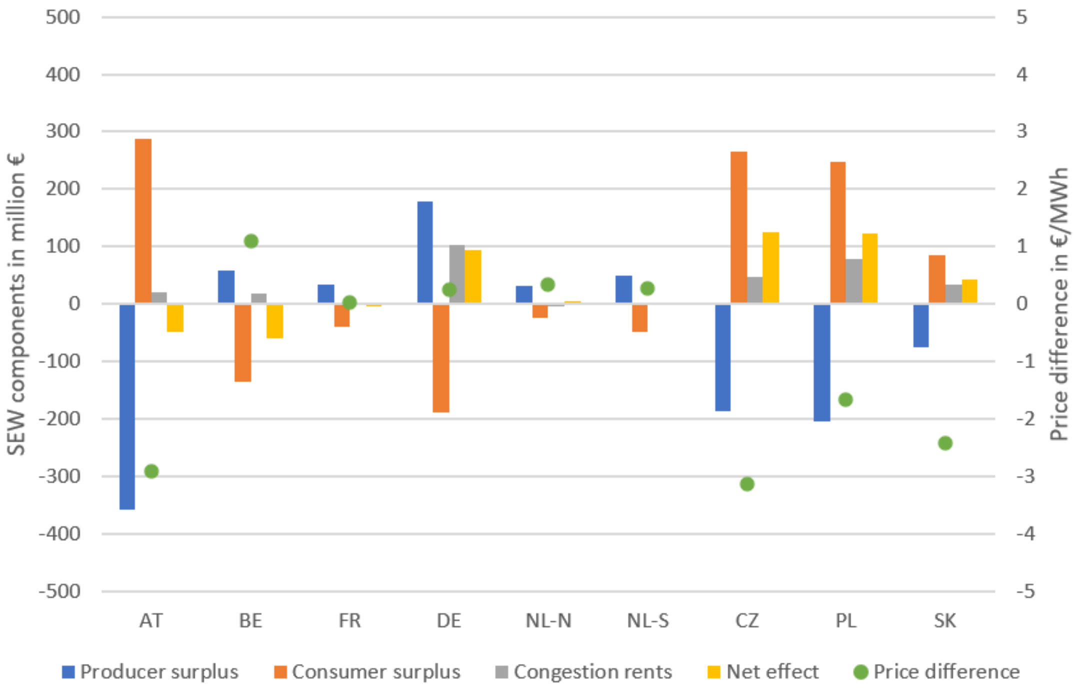


Figure 4.27: Incremental SEW effects of bidding zones for the CORE countries in the High Hydrogen scenario

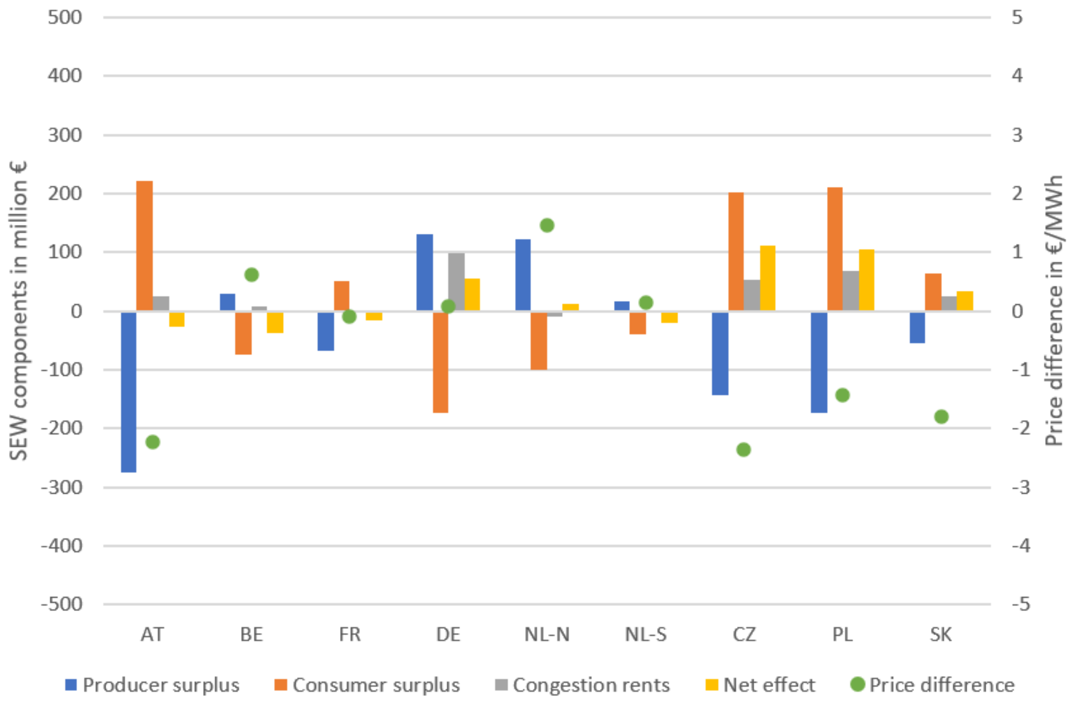


Figure 4.28: Incremental SEW effects of bidding zones for the CORE countries in the National Transition scenario

Drivers for highest and lowest social welfare effects

Demand level and flexible demand deployment

The NL2 BZ configuration has a limited impact on the demand side (see Figure 4.29). In Germany, the deployment of Power-to-X technologies decreases slightly across scenarios compared to the base case due to a modest increase of electricity prices.

In the Dutch BZs, the impact of the BZ configuration on electricity prices is reflected on the flexible demand deployment, notably in the High Electricity scenario. Electricity demand for electrolysis in Netherlands South decrease by approximately 1 TWh. Conversely, electricity demand for hydrogen production in Netherlands North increases by almost 1 TWh. These variations in flexible demand deployment are even smaller in High Hydrogen and National Transition. As previously mentioned, the High Hydrogen scenario exhibits the lowest electricity prices across EU-27+ due to its specific generation and demand conditions. In this context, the marginal increase in electricity prices in NL-S and NL-N does not trigger significant load-shedding effects for Power-to-X technologies, unlike in the High Electricity scenario. Meanwhile, in the National Transition scenario, the price difference in NL-S compared to the base case is minimal, and when combined with the low assumed installed capacity for flexible demand in the Netherlands, it results in the modest change in demand observed.

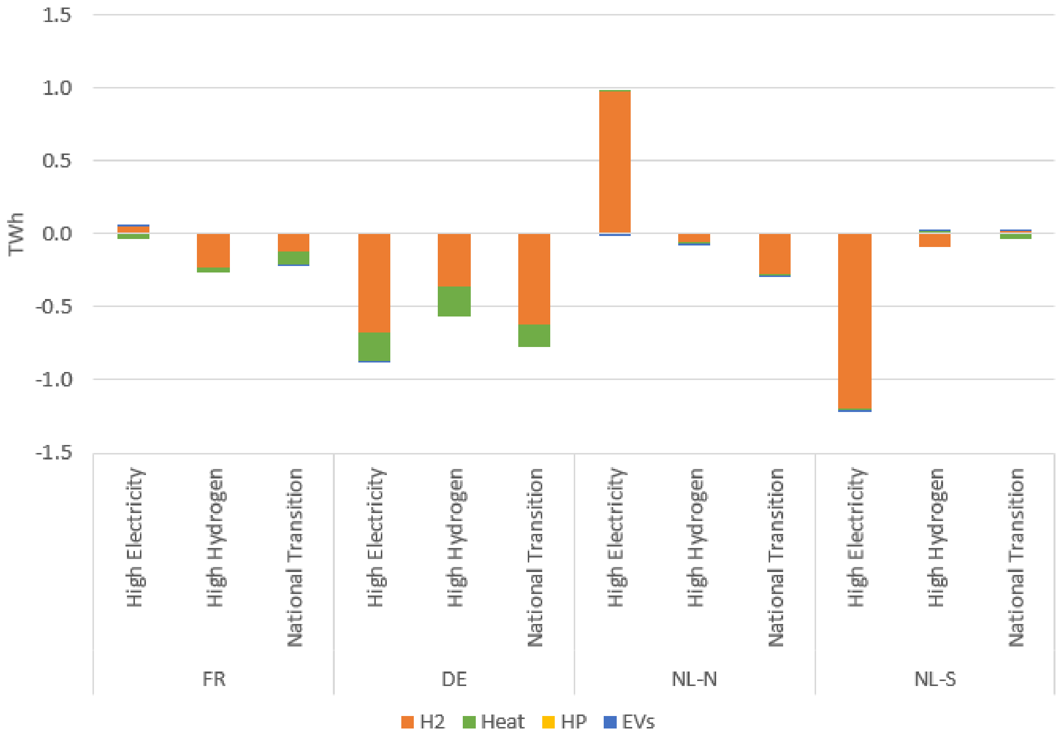


Figure 4.29: Changes in electricity generation in France, Germany and Dutch BZs due to NL2 BZ configuration

Generation mix
The NL2 BZ configuration has a relatively modest impact on the generation mix across different countries (see Figure 4.30). In Germany, the increase in generation primarily originates from reduced curtailment of wind and solar power, alongside a slight rise in biomass generation. However, there is a decrease in generation from other dispatchable sources, such as gas. In France, the scenarios show increased nuclear power generation, particularly in the High Hydrogen scenario, reflecting its role as a net exporter within the power system.

In the Netherlands, generation dispatch changes across scenarios and bidding zones. As can be seen in Figure 4.30, NL-N and NL-S exhibit an inverse relationship where a increase in generation in NL-S coincides with an decrease in NL-N, and vice versa. This is largely due to changes in wind curtailment in both areas compared to the base case.

Under National Transition, this effect becomes more pronounced while its direction changes due to scenario conditions. Hence, generation in NL-N increases by almost 2.5 TWh from wind and solar-pv while generation in NL-S decreases by about 1 TWh. As previously mentioned, this scenario is characterized by a higher electricity demand in Germany, leading to a larger need for imports for Germany from abroad. Given the higher available interconnection capacity between the Netherlands and Germany, generators in Netherlands North increase their production and export more electricity to Germany. As a result, the electricity prices in NL-N rise significantly in National Transition compared to the base case, with the largest increase among all three scenarios.

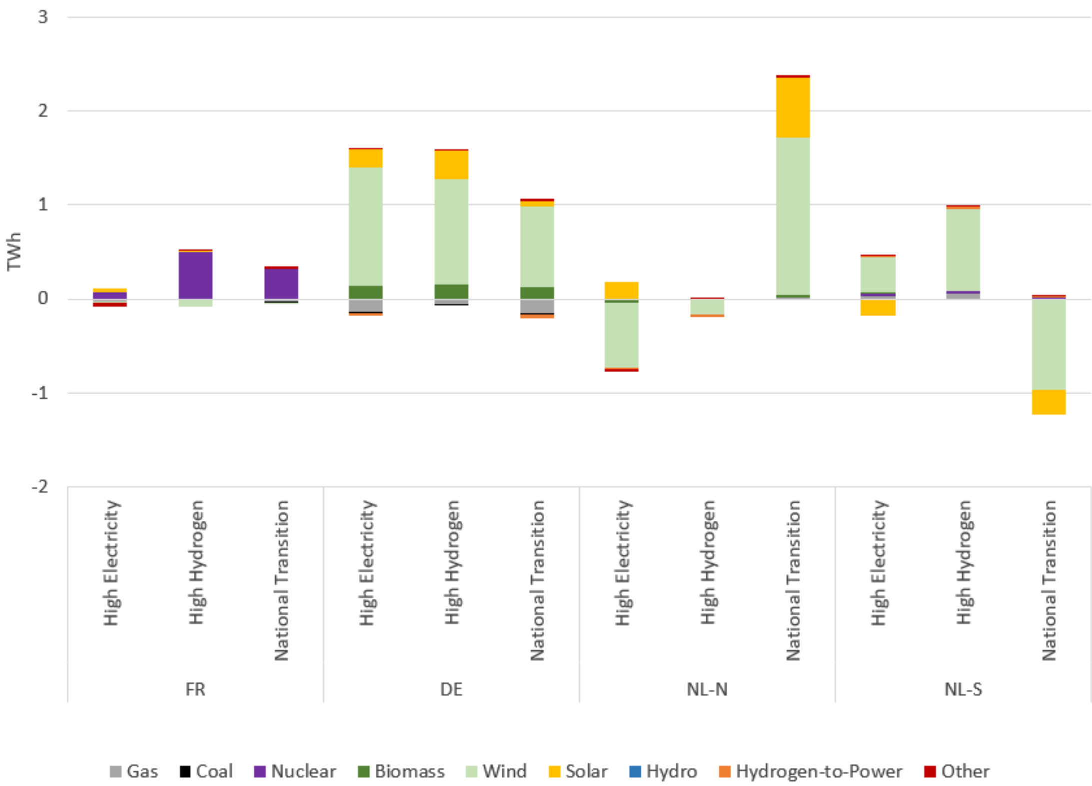


Figure 4.30: Changes in electricity generation in France, Germany and Dutch BZs due to NL2 BZ configuration

Net imports and exports

Given this BZ configuration, marginal changes in net imports and exports are observed among the various CORE countries (see Figure 4.31). Germany exports more due to its excess generation relative to domestic demand. In contrast, net imports of Poland, Czech Republic and Austria increase, following a similar pattern as in the other BZ configurations.

For the Dutch BZs, different trends emerge across scenarios. In the National Transition scenario, the BZ configuration leads to an increase in imports for NL-S. This is mainly explained by NL-N exporting more surplus production to Germany and NL-S compared to the base case.

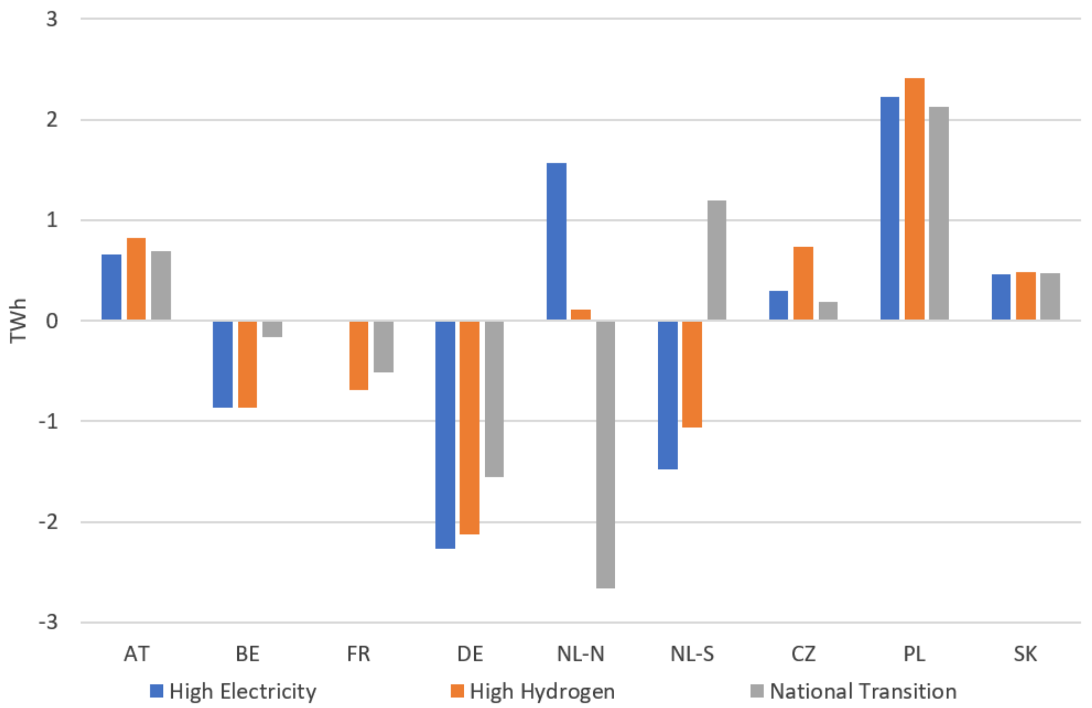


Figure 4.31: Changes in electricity generation in CORE countries due to NL2 BZ configuration

Electricity prices
Figure 4.32-Figure 4.34 show the differences in average electricity prices between the BZ case and the base case for all scenarios. The main effect is that the NL2 BZ configuration allows for more cross-border trade and thus more imports, reducing average electricity prices for Eastern European countries such as Poland, Slovakia, and the Czech Republic in all scenarios. In contrast, Western European countries, notably those with significant levels of VRE and low marginal cost generation units (e.g. Germany, France), experience an increase in electricity prices due to more exports. As a result, price convergence between Western and Eastern European countries is achieved to a higher extent.

