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Spatial incentives for power-to-hydrogen through market splitting

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Open-Minded

Spatial Incentives for Power-to-hydrogen through Market Splitting