Average electricity prices increase for the Nordic countries and the UK in all scenarios. This is explained by higher exports to Continental Europe, where electricity prices are rising, and therefore an increase in domestic generation, notably in Sweden and UK, mainly through lower wind curtailment and nuclear production.

Likewise previously analysed BZ configurations, electricity prices in most countries are highest in the National Transition scenario and lowest in the High Hydrogen scenario, with High Electricity in between. Overall, the impact of the NL2 configuration on electricity prices is minor, with variations ranging from 0.2 to 2 €/MWh.

In the Netherlands, prices increase both in NL-N and NL-S, except for the High Electricity scenario with a price decrease in NL-N. This scenario is characterized by a reduction in exports from NL-N, particularly to NL-S, with approximately 2 TWh. The decrease in imports from the North, along with a reduction in imports from Germany, leads to higher prices in NL-S, despite additional imports from the UK. The price increase in NL-N in the National Transition scenario results from the higher exports to Germany, given the higher exports of Germany to Poland, Czech Republic, and Austria.

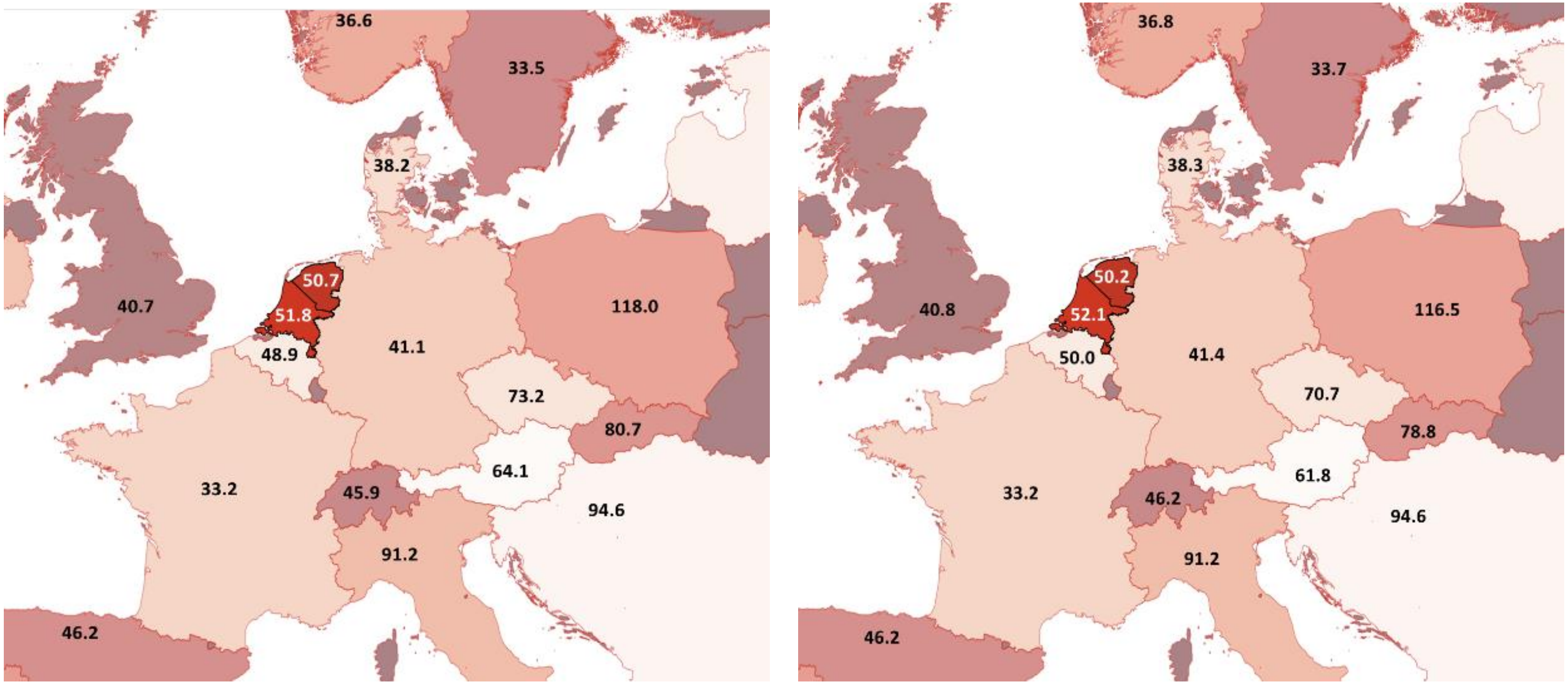


Figure 4.32: Average electricity prices in €/MWh in High Electricity scenario (left: base case, right: BZ case)

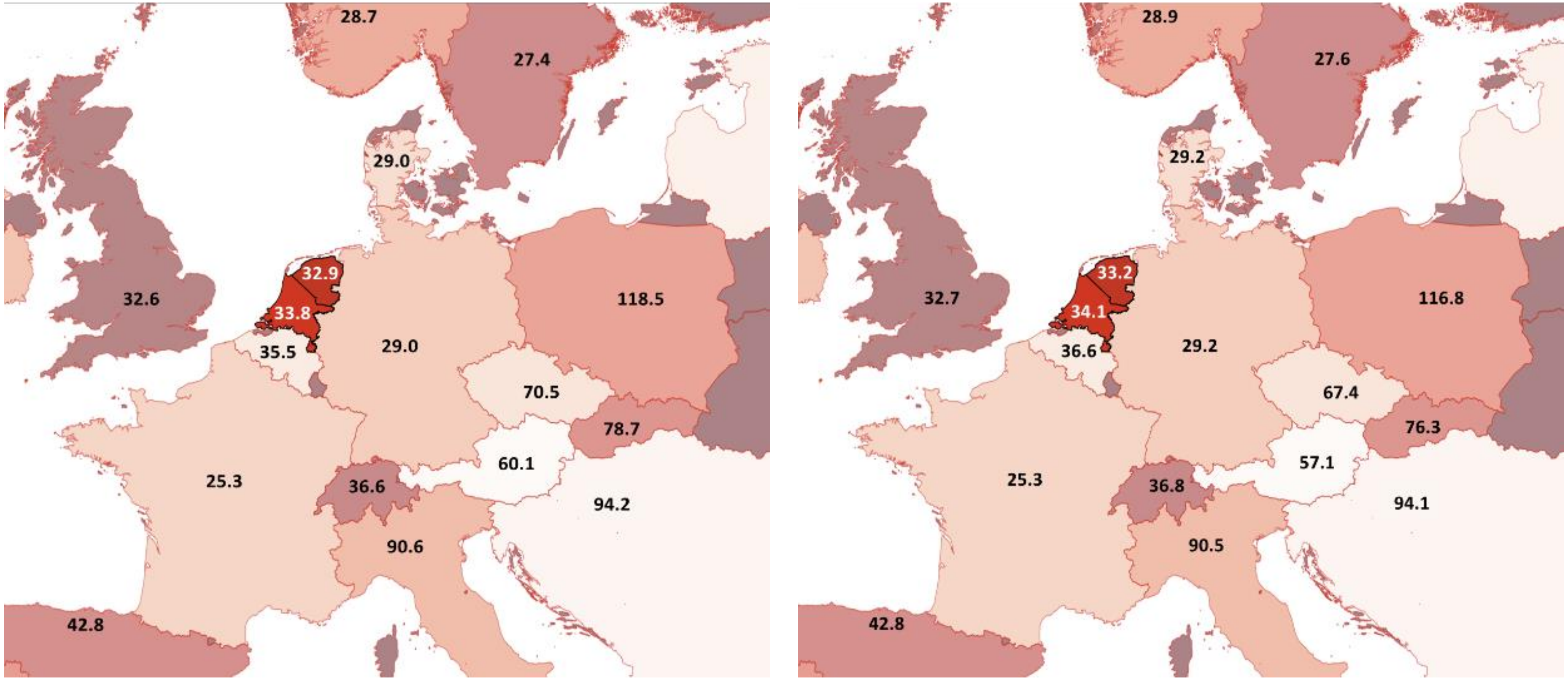


Figure 4.33: Average electricity prices in €/MWh in High Hydrogen scenario (left: base case, right: BZ case)

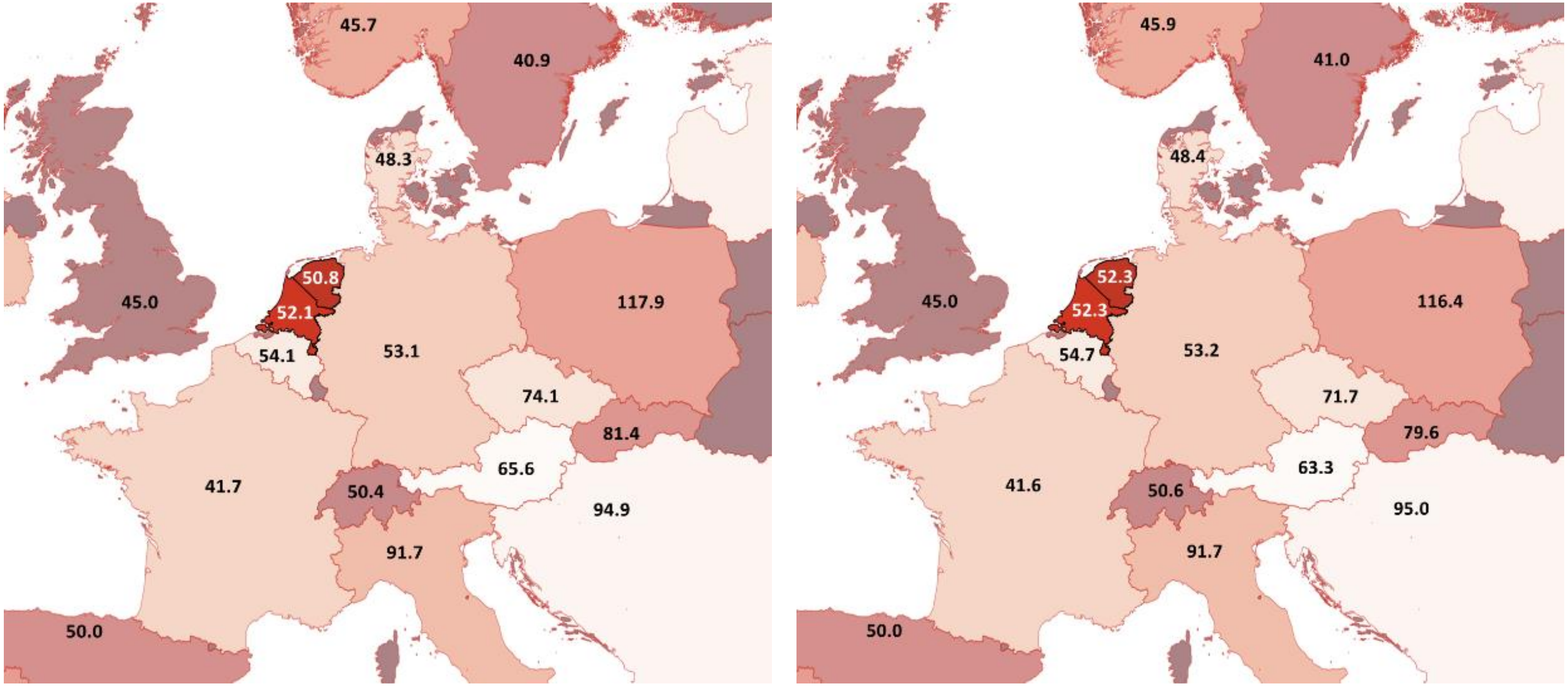


Figure 4.34: Average electricity prices in €/MWh in National Transition scenario (left: base case, right: BZ case)

4.4.2 CO_2 emissions

Table 4.5 summarizes the total CO_2 emissions of the EU-27+ power system across different scenarios and cases. The implementation of the NL2 BZ configuration clearly reduces the CO_2 emissions of the European electricity system, although reductions are limited to less than 1 Mton across the different scenarios.

Table 4.5: Total CO_2 emissions of the EU-27+ power system

[in Mton]	Country case	Base case	BZ case
High Electricity	16.9	16.9	16.5
High Hydrogen	13.7	13.8	13.2
National Transition	19.0	19.0	18.6

Figure 4.35 shows the changes of the CO_2 emissions of the electricity sector due to the NL2 BZ configuration. For most countries, the alternative BZ configuration has a negligible impact on power system emissions, especially once compared to other BZ configurations. Poland once again exhibits the most significant reduction in CO_2 emissions, with decreases exceeding 0.5 Mton in the High Hydrogen scenario.

In contrast, power sector emissions of Czech Republic increase across all scenarios with about 0.1-0.2 Mton. This slight increase can be attributed to the higher deployment of natural gas-fired power plants due to their lower deployment costs than coal-fired power plants. Hence, generators in the Czech Republic ramp up their production to export electricity to Poland during peak hours, replacing electricity from more polluting coal-fired plants in Poland.

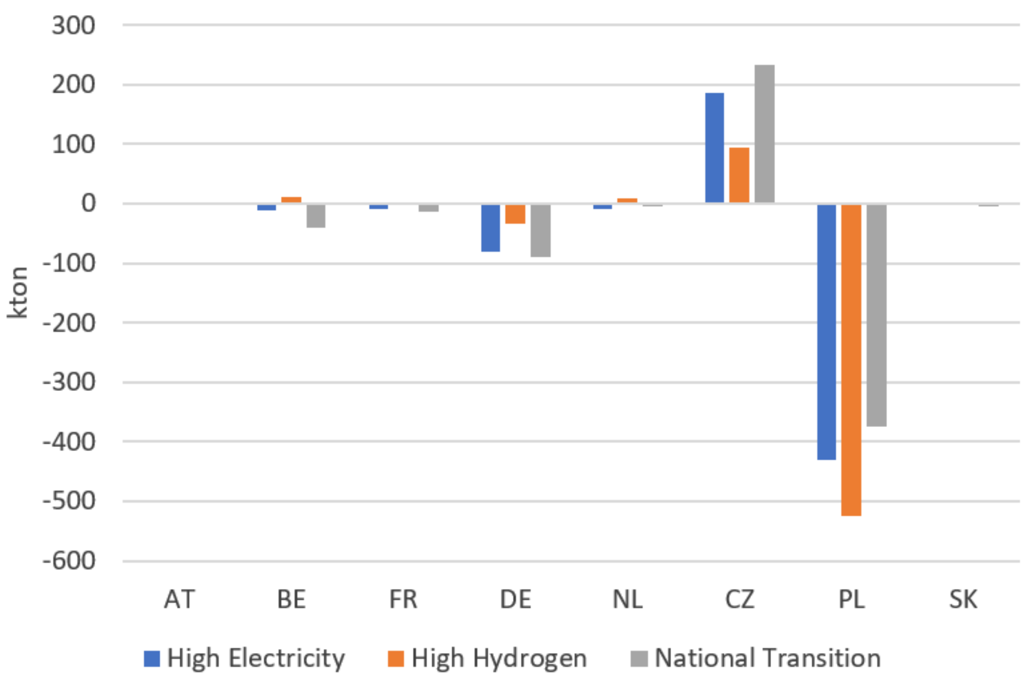


Figure 4.35: Changes in CO_2 emissions of the CORE countries due to NL2 BZ configuration

5 Conclusions and suggestions for further research

Net SEW gains of alternative German BZ configurations are significant and robust
Figure 5.1 shows that the two alternative bidding zone configurations for Germany, with Germany divided in two (DE2) and four bidding zones (DE4) respectively, deliver significant yearly socio-economic welfare gains for EU-27+ for each of the three scenarios in year 2035. Incremental socio-economic welfare changes are the sum of changes in producer surplus, consumer surplus, and congestion rents. These SEW gains have been calculated with the COMPETES-TNO market model. Generally, producer surplus decreases, while consumer surplus and congestion rents increase.

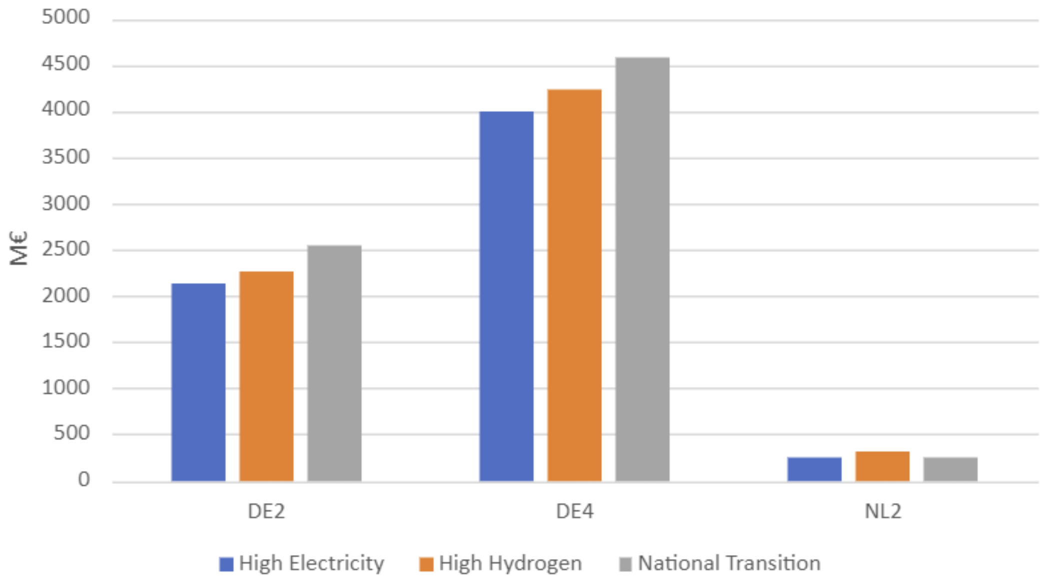


Figure 5.1: Incremental SEW effects of analysed BZ configurations for EU-27+ in 2035

The net social welfare gains result from more efficient use of the electricity network due to better integration of grid constraints in electricity markets with bidding zones. This means that part of the transactions that cause internal flows within Germany as well as loop flows through surrounding countries become subject to capacity limits during electricity trading. These restrictions within Germany relieve network capacity on the cross-zonal lines with neighbouring countries and result in an overall increase of available network capacity for the electricity market.[24] Total available interconnection capacity increases by 5.6 GW and 6.7 GW in the DE2 and DE4 configuration respectively, which is about 14-17% of the total available interconnection capacity before the bidding zone splits. The relative increases of available capacity for cross-zonal trade for these BZ configurations are quite similar to the

[24] For stakeholders with either a technical or modelling background, notably those involved in flow-based market coupling, the following reasoning could be more clear. Formerly intra-zonal constraints between German regions are incorporated in wholesale electricity pricing, allowing for an additional degree of freedom in market optimization and therefore more efficient utilization of cross-border capacities.

increases reported by ACER (2022), supporting the validity of our results. The capacity increases concern mainly interconnections of Germany with neighbouring countries, especially with the Netherlands, Poland, Czech Republic, and Belgium, and to a lower extent with Austria and Slovakia. As a result, excesses of cheap electricity production can be more easily sold to other countries, while shortages of generation can be fulfilled with electricity from abroad against lower costs. Consequently, costs for the operation of the power system decrease compared to the base case that include redispatch costs. Note that the increase of dispatch costs i.e. less optimal dispatch of power plants due to more network constraints is already accounted for in the base case which reflects the status quo situation and thus is not part of the incremental SEW effects shown here.

Given the net positive SEW effect in each scenario, the alternative German bidding zone configurations are robust for a wide range of future developments as summarized in the three decarbonisation scenarios for 2035. This includes futures which are characterised by larger roles for electricity and hydrogen in fulfilling demand, lower and higher shares of variable RES and nuclear generation, and varying deployment of flexible demand technologies such as power-to-heat, heat pumps, and electric vehicles. The SEW net benefits of alternative BZ configurations are likely to be higher for decarbonisation scenarios in 2035 compared to the current electricity system for three reasons. First, given the combination of large variation in country-specific developments until target year 2035 and significant fuel and CO_2 prices, price differences between Western and Eastern European Member States are significant, increasing benefits of additional available interconnection capacity. Second, higher shares of variable renewable energy (VRE), which tend to be located further away from load centres, result in larger electricity flows over longer distances, increasing the need for electricity transport. Hence, additional available interconnection capacity from alternative BZ configurations is likely to show higher benefits in 2035 than today. Third, the increasing role of Power-to-Heat and Power-to-Hydrogen towards 2035, implies a larger deployment of conversion options once average electricity prices decrease due to more available interconnection capacity. This volume effect enlarges the incremental SEW effect substantially.

Net SEW gains of alternative BZ configuration in the Netherlands are limited but robust
It is also visible from Figure 5.1 that the social welfare gains for EU-27+ of the alternative bidding zone configuration for the Netherlands, with the Netherlands divided in two bidding zones (NL2) are significant though considerably smaller than for the alternative BZ configurations for Germany (DE2 and DE4). Again, the social welfare gain is due to the increase of available interconnection capacity for electricity trading due to better integration of grid constraints in electricity markets with bidding zones. Total available interconnection capacity increases by 1.1 GW, which is about 3% of the total available interconnection capacity before the bidding zone split. This concerns mainly interconnections of the Netherlands with Germany, and of Germany with Czech Republic, Austria, and Poland.

At the same time, the NL2 bidding zone configuration is robust for future developments, in the sense that all scenarios show significant increases of socio-economic welfare. Considering the accuracy of the SEW estimates which is in the order of € 100 million, the positive yearly social welfare effects outweigh the transition costs of the BZ split. Compass Lexecon (2023) indicates that total one-off transition costs for the NL2 BZ configuration amount to € 50 to 450 million. The assessment to which extent the positive efficiency benefits also outweigh other possible negative effects of BZs falls outside the scope of this report.

CO_2 emission reductions of alternative BZ configurations in Germany are significant and robust
Figure 5.2 shows that overall CO_2 emissions of the electricity sector decrease for EU-27+ once Germany is subdivided in smaller bidding zones. The higher available cross-border

network capacity allows for the replacement of coal- and gas-fired generation with higher CO_2 emissions, both in Poland and to a lower extent in Germany-South, by low carbon generation with lower CO_2 emissions in other countries. The CO_2 emission reduction effects are significant and robust for the three scenarios.

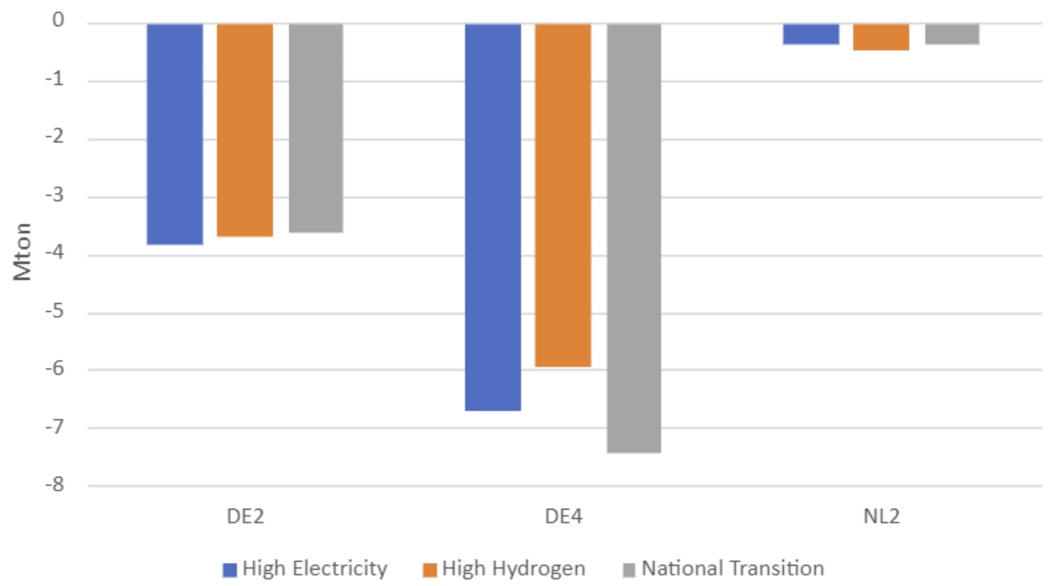


Figure 5.2: CO_2 emission reductions of analysed BZ configuration for EU-27+ in 2035

CO_2 emission reductions of the alternative BZ configuration in the Netherlands are limited and somewhat robust

Figure 5.2 shows that CO_2 emissions due to the NL2 bidding zone configuration are reduced in all scenarios, but at the same time quite limited in size. Hence, we consider the CO_2 emission reductions as somewhat robust.

SEW effects should be balanced against performance of alternative BZ configurations on other assessment criteria

It is important to be aware that the aggregated costs for adjustments of BZ configurations, so-called one-off transition costs for TSOs, DSOs, market infrastructure providers, and stakeholders in the wholesale and retail segments, are not included in the shown SEW figures. Preliminary estimates from Compass Lexecon (2023) indicate that total transition costs for German BZ configurations range from about € 1200 to 1550 million for the DE2 configuration, and from about € 1250 to 2250 million for the DE4 configuration. Total costs are mainly driven by IT system costs and internal business processes costs, and to a lesser extent costs associated with the re-negotiation or termination of contracts. Note that the mentioned ranges of estimates are one-off costs while the SEW benefits are yearly recurring.

More broadly, the analysis of other effects than social welfare, CO_2 emissions, and robustness falls outside the scope of this study. Consequently, policy makers are advised to weigh the benefits of new bidding zone configurations in terms of increased SEW and reduced CO_2 emissions against the performance of alternative bidding zone configurations on the other assessment criteria to be considered for the bidding zone review process. In total, 22 indicators are deemed relevant for the assessment of alternative BZ configurations, including criterions such as network security, market concentration and market power in wholesale markets as well as redispatching mechanisms, and price signals for building network infrastructure as well as new generation capacity.

Distribution of SEW effects over stakeholders and countries
The net SEW effects discussed before consist of larger changes in the underlying welfare components i.e. producer surplus, consumer surplus, and congestion rents. These are partially redistribution effects among producers, consumers, and TSOs. In the case of redistribution effects, the advantage for one stakeholder or country is the disadvantage for the others. Figure 5.3 shows the effects of different BZ configurations and scenarios on the SEW components. Subsequently, these effects are discussed per BZ configuration.

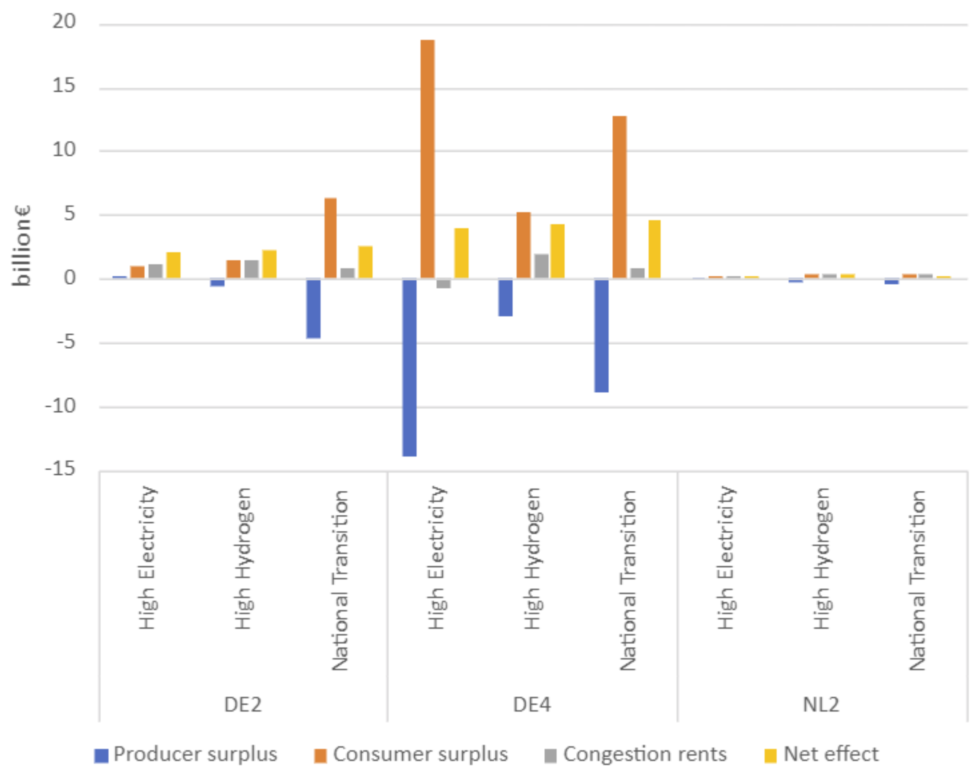


Figure 5.3: SEW components of analysed bidding zone configurations for EU-27+ in 2035

DE2 BZ configuration: SEW distribution over stakeholders and countries is largely robust
In the High Hydrogen and National Transition scenarios, producers face significant decreases of generation profits, and therefore overall producer surplus of the DE2 BZ configuration diminishes significantly compared to the base case. More bidding zones induce higher available interconnection capacity and with that more electricity exchanges among countries as well as lower wholesale electricity prices. Both the volume effect of more available interconnection capacity as well as the price effect due to increasing competition among generators tend to decrease the producer surplus. In the National Transition scenario, the overall producer surplus decrease is larger than in the other scenarios, due to significantly lower electricity prices in Germany South and Switzerland as well as decreasing exports from France to Germany South due to less nuclear generation. The lower electricity prices can be explained by the constrained situation in Germany South in the base case, which is greatly mitigated by increased opportunities for exchange with neighbouring countries in the project alternative. In the High Electricity and High Hydrogen scenarios, the lower producer surplus in Germany South, Poland, Austria, and Czech Republic, is at least partially compensated by significantly higher producer surplus in Germany North and the Nordic countries. In the High Electricity scenario, this means that the increase of producer surplus in the latter countries outweighs the decrease of producer surplus in other CORE countries, resulting in a net producer surplus of € 100 million.

Consumers benefit from increases of consumer surplus due to lower electricity prices, notably in bidding zones located at the Southern side of the German North-South BZ border but also in Poland. The price effect is exacerbated by the volume effect of increasing electricity consumption of flexible demand. Again, the net change of surplus is larger in the National Transition than in the High Electricity and High Hydrogen scenarios. This is mainly caused by the significantly larger price effect in National Transition compared to other scenarios, notably lower prices in Germany South which increase its consumer surplus by about € 4.6 billion compared to about € 700 and € 950 million in High Electricity and High Hydrogen scenarios, respectively. Given that the deployment of flexible demand is about 150 TWh higher in High Electricity than in National Transition, the price effect clearly outweighs the volume effect for the latter scenario. At the same time, decreases of producer surplus and increases of consumer surplus cancel out each other more in National Transition than in the other scenarios.

TSOs earn more congestion rents in nearly all CORE countries mainly due to smaller price differences between countries as well as somewhat more electricity trading. This lowers ceteris paribus the electricity network tariffs for consumers in most countries. The largest positive effects on congestion rents are visible in Germany North, Germany South, Poland, and Czech Republic. France is an exception, especially in the National Transition scenario due to significantly smaller price differences with Germany South and Switzerland. The High Hydrogen scenario shows the highest overall increase. This results from the increase of electricity trading with neighboring countries which is highest in High Hydrogen, followed by High Electricity and National Transition.

Overall, SEW figures and their distribution show that the size of SEW effects is much larger in the National Transition scenario due to the constrained situation in Germany South in the base case compared to the other scenarios. SEW effects are lowest in the High Electricity scenario as changes in producer and consumer surplus largely cancel out each other. The direction of SEW effects is largely consistent in all scenarios, except for the rather insignificant increase of producer surplus in the High Electricity scenario. Hence, the SEW distribution over stakeholders and countries can be considered as largely robust.

DE4 BZ configuration: SEW distribution over stakeholders and countries is largely robust
Likewise the DE2 configuration, producer surplus decreases across the three scenarios when comparing the BZ case against the base case at CORE and EU-27+ level. These decreases result from lower electricity prices in the majority of the CORE countries due to higher cross-border trade with additional German BZs. However, producers in the Northern German BZs (DE-NW and DE-NE) as well as France benefit from increases in profits due to higher production and exports and consequently higher electricity prices. Outside the CORE region, a more diverse trend in producer surplus is visible, with producers in the Nordics usually also benefiting from more exports and higher electricity prices.

Consumer surplus increases in all scenarios, both at CORE and EU-27+ level. This total increase is always higher than the total decrease of producer surplus in the scenarios, given the increase of flexible demand due to lower electricity prices. Hence this SEW component is the main driver of the net SEW increase. As can be observed in Figure 5.3, consumer surplus is highest under High Electricity, followed by National Transition and lastly by High Hydrogen. This is explained by large price changes in the UK and the Netherlands in High Electricity, while the increase of flexible demand (‘conversion options’) is smaller than in the other scenarios. This could relate to the fact that High Electricity presents the highest electricity demand at EU-27+ level, reducing the scope for further increase of demand.

In the High Electricity scenario, the Netherlands is among the countries mostly affected by more available interconnection capacity due to bidding zones. In the base case, Dutch demand surpasses generation, resulting in a very high average electricity price, and sometimes even involuntary demand curtailment. With more available interconnection capacity, higher imports result in diminishing electricity prices and a large increase in consumer surplus. The UK shows even a larger increase in consumer surplus, resulting from less exports to Continental Europe. The consumer surplus of both countries explains about two-third of the total increase of consumer surplus in High Electricity. In the other scenarios, the Southern German BZs (DE-W and DE-S), and other CORE countries, such as Belgium and Poland show higher imports, driving down electricity prices and boosting consumer surplus.

Overall congestion rents increase for the CORE region in all scenarios, with largest effect seen in Austria, Poland, Slovakia, and Czech Republic. Again, the higher available interconnection capacity, notably between West and East Europe, leads to convergence of electricity prices across Continental Europe. The High Electricity scenario is an exception at EU-27+ level though, with a decrease of congestion income of about € 700 million compared to the base case. The main driver of this difference is the UK. In all scenarios, congestion rents in the UK are reduced, but mainly in High Electricity. The UK exports to Continental Europe through Netherlands, Belgium and France, but once more interconnection capacity becomes available, the Netherlands replaces imports from the UK by imports from other bidding zones, notably from Germany Northwest.

Overall, the changes of SEW components are lowest in High Hydrogen, driven by its lower electricity demand compared to the other scenarios. High Electricity exhibits the highest producer surplus increase and consumer surplus decrease, but the reduction in congestion rents reduces the net SEW effect. Hence, the net SEW is highest in the National Transition scenario. Despite these distribution effects, the DE4 BZ configuration can be considered as robust in terms of the direction and size of the total SEW effect. The distribution of SEW among the different stakeholders of the CORE countries is also largely robust, as we see similar trends in the SEW components for these countries, except for the development of congestion rents in the High Electricity scenario.

NL2 BZ configuration: SEW distribution over stakeholders and countries is largely robust
Producer surplus decreases across the three scenarios when comparing the project alternative against the base case at EU-27+ level, as is the case in the other BZ configurations. Because of increased cross-border trade, generators face lower electricity prices in countries with a more expensive generation mix, particularly in some Eastern European countries that are still dependent on fossil fuels with associated CO_2 emission costs under the scenarios in 2035. Notably Poland, the Czech Republic, Slovakia, and Austria benefit from higher exports from countries that are characterized by a high VRE share such as Germany. This decrease in producer surplus is partially reduced by producer surplus gains in other regions, such as the UK and the Nordics, whose producer surplus increases across all scenarios compared to the base case.

The overall decrease of producer surplus is largely counterbalanced by a corresponding increase of consumer surplus in the three scenarios, both at CORE region and EU-27+ level. This increase is driven by enhanced cross-border trade facilitated by the NL2 BZ configuration, which results in lower wholesale electricity prices for consumers in several countries.

Congestion rents rise across all scenarios, with the most significant effects in Germany and Eastern European countries. The generation mix and related price differences between those countries, together with larger cross-border capacities, create favorable conditions for cross-zonal trade, thereby increasing congestion rents. The opposite effects of consumer and producer surpluses imply that the increase of congestion rents is the main contributor to the net social welfare gains observed in the NL2 BZ configuration, with the High Hydrogen scenario showing the largest SEW increase.

Overall, the SEW effects of the NL2 BZ configuration show the same direction and size in different scenarios, and consequently can be considered as robust. The size of the effects is relatively small compared to the DE2 and DE4 BZ configurations but significant.

Limitations of the study
Study limitations are subdivided in limitations related to scenario assumptions, network reduction method, and the COMPETES-TNO electricity market model.

Scenario assumptions

- Since the generation and demand scenarios are a combination of national scenarios, they are not inherently consistent in some respects, for instance the application of different fuel and CO_2 price assumptions as well as assumptions concerning imports from neighbouring countries. This is most applicable to the National Transition scenario which is based upon diverging National Energy and Climate Plan (NECPs) of EU Member States. Therefore, the results for this scenario could be less relevant for the assessment of the robustness of the BZ configurations.
- One set of fuel and CO_2 prices was deployed for all scenarios. Another set of fuel and CO_2 prices could have an effect on both SEW results and CO_2 emissions as it might limit electricity price differences between Western Europe with high shares of low marginal cost generation (VRE and nuclear) and Eastern Europe with higher shares of high marginal cost generation (coal- and natural gas-fired generation). Consequently, generation dispatch might change and therefore CO_2 emissions.

Network reduction method

- The NR method constructs an equivalent reduced network that is closest to the real network but irrespective of where the added value of network capacity is highest. Herein we deviate from the flow-based market coupling method (FBMC) which offers flow-based capacity domains that allow for 'shifting' of available network capacities across zonal borders in case this improves social welfare. Nevertheless, we observe that the NR method makes additional grid capacity predominantly available on West-East interconnections which helps to reduce the most significant price differences between western and eastern European Member States. As such, the NR method seems to deliver results that are in line with the application of the FBMC approach.
- The NR method does not allow for testing the contribution of bidding zones to the 70% requirement concerning the availability of network capacity for cross-zonal trading, since identification of non-scheduled flows (internal flows, loop flows) requires more granular network information, e.g., flows between two particular substations, than is offered by the reduced network representation. An alternative nodal model set-up requires nodal data of generation and demand, but given the lack of access to the nodal dataset from ENTSO-E as well as inadequate commercial and public databases this proved to be not feasible.
- The NR method delivers equivalent reduced networks that include lines between non-adjacent countries, e.g. NL-AT, with limited network capacities. These are so-called synthetic lines. Their inclusion gave rise to counterintuitive results for the NL2 configuration. To improve the comprehensibility of the results, the NR method was rerun without synthetic lines for this configuration, at the expense of a small loss of accuracy of the equivalent network compared to the real network. Next, reruns were made with the COMPETES-TNO model showing results that are better understandable. However, application of the NR method without synthetic lines for the DE2 and DE4 BZ configurations shows a significant loss of accuracy of the NR optimization process, therefore we continue to use the NR results with synthetic lines for these BZ configurations.

COMPETES-TNO model

- Assumptions are made concerning the potential for electrification of demand for heat and hydrogen, which are derived from TYNDP-2022. In reality, there exist economic and social barriers that could prevent the realization of this potential.
- The deployed variant of the COMPETES-TNO model does not include explicit modelling of hydrogen systems, notably imports and exports as well as hydrogen storage. As such, the treatment of hydrogen is simplified. Besides, differences between scenario and model assumptions result in considerable differences concerning the actual deployment of electrolysis between the scenarios and COMPETES-TNO model output.

Suggestions for further research

Given the study limitations outlined above, further research on the following aspects could be useful to further inform policy makers:

1. Investigate the robustness of results for uncertainties such as other fuel and CO_2 prices, delay in realisation of ambitious RES targets in Germany and other EU Member States, delay in HVDC network expansion projects in Germany, and lower demand electrification;
2. Scrutinize the effects of a combination of alternative BZ configurations for Germany and the Netherlands, i.e. DE2 plus NL2 and DE4 plus NL2, in addition to the current individual BZ configuration assessment;
3. Research the impacts on the Netherlands of the other alternative BZ configurations that are part of the BZ review.

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Appendix A
Generation and load assumptions

Model assumptions

In order to model the different scenarios considered for this study, several assumptions needed to be made to accommodate the scenario data to the modelling capabilities of COMPETES-TNO UC module. These assumptions concern mainly the scenario assumptions of flexible demand and the conversion technologies. The profile of heat pumps and inflexible base demand are based on the hourly profiles from the Flexnet project (Sijm et. al., 2017a) for the climate year 2015, as well as the VRE profiles. This profile can be modified by the model according to the electricity prices as heat pumps are modelled as load-shifting technologies. Key modelling assumptions for each scenario are described below.

NEP23

The German scenarios consider several electricity demand figures according to the different sectors (i.e. mobility, residential, industry, etc.). For the residential sector, the NEP scenarios provide a specific demand for heat pumps and for district heating. This demand figures are combined and considered as a direct input for our model simulations.

For the modelling of EVs, the NEP scenarios provide a specific demand figure for electric and plug-in personal vehicles, in which we base for our modelling purposes. Similar to the heat pumps, the EVs have a demand profile that can be shifted according to the optimization of the model.

For Power-to-Heat assumptions, the NEP23 includes information for the district heating (Fernwärme) sector. However, no specific information regarding industrial Power-to-Heat was found. The NEP23 states that for the market modelling simulation "*Certain industrial applications are modelled as processes that can be switched off*" (NEP, translated). That is, industrial Power-to-Heat. Usually, the electrification of industrial heat occurs for what is considered low-temperature processes (below 500 degrees Celsius). These processes have the potential to be supplied by e-boilers or similar Power-to-Heat technologies. In order to estimate these heat processes from the industrial demand given in the NEP, we use the TYNDP-22 demand data to find the share of electrified heat processes and compare it to the total industry demand. This results in an estimation that 75% of the total final electric industrial demand correspond to industrial heat processes. We applied this share to the industrial demand reported in the NEP to obtain an estimation for industrial Power-to-Heat.

For Power-to-Hydrogen, a hydrogen demand of 122.5 TWh is assumed (FNB Gas, 2023). The final electricity demand from Power-to-Hydrogen depends on the optimization of the electricity prices and the assumed installed capacities of electrolysers in the scenarios. In the COMPETES-TNO version used for this study, the H_2 system representation is limited to this load-shedding capability of electrolysers. The operation of electrolysers is determined by their opportunity costs i.e. the marginal costs of H_2 production with Steam Methane Reform (SMR) technology. When electricity prices are below the opportunity costs, the electrolysers will start operating. Vice versa, if electricity prices are higher than opportunity costs, then electrolysers would switch off, and H_2 will be supplied through SMRs. The H_2 marginal production cost is determined by the fuel (i.e. natural gas) and CO_2 prices. Given the assumptions regarding these parameters, the marginal cost is set at 90 €$_{2023}$/MWh.

IP2024

The Dutch national scenarios provide final electricity demand figures for the different flexibility sectors (Netbeheer Nederland, 2023), and we use these figures as input for the model. Contrary to the NEP23, the IP2024 provide specific figure assumptions regarding industrial Power-to-Heat. This mainly refer to the installed capacity of the e-boilers and their final electricity demand for each scenario. We take the potential yearly demand of the given installed e-boilers and introduce them as input for the maximum potential demand of industrial Power-to-Heat, which its final demand would be determined by the optimization process.

For Power-to-Hydrogen, the H_2 demand serves as input to the model and we optimize the H_2 supply through either electrolysis or SMRs according to the installed capacities of electrolysis and the electricity prices.

TYNDP-22

For the European scenarios, final demand figures for different sectors are reported. We identify the different flexible sectoral demand figures for EVs and all-electric heat pumps for the mobility and residential sector respectively. Following the same approach as in the German scenarios, the electricity demand resulting from industrial heat processes is taken as the maximum potential that can be provided by Power-to-Heat.

The results of the final electricity demand were aligned as much as possible with the national and European scenarios final demand figures. However, divergences due to the market modelling assumptions are inevitable.

For the other modelled countries, the same approach as France (TYNDP-22 scenario approach) is followed. The resulting demand and generation figures for these countries are presented below:

Table A.1: Installed capacities input for additional modelled regions in COMPETES-TNO

Inst. Cap. [GW]	AT	BE	BK	BT	CH	CZ	DK	ES	FI	IE	IT	NO	PL	PT	SE	SK	UK
Solar PV	30	16	40	2	24	10	9	77	4	2	64	0	10	11	15	1	45
Wind Onshore	16	7	27	3	1	1	5	57	20	6	21	5	7	13	18	0	40
Wind Offshore	0	6	0	3	0	0	12	1	5	5	4	0	10	1	17	0	57
Natural gas	0	9	18	1	0	4	1	24	1	4	40	0	11	3	0	1	20
Hydrogen to power	1	1	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0
Other RES	1	1	3	1	1	1	0	2	3	0	5	0	2	1	5	0	10
Hydro PS	8	1	4	1	15	1	0	11	0	0	12	33	2	4	0	1	3

Inst. Cap. [GW]	AT	BE	BK	BT	CH	CZ	DK	ES	FI	IE	IT	NO	PL	PT	SE	SK	UK
Nuclear	0	0	10	0	0	5	0	0	5	0	0	0	4	0	5	3	11
Other non-RES	0	2	12	0	1	1	1	4	2	0	6	0	14	1	0	1	11
Biomass	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0
Batteries	2	1	1	0	1	2	0	7	1	1	2	0	0	0	1	0	17
Hydro	9	0	27	2	4	1	0	15	3	0	17	0	1	5	16	2	2

Table A.2: Electricity and hydrogen demand inputs for additional modelled regions in COMPETES-TNO

E-Demand and DR	AT	BE	BK	BT	CH	CZ	DK	ES	FI	IE	IT	NO	PL	PT	SE	SK	UK
Inflexible demand [TWh]	50	47	222	21	62	38	44	0	161	269	28	0	162	116	38	80	17
EVs [peak dem. GW]	5.1	5.9	24.3	3.4	11.8	4.4	5.5	23.0	4.7	3.3	32.3	8.8	14	7.0	8.4	2.5	62.1
Heat Pumps [peak dem. GW]	10	11	24	3	0	5	4	22	14	4	33	0	15	4	22	3	56
Power-to-Heat [GW]	3	4	9	1	0	3	1	0	7	16	1	0	0	6	2	5	1
Power-to-Hydrogen [GW]	1.2	2.2	9.8	1.3	0.0	1.2	15.0	14.6	12.4	4.6	6.9	0.0	5.3	5.7	4.7	0.6	5.2
Hydrogen demand	AT	BE	BK	BT	CH	CZ	DK	ES	FI	IE	IT	NO	PL	PT	SE	SK	UK
[TWh]	25.8	61.5	43.3	0	0	27.1	8.3	52.2	15.2	1.7	37.2	0	0	0	34	1.2	40

Generation and load distribution for new bidding zones

The generation and load distribution for the BZ configurations for Germany and the Netherlands is based upon multiple sources. The distribution figures for the BZ configurations for Germany and the Netherlands were obtained from the BZR. For confidentiality reasons these figures are not reported here, but as part of the upcoming ENTSO-E BZR study. Since these figures reflect the current situation, some figures were updated to account for envisaged developments until 2035 once more information was available.

In the case of Germany, the NEP23 provides figures at regional level for installed capacities and demand, including those concerning DR such as EVs, Power-to-Hydrogen and residential Power-to-Heat. Regional figures for 2037 were used to distribute the domestic load and generation capacities. Additionally, we distinguished between efficiencies of different categories of gas-fired German power plants based upon the Kraftwerksliste (BNetzA, 2024). In the NEP23 scenarios, total installed gas-fired capacity amounts to 38.4 GW in 2037 but no clear distinction is made between the capacities of natural gas-fired and hydrogen-fired power plants. In order to make that distinction, based upon the DE scenario from TYNDP-22 we assume 9.7 GW of hydrogen-fired power plants, leaving 28.7 GW of natural gas-fired plants.

In its latest Kraftwerksstrategie, the German government announced a 12.5 GW tender for new build gas capacities, from which 5 GW will be “hydrogen-ready” plants, so running with natural gas for 8 years and then switching to H_2, 2 GW of existing NG plants to be retrofitted into H_2, and an additional 5 GW of new built H_2 plants (BMWK, 2024). The distribution of these new capacity is forecasted to be mainly located in the South of Germany to handle net congestion. Given that the new built capacity will be prioritized in Germany South and the retrofit of the 2 GW plants is distributed between North and South, our best guess is that approximately 10% of H_2-fired plants would be located in the North and the rest in the South.

For the Netherlands, the IP2024 scenarios does not include regionalized figures like the German NEP23. Therefore, an effort was made to distribute the different demand and generation capacities for the NL2 BZ configuration. For the inflexible base demand and installed generation capacities of key technologies, we used the distribution data reflecting the current situation, with some exceptions:

- For offshore wind, the distribution over the Northern and Southern BZ of the Netherlands is derived from Witteveen+Bos (2022). We assume that in all scenarios 7.33 GW will be connected to the Northern part of the Netherlands. This is equal to the installed offshore wind power capacity in the North of the Netherlands over the Wadden in the IA scenario for 2035.
- The EV's distribution is based on the Elaad NL Outlook geographical spreading of EVs for the 'Midden scenario' in 2035 (ElaadNL, 2024).
- For heat pumps, the data from CBS regarding electric heating per province is used (CBS, 2024).
- Other flexible demand shares for Power-to-Heat and Power-to-Hydrogen were based on the regional database of the TNO model I-ELGAS, which includes nodal data distribution information for the Netherlands. For Power-to-Heat, the share was based on the electricity demand from industry. For Power-to-Hydrogen, the distribution share was based on the installed capacities of electrolysers.

Appendix B
Description of network reduction method

Kron reduction

The standard node equations in a power system with nb nodes can be expressed in matrix form as

$$\mathbf{I} = \mathbf{Y}_{\text{bus}}\mathbf{V} \qquad \text{(AB.1)}$$

where $\mathbf{I}$ and $\mathbf{V}$ are column matrixes (nb x 1) and $\mathbf{Y}_{\text{bus}}$ is a symmetrical square matrix (nb x nb). Matrices can be rearranged so that elements that are to be eliminated (undesired nodes u) are in the lower rows of the matrices and nodes to remain (desired nodes d) are in the upper rows so that $u + d = nb$. After this rearrangement, equation (AB.1) is expressed as

$$\begin{bmatrix}\mathbf{I_D}\\ \mathbf{I_U}\end{bmatrix} = \begin{bmatrix}\mathbf{K} & \mathbf{L}\\ \mathbf{L}^T & \mathbf{M}\end{bmatrix}\begin{bmatrix}\mathbf{V_D}\\ \mathbf{V_U}\end{bmatrix} \qquad \text{(AB.2)}$$

where $\mathbf{I_D}$ is the submatrix of currents entering the nodes to be retained and $\mathbf{V_D}$ the voltages of these nodes, both with shape (d x 1). Similarly, $\mathbf{I_U}$ is the submatrix of currents entering the nodes to be eliminated and $\mathbf{V_U}$ the voltages of these nodes, both with shape (u x 1). Notice that it is assumed that $\mathbf{I_U} = \mathbf{0}$ so the Kron reduction can be performed. Submatrix $\mathbf{K}$ (d x d) is symmetrical and represents the admittance matrix only containing nodes to be retained; while $\mathbf{M}$ (u x u) is also symmetrical but contains only nodes to be eliminated. $\mathbf{L}$ (d x u) and its transpose $\mathbf{L}^T$ (u x d) are composed of only those mutual admittances common to a node to be retained and one to be eliminated.

Notice that equation (AB.2) can be expressed algebraically as

$$\mathbf{I_D} = \mathbf{K}\mathbf{V_D} + \mathbf{L}\mathbf{V_U}. \qquad \text{(AB.3)}$$

and

$$\mathbf{I_U} = \mathbf{L}^T\mathbf{V_D} + \mathbf{M}\mathbf{V_U}. \qquad \text{(AB.4)}$$

Since $\mathbf{I_U} = \mathbf{0}$, then equation (AB.4) can be rewritten as

$$-\mathbf{M}^{-1}\mathbf{L}^T\mathbf{V_D} = \mathbf{V_U} \qquad \text{(AB.5)}$$

The expression for $\mathbf{V_U}$ substituted in equation (AB.3) gives

$$\mathbf{I_D} = \mathbf{K}\mathbf{V_D} - \mathbf{L}\mathbf{M}^{-1}\mathbf{L}^T\mathbf{V_D} \qquad \text{(AB.6)}$$

From this, it can be inferred that the admittance matrix of the **reduced network** is

$$\mathbf{Y}_{\mathbf{bus}}^{\mathbf{NR}} = \mathbf{K} - \mathbf{L}\mathbf{M}^{-1}\mathbf{L}^T \qquad \text{(AB.7)}$$

For a more detailed description and the construction of the admittance matrix, the interested reader is referred to (Grainger & Stevenson, 1994).

Total Transfer Capacities (TTCs)

Calculating TTCs is based on the DC Power Flow formulation and its equivalent representation using PTDFs as

$$\mathbf{P} = \mathbf{B_{bus}}\boldsymbol{\theta} \tag{AB.8}$$

Where $\mathbf{P}$ $(nb - 1 \text{ x } 1)$ is the nodal net power injection (generation – demand) removing the slack bus, $\mathbf{B_{bus}}$ $(nb - 1 \text{ x } nb - 1)$ is the network's susceptance matrix removing the row and column of the slack bus, and $\boldsymbol{\theta}$ $(nb - 1 \text{ x } 1)$ is the vector of voltage angles removing the slack bus. Solving for $\boldsymbol{\theta}$ allows for the calculation of an approximation of the power flowing through the network lines with respect to the slack bus.

PTDFs are linear sensitivities representing the marginal change of the active power flow on a line after a marginal increase of the power injection at a node. In formal terms, the change in the flow of line ij associated with a power injection at node m and an equivalent withdrawal at the receiving bus n is

$$\Delta P_{ij} = \mathrm{PTDF}_{ij,mn}\Delta \mathrm{P}_m \tag{AB.9}$$

where,

$$\mathrm{PTDF}_{ij,mn} = \frac{X_{im} - X_{jm} - X_{in} + X_{jn}}{x_{ij}} \tag{AB.10}$$

with, X_{im} being the entry in the ith rown and mth column of the reduced reactance matrix $\mathbf{X_{bus}} = (\mathbf{B_{bus}})^{-\mathbf{1}}$ and x_{ij} is the reactance of the line connecting nodes i and j.
In matrix form, the PTDFs can be expressed as

$$\mathbf{PTDF} = \mathbf{B_{line}}\mathbf{X_{bus}} \tag{AB.11}$$

With $\mathbf{B_{line}}$ $(nl \text{ x } nb - 1)$ being a sparse matrix of line reactances with only two non-zero elements per row, corresponding to the nodes each line connects, and nl is the number of lines. Equation (AB.11) results in the matrix $\mathbf{PTDF}$ $(nl \text{ x } nb - 1)$ representing the change of flow in each line to an injection in bus m and a withdrawal at each remaining node of the system (Chatzivasileiadis, 2018).

TTCs are obtained by injecting power in one node and subtracting it in the other until one element of the network is saturated, taking into account the electrical properties of the network (Kirchhoff laws). Now consider the transaction w_p between zones i and j, and the set of lines as L. The maximum power limit of each line is F_l where $l \in L$. Assuming symmetrical values, the TTC between these zones is

$$TTC_{ij} = \min_{l \in L}\left\{\frac{F_l}{\mathrm{PTDF}_{l,ij}}\right\} \tag{AB.12}$$

Notice that matrix $\mathbf{PTDF}$ changes with the topology of the network. Hence, there is a $\mathbf{PTDF}$ matrix for each configuration n in the N-1 criteria, $\mathbf{PTDF}^n$ and the set of lines L^n, as

$$TTC_{ij} = \min_{n \in N}\left\{\min_{l \in L^n}\left\{\frac{F_l}{\mathrm{PTDF}^n_{l,ij}}\right\}\right\} \tag{AB.13}$$

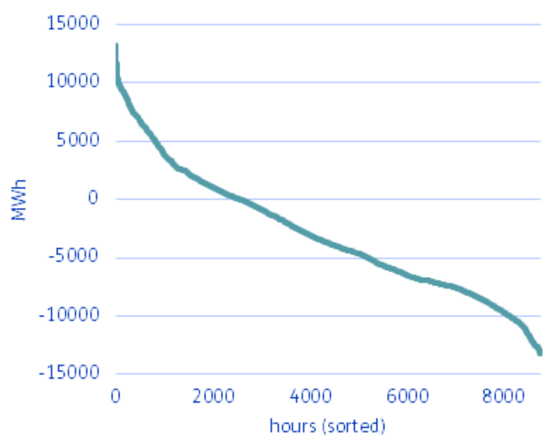
Where N is the set of contingencies in the N-1 criteria.

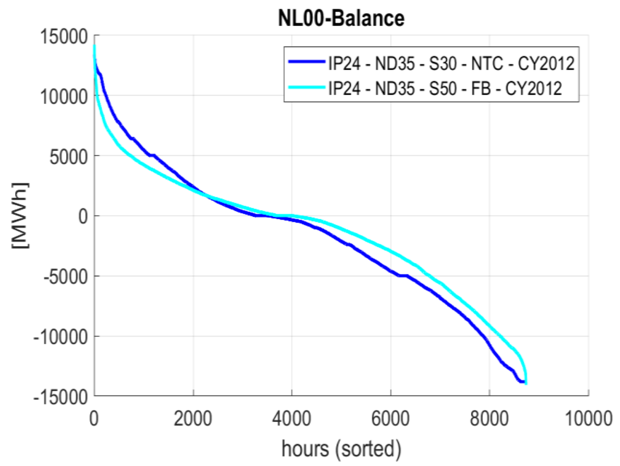
Validation of Network Reduction methodology

An exhaustive validation of the NR method was performed using IEEE test networks as well as net positions for IP2024 obtained from TenneT. COMPETES net positions for the High Electricity scenario, with network capacities and susceptances from the NR method as inputs, were contrasted against the flow-based (FB) net position duration curves from the IP2024 ND scenario for 2035 (see Figure B.1). This validation was performed considering the status quo bidding zone configurations which, with a few exceptions, consist of one zone per country. The results for France, Germany, and The Netherlands in Figure B.1 illustrate that the NR methodology delivers results in the same ballpark as the FB method.

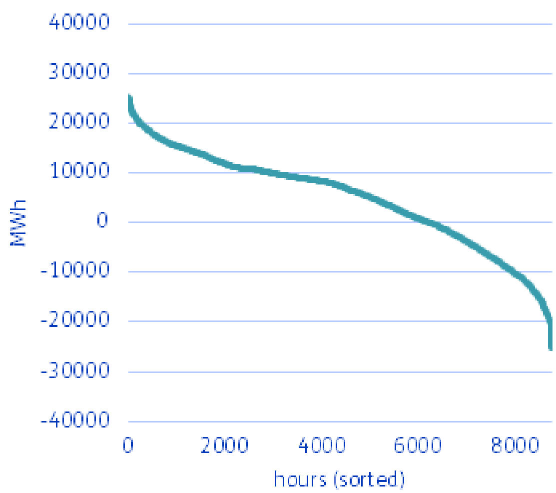
Figure B.1: Net position duration curves of NR versus FB method for the Netherlands, Germany, and France

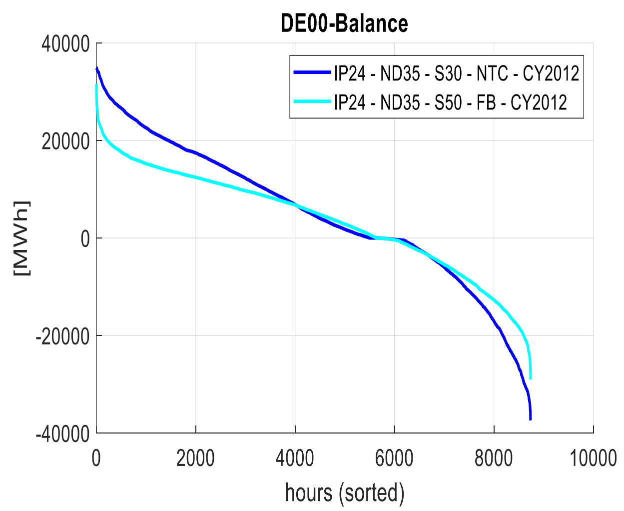
Network Reduction	Flow Based
Netherlands	



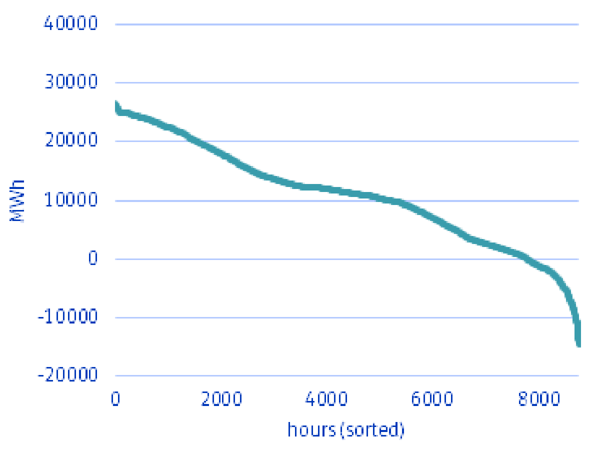


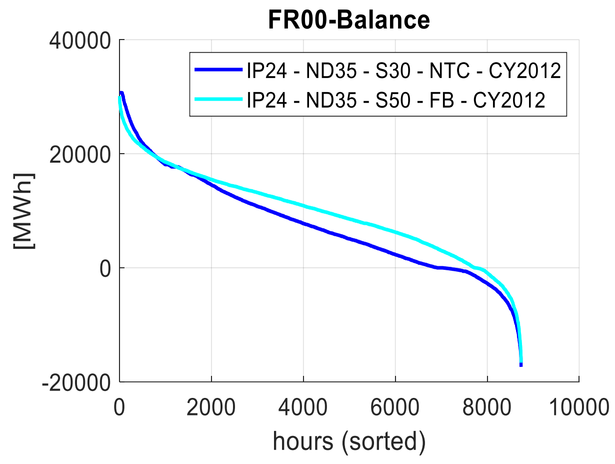
Network Reduction	Flow Based
Germany	





Network Reduction	Flow Based
France	

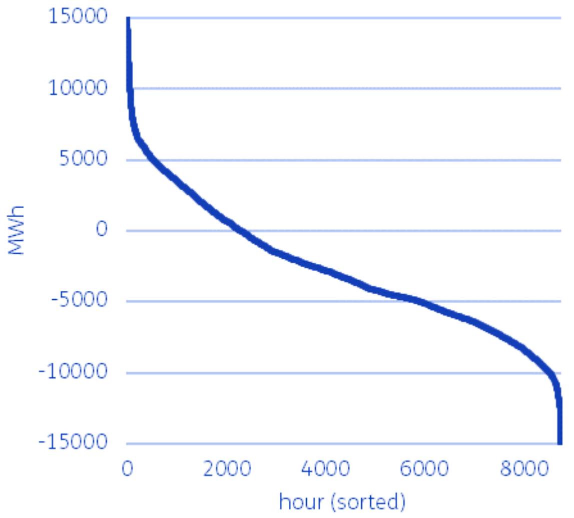


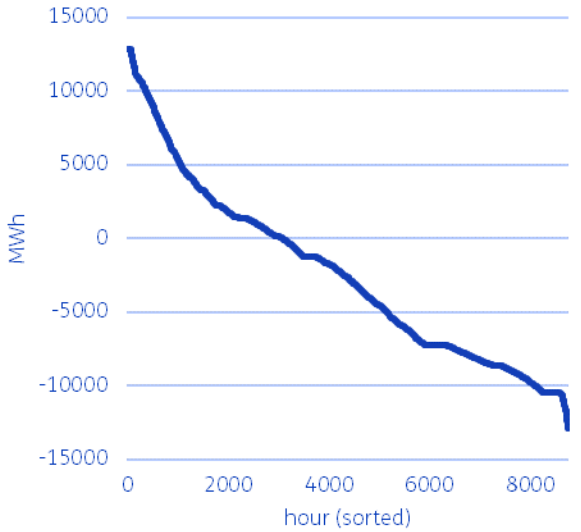


For the simulations of the NL2 BZ configuration, a NR version without synthetic lines was used. Hence, the effects of eliminating synthetic lines on net positions were tested, like before for the status quo BZ configuration with the Netherlands as on one bidding zone. Figure B.2 shows the COMPETES net position duration curves for the Netherlands under the country case in the High Electricity scenario with NR results for variants with and without synthetic lines as inputs. Although the NR version without synthetic lines allows for somewhat lower exports and imports in most extreme situations compared to the NR version with this type of lines, overall the shapes of the duration curves are rather similar.

Figure B.2: Net position duration curves for the Netherlands for variants with and without synthetic lines

NR with synthetic lines	NR without synthetic lines
Netherlands	





Transmission projects expansion network considered

In order to apply the NR method, data regarding the CORE electricity network was collected to simulate the network planned for 2035. First, JAO Static Grid Model data was gathered to construct a network model of the current situation. This data contains technical information of the transmission elements of the different CORE countries (i.e. substations, line capacities and reactances). Second, TYNDP 2022 network expansion projects that are currently either in permitting or construction phase were added to the network model.

Table b. shows which projects expansion were considered (ENTSO-E & ENTSO-G, 2022).

Table B.1: Extended list of additional TYNDP-22 network expansion projects considered

Project ID	Investment name	Technology
35	Kocin-Mirovka	AC
35	Kocin-Prestice	AC
103	Diemen-Lelystad-Ens	AC
103	Ens-Zwolle	AC
103	Krimpen-Geertruidenberg	AC
103	Eindhoven-Maasbracht	AC
187	St. Peter (AT) -Pleinting (DE)	AC
200	CZ NorthWest-South corridor	AC
230	Krajnik-Baczyna	AC
230	Mikulowa-Swiebodzice	AC
230	Baczyna-Plewiska	AC
297	BRABO II: Zandvliet - Lillo - Liefkenshoek	AC
297	BRABO III: Liefkenshoek - Mercator	AC
312	St. Peter - Tauern	AC
346	ZuidWest380NL Oost	AC
1119	Bisamberg (AT) - Wien SO (AT) - Parndorf (AT)	AC
1120	Wien SO (AT) – Ternitz (AT) – Hessenberg (AT)	AC
130	HVDC SuedOstLink	DC
132	HVDC Line A-North	DC
235	HVDC SuedLink	DC
254	HVDC Line A-South Ultranet	DC

Appendix C
Additional generation cost assumptions

Table C.2: Variable O&M and start-up costs of generation technologies.

Generation technology	Variable O&M ($€_{2023}$ / MWh)	Start-up costs ($€_{2023}$ / MWh)
Wind onshore	2.0	0
Wind offshore	3.1	0
Solar PV	1.0	0
Gas CCGT	1.9	46
Gas GT	1.9	39
Gas CHP	1.9	39
Biomass	3.9	52
Other non-RES	3.9	61
Other RES	2.3	0
Batteries	1.3	0
Hydro ROR/Conventional	1.4	0
Hydro Pumped Storage	1.6	0
Coal	3.9	69
Uranium	11	25
Oil	3.9	52
Hydrogen CCGT	1.9	46
Hydrogen CHP	1.9	39
Hydrogen GT	1.9	39

Appendix D
Additional results

The total demand and generation figures for the BZ case under the different configurations and scenarios for France, Germany and Netherlands are summarized in this Appendix, as well as the net positions of the cases and the resulting net cross-zonal flows.

Demand and generation BZ cases

DE2 configuration

Figure d.1 provides a summary of electricity demand in the BZ case for the D2 configuration, highlighting distinct differences between Germany North (DE-N) and Germany South (DE-S). In DE-N, there is a strong dominance of flexible demand, particularly from Power-to-X applications such as electrolysis and Power-to-Heat. Conversely, DE-S has a higher proportion of inflexible demand. For France, electricity demand remains largely consistent across scenarios, with electrolysis being the primary distinguishing factor. In the Netherlands, total demand is highest in the High Electricity scenario and lowest in the High Hydrogen scenario, with the National Transition scenario falling between these two extremes.

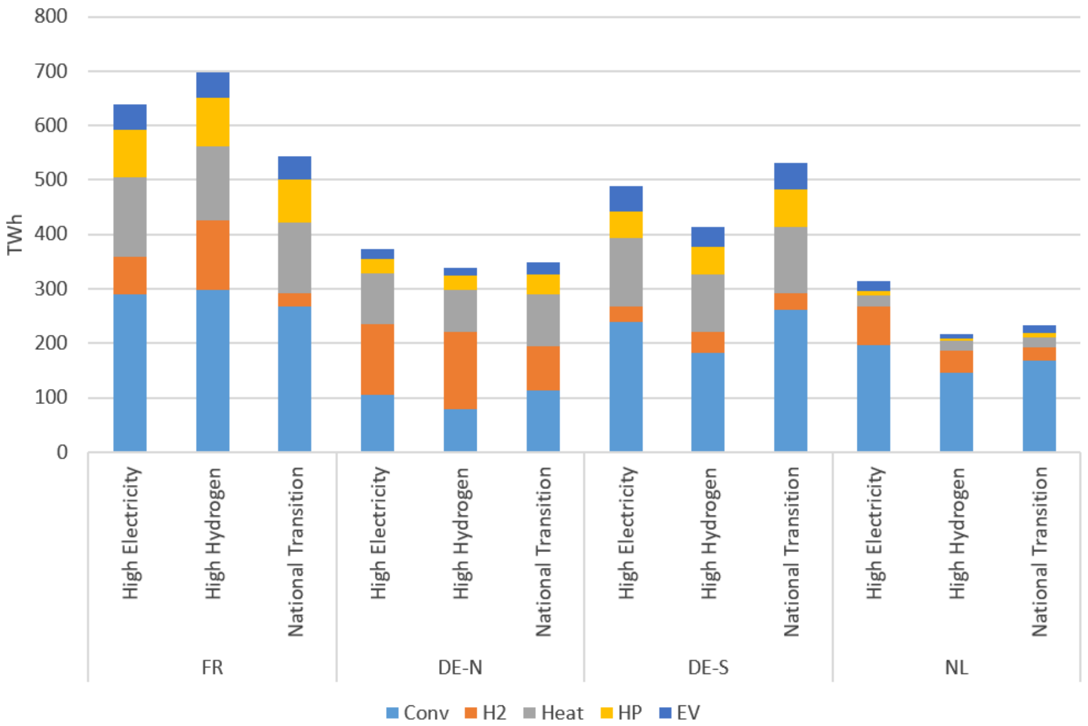


Figure D.1: Electricity demand BZ case for France, Germany and the Netherlands under the DE2 configuration

The generation mix, as illustrated in Figure d.2, reveals significant differences across scenarios. In the National Transition scenario, France has approximately 150 GW less generation capacity compared to the High Electricity and High Hydrogen scenarios. This capacity reduction leads to 230-240 TWh lower total generation, while nuclear output increases by 40-105 TWh compared to the other scenarios. For the Netherlands, the generation capacity is 25 GW lower than in the High Electricity scenario but 24 GW higher than in High Hydrogen. This capacity adjustment mainly involves a reduction in solar and wind generation. Additionally, around 2.5 GW of natural gas-fired generation replaces an equivalent capacity of hydrogen-fired generation, resulting in corresponding changes in the production of variable renewable energy sources (vRES) from wind and solar, as well as shifts in natural gas consumption.

In Germany, wind power capacity increases by 3 GW and 11 GW in comparison to the High Electricity and High Hydrogen scenarios, respectively. The expansion in vRES production is particularly notable in Germany South, while there is a slight uptick in natural gas dispatch across the country.

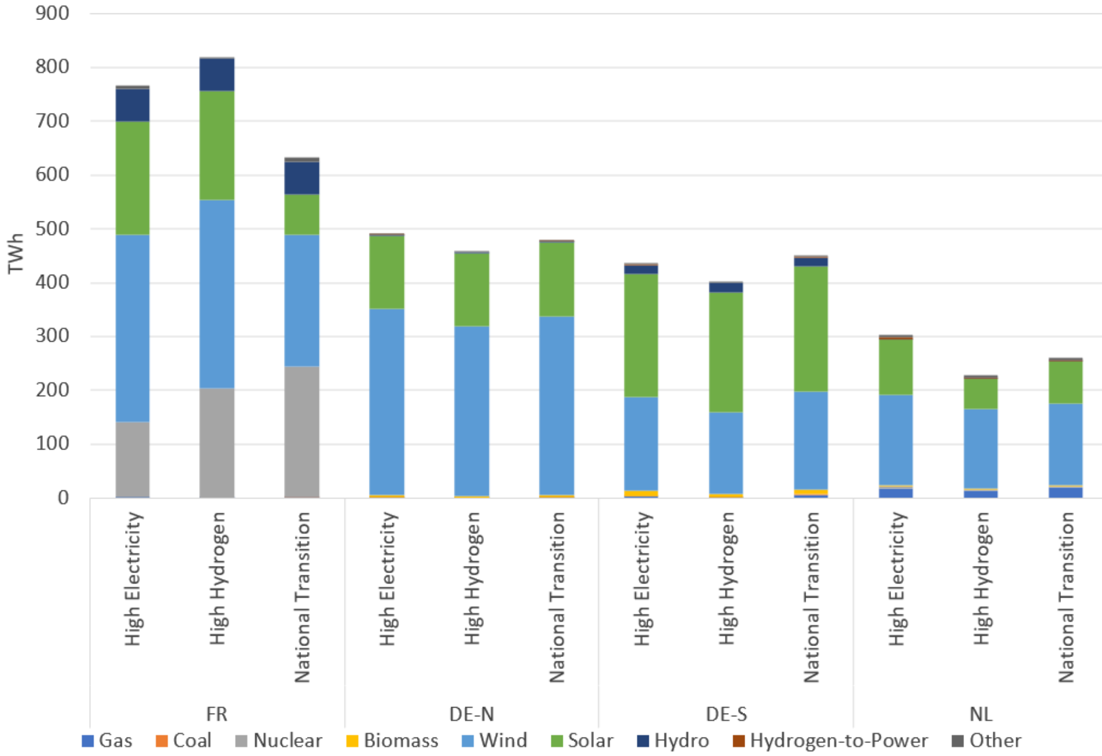


Figure D.2: Generation mix BZ case for France, Germany and the Netherlands under the DE2 configuration

DE4 configuration

The split of Germany in four BZs results in a different distribution of electricity demand. As can be seen in Figure d.3, Germany's two BZs located in the South (DE-W and DE-S) together with Germany North-East (DE-NE), exhibit the highest level of electricity consumption. Meanwhile, Germany North-West (DE-NW) presents the lowest demand across all scenarios. The Northern BZs (DE-NE and DE-NW) exhibit a high share of flexible consumption in the form of electrolysis. Southern BZs, on the other hand, show a stronger base demand, with Power-to-heat as main flexible demand category. Similar to the DE2 configuration, High Electricity presents the highest total electricity consumption at EU-27+ level, followed by High Hydrogen and National Transition.

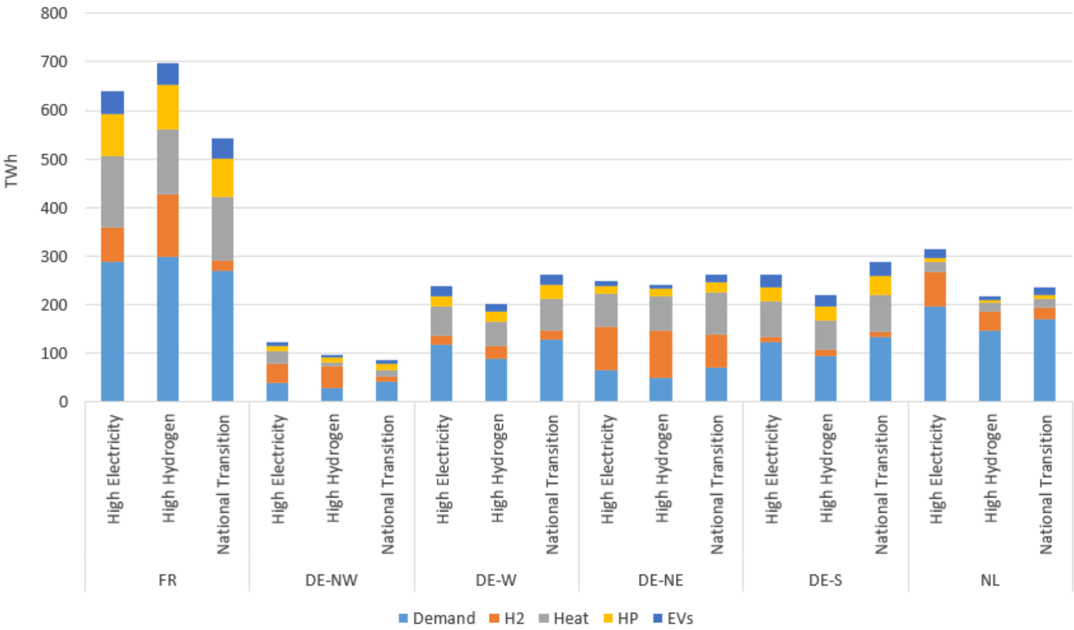


Figure D.3: Electricity demand BZ case for France, Germany and the Netherlands under the DE4 configuration

The generation mix in the BZ case follows again similar trends as in previous DE2 configuration. Figure d.4 shows the distribution of the generation mix, amongst others over the four German BZs. The German Northeast region shows the highest production, with large amounts of offshore wind production, reaching more than 300 TWh of total production in each scenario. Total generation in Southern Germany BZs (DE-W and DE-S), amounts to about 200 TWh. For Germany-South the mix shows a large share of solar PV production, followed by wind (onshore) and hydro production, with a limited contribution from gas-fired generation.

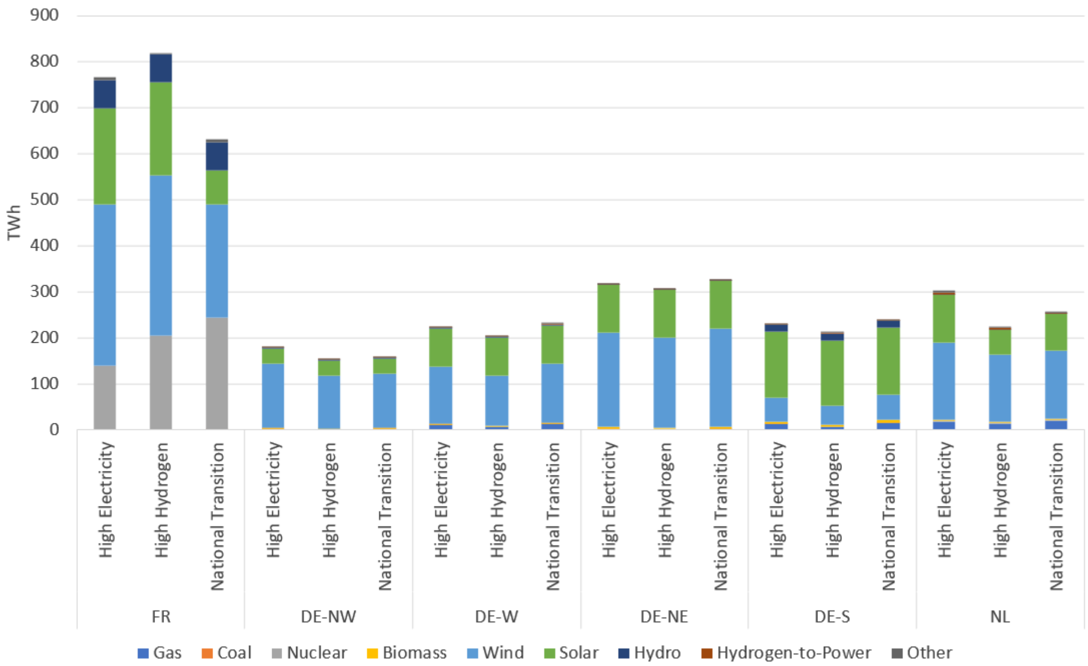


Figure D.4: Generation mix BZ case for France, Germany and the Netherlands under the DE4 configuration

NL2 configuration
Figure d.5 illustrates the overall demand and its components across the studied scenarios, highlighting differences in the share of flexible demand within the Dutch BZs. In NL-N, 50% of the total demand is inflexible, while 30% is attributed to electrolysis in both the High Electricity and High Hydrogen scenarios. The remaining demand primarily comes from load-shifting sources such as heat pumps (HP) and electric vehicles (EVs). In contrast, in NL-S conventional demand constitutes approximately 70% of total demand across scenarios, indicating a power system with lower flexibility than Netherlands North.

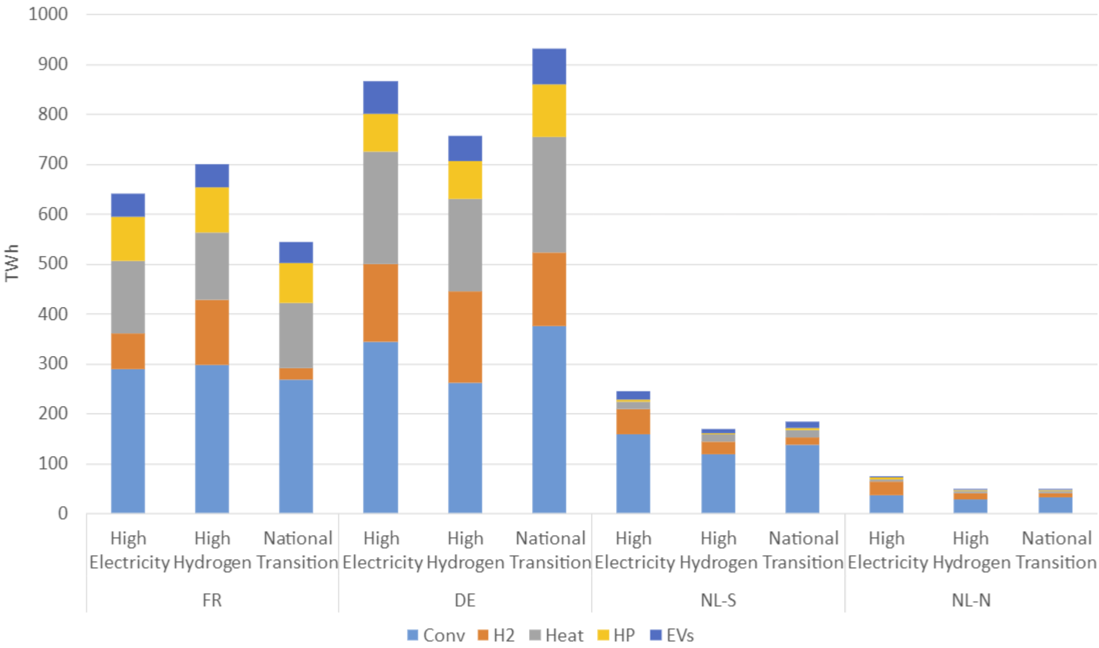


Figure D.5: Electricity demand BZ case for France, Germany and the Netherlands under the NL2 configuration

The generation mix in the BZ case for the three scenarios (Figure d.6) shows a high share of VRE in Germany electricity supply, as well for the Netherlands, whereas France exhibits also a high reliance on nuclear. Similar to the demand, the distribution of generation between the Dutch BZs show higher generation in NL-S and lower in NL-N.

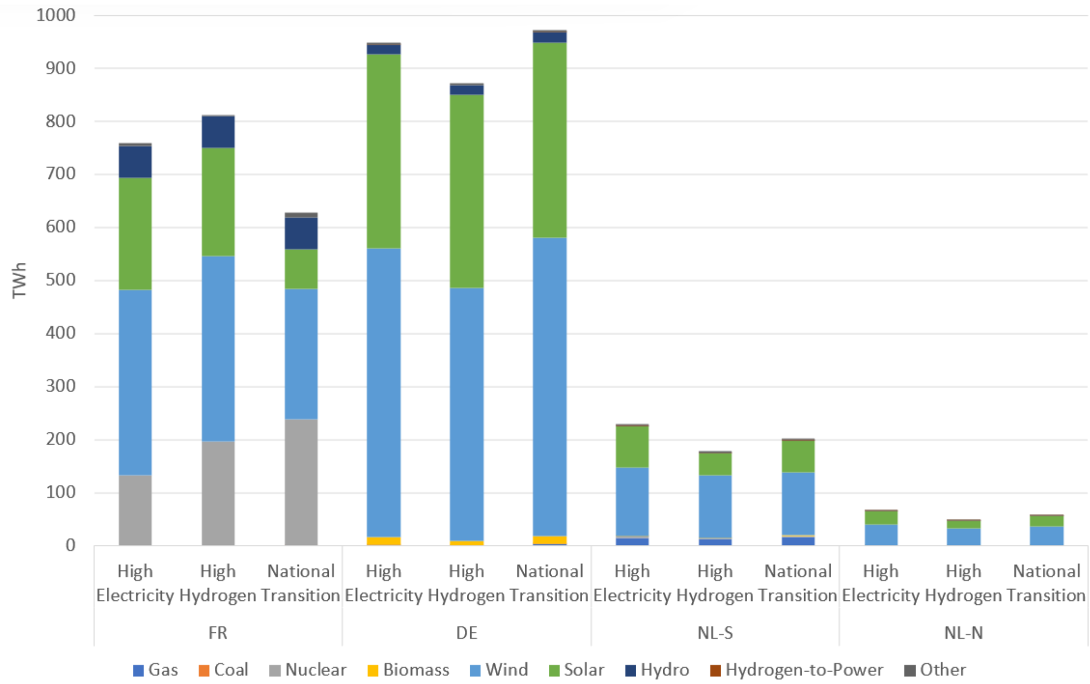
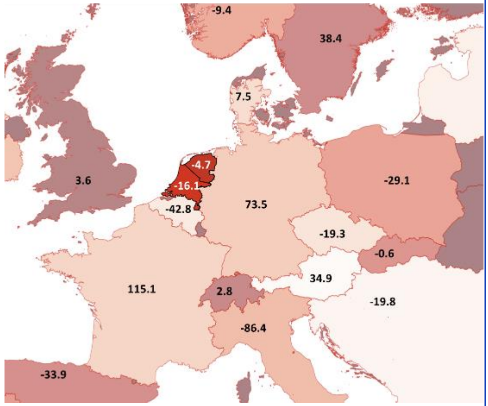


Figure D.6: Generation mix BZ case for France, Germany and the Netherlands under the NL2 configuration

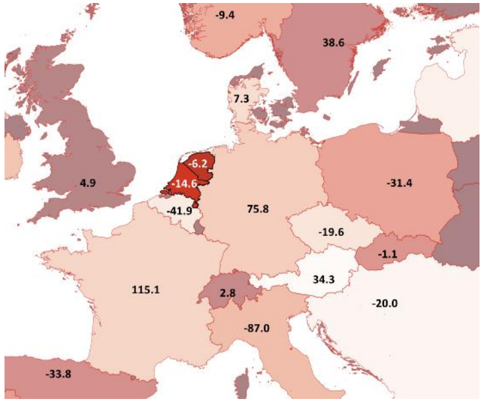
Net Positions

Figure D.7: NL2 configuration. Net positions [TWh] (+ exporting, - importing)

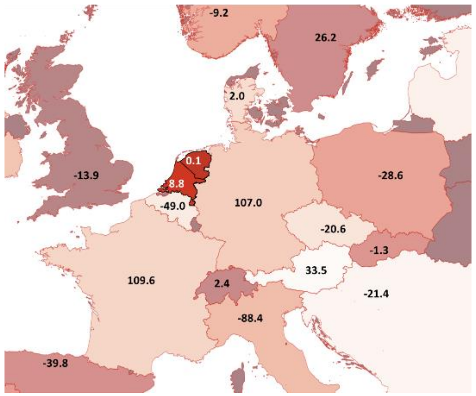
High Electricity Base case



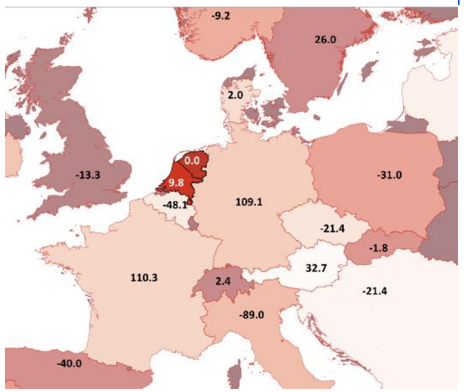
High Electricity BZ case



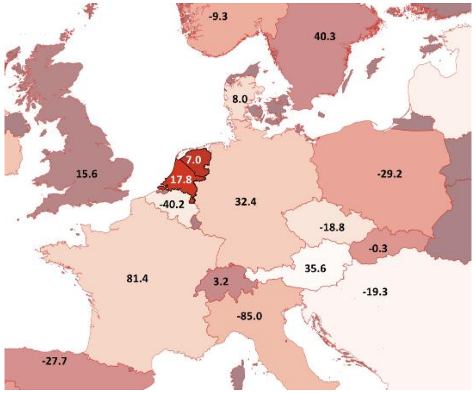
High Hydrogen Base case



High Hydrogen BZ case



National Transition Base case



National Transition BZ case

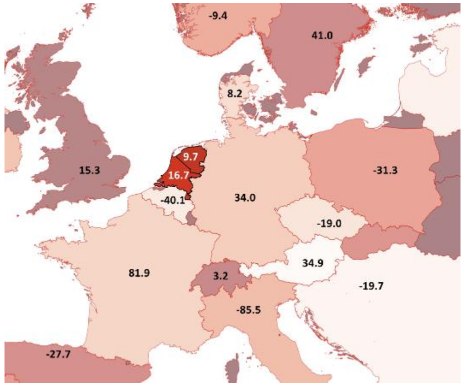


Figure D.8: DE2 configuration. Net positions [TWh] (+ exporting, - importing)

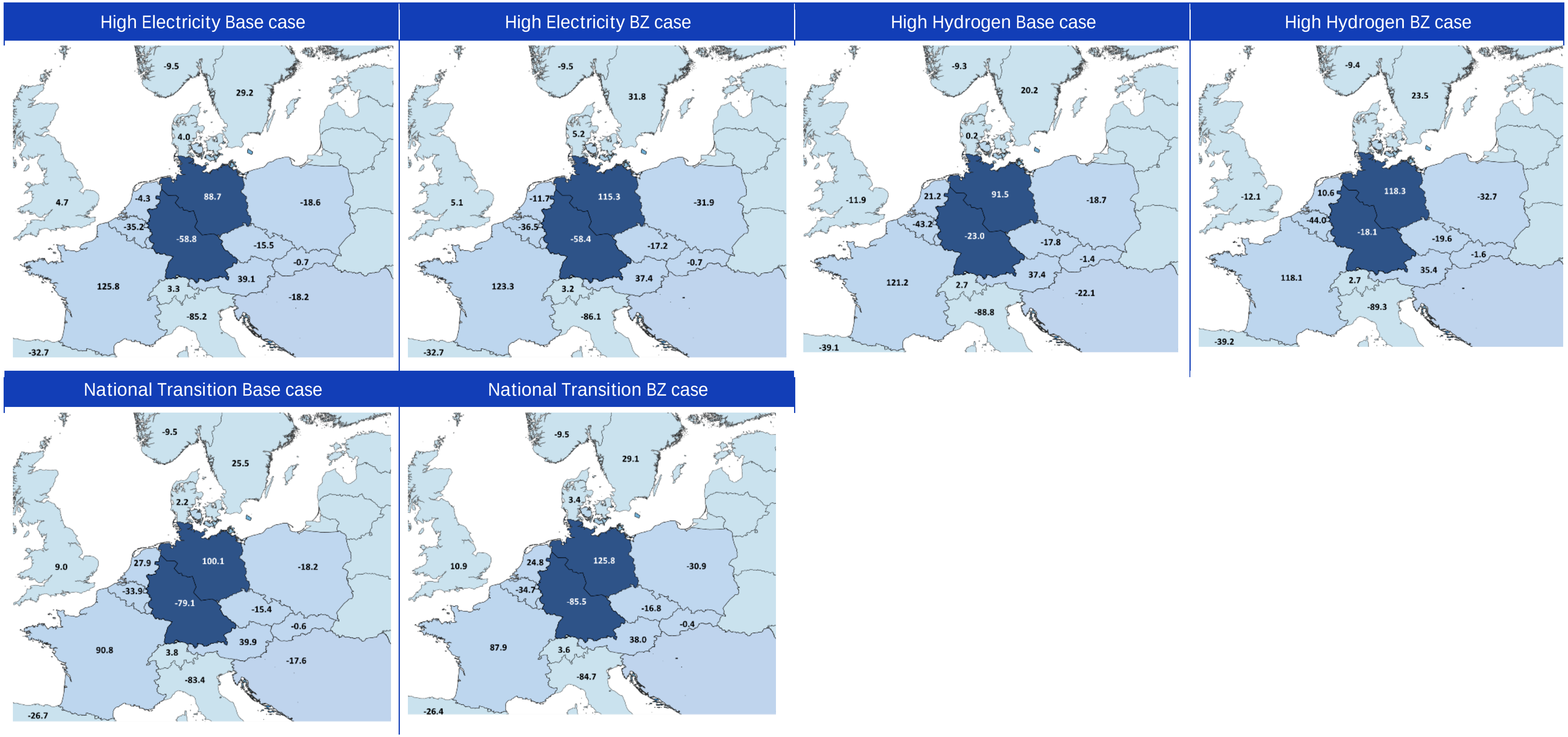
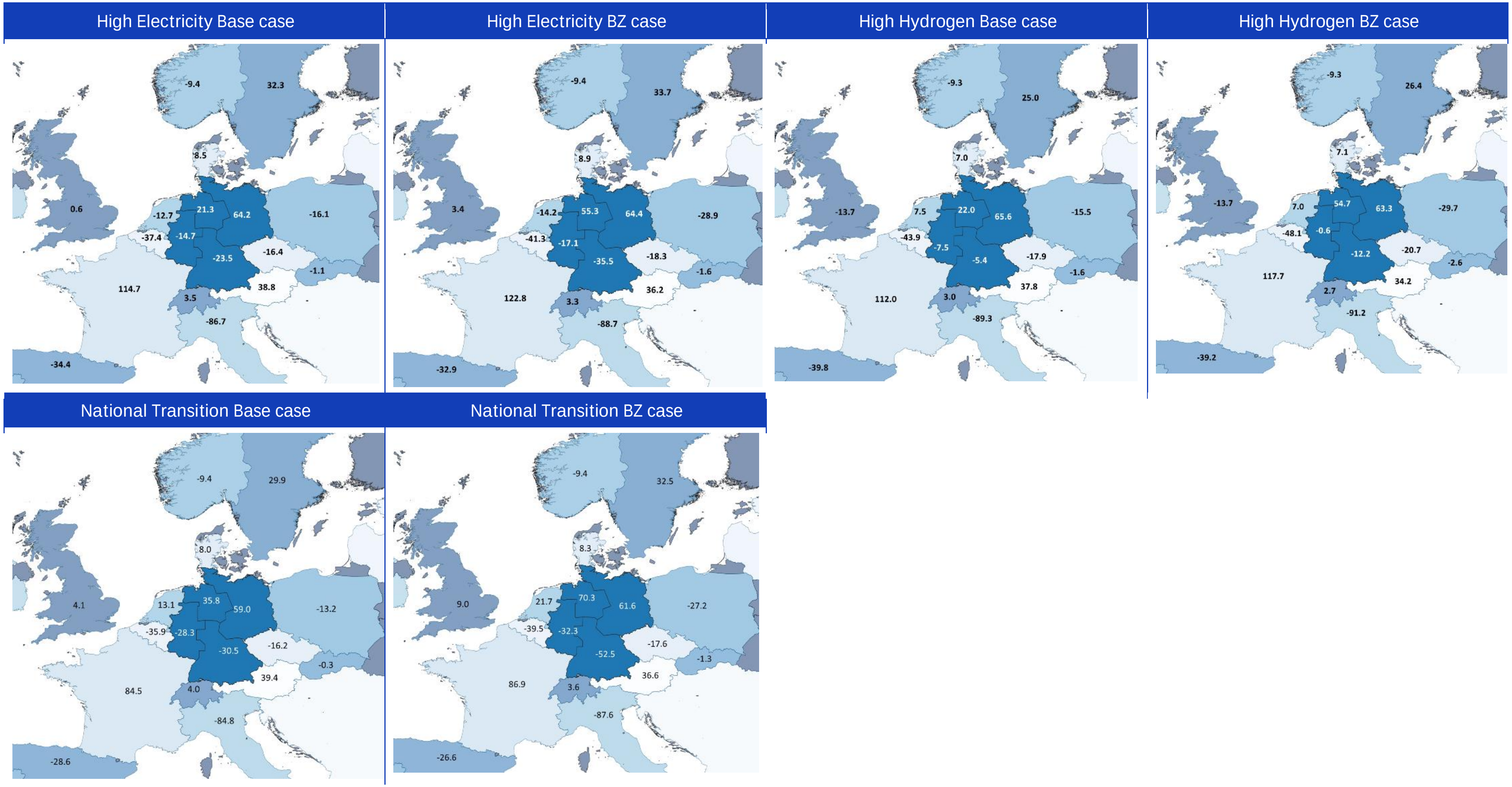


Figure D.9: DE4 configuration. Net positions [TWh] (+ exporting, - importing)



Net Cross-zonal flows

The net cross-zonal flows including the virtual lines (with exception of the NL2 configuration) for the base case and BZ case are presented in the following tables. First column shows the exporting country, first row the importing country. For example, in Table D.1, the Netherlands exports 15.2 TWh to Belgium and imports 4.3 TWh from Denmark. Flows under 0.1 TWh are not visualized for readability purposes.

Table D.1: DE2-High Electricity-Base case [TWh]

	BE	CZ	DK	FI	DE-N	DE-S	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL
BE																			
CZ	0.2					0.3			1.3	3.4						2.7			
DK												4.3	3.1		3.3				4.3
FI																	2.7		
FR	9.3	0.2			0.2	9.3	0.5	45.2	0.1		31.2		2.8	23.4					3.3
DE-N	2.0	3.4	10.9			48.4			5.1	0.8		3.9	5.2		4.5	0.6		0.3	3.7
DE-S	2.3								0.3					5.3		0.4			
IE													1.1						
PL																1.0			
PT											1.4								
SK									0.7							8.6			
SE				18.7					5.1						8.5		5.1		
UK	6.0																		13.3
CH								28.3										3.8	
NO													2.4						4.4
BK								2.3											
BT									5.7										
AT	0.2	19.0				1.5		9.5	0.6	5.5						7.0			
NL	15.2	0.8				7.8			0.6	0.2						0.2			

Table D.2: DE2-High Electricity-BZ case [TWh]

	BE	CZ	DK	FI	FR	DE-S	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL
BE																			
CZ	0.1								3.3	4.9						3.2			
DK												3.1	2.0		2.6				3.5
FI																	2.7		
FR	8.7	0.2				7.4	0.5	45.2	0.1		31.2		3.4	24.1					2.5
DE-N	3.6	8.5	6.0		0.4	53.6			12.9	1.9		2.5	3.7		3.0	1.1		1.8	16.3
DE-S	2.0	0.8							1.3	0.2				5.0		0.6			
IE													1.2						
PL																0.7			
PT											1.5								
SK									2.1							10.2			
SE				18.0					5.0						9.3		5.0		
UK	5.8																		11.1
CH								28.6										3.7	
NO													1.6						3.8
BK								2.6											
BT									5.7										
AT	0.2	18.1				0.7		9.6	0.9	5.7						7.8			
NL	16.2	1.1				6.6			1.2	0.2						0.3		0.1	

Table D.3: DE2-High Hydrogen-Base case [TWh]

	BE	CZ	DK	FI	DE-N	DE-S	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL
BE																			
CZ									1.0	4.6						3.3			
DK												7.6	4.8		5.3				3.4
FI																	2.7		
FR	7.7	0.2			0.2	5.6	0.5	45.6			38.0		3.5	19.0					0.8
DE-N	1.7	3.7	21.0			37.9			5.2	0.9		6.7	7.9		7.6	0.8		0.4	
DE-S	10.4	1.5							0.9	0.4				15.3		0.7			
IE													0.7						
PL																1.3			
PT											1.1								
SK									0.3							10.4			
SE				20.9					5.1						3.2		5.3		
UK	4.4																		4.2
CH								30.4										6.5	
NO													3.6						3.2
BK								2.8											
BT									5.8										
AT	0.2	19.6				0.4		9.9	0.6	5.9						8.1			
NL	18.9	1.6			2.0	8.2			1.0	0.3						0.3		0.3	

Table D.4: DE2-High Hydrogen-BZ case [TWh]

	BE	CZ	DK	FI	FR	DE-S	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL
BE																			
CZ									3.2	6.1						3.8			
DK												6.2	3.7		4.1				2.2
FI																	2.7		
FR	6.9	0.2				2.6	0.5	45.6	0.1		38.2		4.3	19.8					
DE-N	3.4	8.9	14.9		0.5	43.3			13.2	2.0		5.1	6.1		5.8	1.2		1.9	12.0
DE-S	10.6	2.8							2.0	0.6				15.2		0.9		0.5	
IE													0.7						
PL																1.1			
PT											1.0								
SK									1.9							11.9			
SE				20.1					5.1						4.4		5.2		
UK	4.0																		1.4
CH								30.7										7.0	
NO													2.8						2.2
BK								3.0											
BT									5.7										
AT	0.1	19.1						10.0	0.9	6.2						9.0			
NL	19.1	1.8				4.8			1.5	0.4						0.4		0.4	

Table D.5: DE2-National Transition-Base case [TWh]

	BE	CZ	DK	FI	FR	DE-N	DE-S	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL
BE							2.5												
CZ	0.2						0.5		1.1	3.4						2.7			
DK												5.6	4.4		4.2				3.1
FI																	2.7		
FR	7.1	0.1					7.0	44.8			23.9			22.5					
DE-N	2.0	3.5	15.0				55.7		5.1	0.8		4.9	6.7		5.8	0.7		0.4	
DE-S									0.1					1.4		0.4			
IE					1.0														
PL																1.0			
PT											2.8								
SK									0.5							8.6			
SE				19.4					5.0						6.4		5.2		
UK	6.2				13.5														4.3
CH								26.0										1.8	
NO													3.9						3.1
BK								3.0											
BT									5.7										
AT	0.2	18.2					1.6	9.5	0.6	5.3						6.9			
NL	20.6	1.4			0.3	0.6	13.8		0.9	0.3						0.3		0.2	

Table D.6: DE2-National Transition-BZ case [TWh]

	BE	CZ	DK	FI	FR	DE-S	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL
BE						4.1												
CZ	0.1					0.2		3.0	4.6						3.2			
DK											4.0	3.3		3.1				2.6
FI																2.6		
FR	6.1	0.1				5.8	44.8			23.9			22.2					
DE-N	3.6	8.5	9.6		0.6	62.8		12.7	1.9		3.4	5.2		4.0	1.1		1.8	10.7
DE-S								0.8					3.5		0.5			
IE					0.9							0.1						
PL															0.8			
PT										2.5								
SK								1.9							10.1			
SE				18.4				5.0						8.1		5.0		
UK	6.0				11.8													4.7
CH							27.1										2.2	
NO												2.9						2.7
BK							3.1											
BT								5.6										
AT	0.2	17.4				1.3	9.7	0.9	5.4						7.7			
NL	22.9	1.9			1.8	16.2		1.5	0.4						0.3		0.5	

Table D.7: DE4-High Electricity-Base case [TWh]

	BE	CZ	DK	FI	FR	DE-NW	DE-W	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL	DE-NE	DE-S
CZ	0.1						0.5			0.9	1.9						1.9					0.7
DK													2.1	1.6		2.6				3.5		
FI																		2.7				
FR	5.2						1.1	0.7	45.3			33.1		5.8	23.2					0.2		0.1
DE-NW	0.7						15.9			0.4				6.9						7.5		15.9
DE-W	9.2										0.2						0.2		0.8			
IE														1.3								
PL																	0.7					
PT												1.3										
SK										0.6							6.4					
SE				19.1						5.1						8.0		5.1				
UK	5.4																			11.9		
CH									31.4										4.0			
NO														1.0						3.6		
BK									0.5													
BT										5.8												
AT	0.1	20.3							9.5	0.5	5.5						5.9			0.1		1.4
NL	12.9						0.9															1.1
DE-NE	0.3	2.2	1.3			26.1	5.4			3.4	0.5		3.0			3.4	0.4			0.7		17.7
DE-S	3.4						1.2								8.6		0.2					

Table D.8: DE4-High Electricity-BZ case [TWh]

	BE	CZ	DK	FI	FR	DE-NW	DE-W	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL	DE-S
BE																					
CZ										2.6	5.0						3.4				
DK													2.0	1.9		2.8				3.3	
FI																		2.7			
FR	9.4	0.1					5.4	0.6	45.2			31.6		4.2	22.3					2.6	1.3
DE-NW	1.1	0.8					16.3			2.3	0.2			3.6			0.1		0.1	18.6	22.1
DE-W	6.2	0.9								0.6	0.9						0.5		3.1		
IE														1.1							
PL																	0.9				
PT												1.3									
SK										1.7							10.7				
SE				18.8						5.1						8.8		5.0			
UK	4.8																			10.6	
CH									31.8										6.1		
NO														1.2						3.5	
BK									1.7												
BT										5.7											
AT		20.4							10.0	0.8	6.2						8.4				0.6
NL	16.1	0.2					1.4			0.2											7.2
DE-NE	0.3	5.8	1.0			10.0	6.2			9.3	1.4		2.0			2.6	0.9		0.9	0.9	23.1
DE-S	3.2	1.0					0.1			1.4	0.3				12.3		0.5				

Table D.9: DE4-High Hydrogen-Base case [TWh]

	BE	CZ	DK	FI	FR	DE-NW	DE-W	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL	DE-NE	DE-S
CZ	0.1						0.6			0.7	2.6						2.3					
DK													3.2	2.2		2.6				1.7		
FI																		2.8				
FR	4.4						0.5	0.6	45.7			38.8		4.5	19.1							
DE-NW	0.7						14.9			0.4				9.9						7.7		14.5
DE-W	14.8										0.3						0.2		1.2			
IE														0.8								
PL																	0.9					
PT												1.1										
SK										0.3							7.6					
SE				20.6						5.2						3.0		5.2				
UK	3.8																			1.5		
CH									32.5										6.8			
NO														1.5						1.3		
BK									1.4													
BT										5.8												
AT	0.1	21.5							9.6	0.5	5.9						6.7			0.1		1.1
NL	15.4				1.2		2.5															1.1
DE-NE	0.3	2.4	2.6			26.3	3.3			3.4	0.6		5.8			6.5	0.5			0.6		13.4
DE-S	4.1				0.3		2.2			0.3					17.2		0.3					

Table D.10: DE4-High Hydrogen-BZ case [TWh]

	BE	CZ	DK	FI	FR	DE-NW	DE-W	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL	DE-S
BE																					
CZ										2.5	6.3						3.9				
DK													3.0	2.3		2.8				1.3	
FI																		2.7			
FR	7.4	0.1					1.2	0.6	45.7			38.2		5.0	19.0						0.5
DE-NW	1.1	0.9					14.3			2.4	0.2			6.8			0.2		0.1	19.5	17.0
DE-W	12.9	1.9								0.9	1.0						0.7		4.6		
IE														0.8							
PL																	1.2				
PT												1.0									
SK										1.5							12.3				
SE				20.4						5.2						3.6		5.2			
UK	3.1																				
CH									32.7										8.4		
NO														1.4						1.1	
BK									2.6												
BT										5.8											
AT		21.3							10.2	0.8	6.8						9.4				
NL	19.2	0.4					1.3			0.3				0.6							7.3
DE-NE	0.3	6.1	2.3			7.9	5.4			9.5	1.4		5.0			5.5	0.9		0.9	0.5	17.6
DE-S	4.0	2.8					0.4			2.1	0.6				19.5		0.7		0.2		

Table D.11: DE4-National Transition-Base case [TWh]

	BE	CZ	DK	FI	FR	DE-NW	DE-W	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL	DE-S
CZ	0.1						0.9		0.1	1.5						2.1				0.2
DK												2.8	2.5		2.5				1.6	
FI																	2.7			
FR	4.1						0.7	44.9			26.1			22.6						
DE-NW	0.9	0.2			0.1		18.1		0.4				8.9						6.8	18.9
DE-W	3.6									0.2						0.1		0.5		
IE					0.8								0.2							
PL							0.2									1.0				
PT											2.5									
SK																7.0				
SE				19.4					5.1						6.2		5.1			
UK	5.8				10.7														1.1	
CH								29.0										0.7		
NO													1.9						1.2	
BK								1.5												
BT									5.8											
AT	0.1	18.6						9.4	0.4	5.0						5.9				1.1
NL	16.6				1.8		3.8													2.3
DE-NE	0.3	2.4	1.4			18.5	5.7		2.8	0.5		3.1			3.7	0.4			0.5	19.5
DE-S	4.3				0.4		3.4							3.1		0.3				

Table D.12: DE4-BZ case-National Transition [TWh]

	BE	CZ	DK	FI	FR	DE-NW	DE-W	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL	DE-S
BE																				
CZ									2.3	4.3						3.1				
DK												2.2	2.6		2.7				1.9	
FI																	2.7			
FR	7.0						4.0	44.9			24.1			19.9						0.9
DE-NW	1.2	0.9			0.1		18.7		2.3	0.2			6.2			0.1		0.1	18.4	26.9
DE-W	1.0	0.3							0.4	0.8						0.4		2.6		
IE					0.9								0.3							
PL																0.9				
PT											2.6									
SK									1.5							10.0				
SE				18.8					5.1						8.0		5.0			
UK	5.3				11.7														3.3	
CH								31.3										4.6		
NO													2.2						1.9	
BK								1.5												
BT									5.7											
AT	0.1	19.6						9.9	0.7	5.9						7.9				0.9
NL	21.8	0.4			1.1		6.1		0.3											17.8
DE-NE	0.3	5.8	1.1			4.9	6.5		8.9	1.3		2.2			2.8	0.8		0.9	0.5	25.6
DE-S	2.7	0.3					2.7		1.0	0.1				12.4		0.4				

Table D.13: NL2-High Electricity-Base case [TWh]

	BE	CZ	FI	DE	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL-S	NL-N
CZ							6.1	14.1										
DK				2.4						0.8	0.6		1.1					2.8
FI															2.6			
DE	21.0	13.1					9.4				0.7	14.9				5.7	11.1	2.4
IE											1.7							
PT									1.5									
SK							2.9							10.6				
SE			17.0	0.6			5.0						11.8		4.8			
UK	3.5																10.7	
CH						30.6										5.8		
NO											0.4							3.1
BK						1.0												
BT							5.7											
AT		26.5				9.6								10.2				
NL-S	9.2																	
FR	9.0			1.8	0.9	45.2			32.4		7.2	18.7						
NL-N																	3.5	

Table D.14: NL2-High Electricity-BZ case [TWh]

	BE	CZ	FI	DE	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL-S	NL-N
CZ							6.6	15.2										
DK				2.5						0.7	0.4		1.1					2.6
FI															2.6			
DE	20.5	15.4					10.8				0.4	14.1				7.1	10.4	2.5
IE											1.6							
PT									1.5									
SK							3.2							10.9				
SE			16.9	0.7			5.0						11.8		4.8			
UK	3.9																11.1	
CH						30.6										4.9		
NO				0.2							0.3							2.9
BK						1.3												
BT							5.7											
AT		26.0				9.8								10.4				
NL-S	8.7																	
FR	8.8			2.1	0.8	45.2			32.3		7.2	18.7						
NL-N																	1.8	

Table D.15: NL2-High Hydrogen-Base case [TWh]

	BE	CZ	DK	FI	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL-S	FR	NL-N
CZ							5.5	15.3											
DK										5.3	3.0		3.5						1.6
FI															2.6				
DE	23.8	14.6	11.4				9.9			3.5	4.9	20.8	4.5			6.6	3.6	3.0	0.3
IE											1.2								
PT									1.1										
SK							2.4							11.6					
SE				19.5			5.1						5.3		5.1				
UK	1.9																1.9		
CH						31.7										7.6			
NO											2.8								1.3
BK						1.1													
BT							5.8												
AT		26.8				9.9								10.9					
NL-S	17.6																		
FR	5.6				0.7	45.6			38.7		5.9	16.1							
NL-N																	3.3		

Table D.16: NL2-High Hydrogen-BZ case [TWh]

	BE	CZ	DK	FI	IE	IT	PL	SK	ES	SE	UK	CH	NO	BK	BT	AT	NL-S	FR	NL-N
CZ							6.1	16.2											
DK										5.3	3.0		3.4						1.4
FI															2.6				
DE	23.0	17.0	11.1				11.4			3.6	4.7	20.5	4.4			8.0	2.7	2.5	0.1
IE											1.2								
PT									1.2										
SK							2.7							11.8					
SE				19.4			5.1						5.3		5.2				
UK	2.6																1.7		
CH						31.8										7.1			
NO											2.6								1.3
BK						1.4													
BT							5.7												
AT		26.6				10.1								11.1					
NL-S	17.0																		
FR	5.5				0.7	45.6			38.8		6.2	15.9							
NL-N																	2.8		

Table D.17: NL2-National Transition-Base case [TWh]

	BE	CZ	DK	FI	DE	IT	PL	SK	ES	UK	CH	NO	BK	BT	AT	NL-S	FR	NL-N
CZ							6.3	13.6										
DK					6.9					0.5		0.5						0.6
FI														2.5				
DE	12.0	12.4					9.1				14.6				5.3		0.6	
IE										0.9							0.6	
PT									2.7									
SK							3.1						10.2					
SE			0.4	16.6	1.7		5.0					11.9		4.8				
UK	3.7				0.4											5.3	8.4	
CH						29.8									5.0			
NO					1.5					0.7								0.8
BK						0.8												
BT							5.7											
AT		26.4				9.5							10.0					
NL-S	20.6				7.8													
FR	4.1					44.8			25.1		17.0							
NL-N					3.3											5.1		

Table D.18: NL2-National Transition-BZ case [TWh]

	BE	CZ	DK	FI	DE	IT	PL	SK	ES	UK	CH	NO	BK	BT	AT	NL-S	FR	NL-N
CZ							6.8	14.7										
DK					6.8					0.3		0.4						1.2
FI														2.6				
DE	11.5	14.7					10.5				13.9				6.7		0.3	
IE										1.0							0.6	
PT									2.7									
SK							3.3						10.5					
SE			0.4	16.5	1.8		5.0					12.5		4.8				
UK	4.0				0.5											4.6	7.9	
CH						30.0									4.2			
NO					1.4					0.5								1.5
BK						1.0												
BT							5.7											
AT		25.8				9.8							10.2					
NL-S	20.6				8.9													
FR	3.9					44.8			25.0		17.0							
NL-N					4.3											8.2		

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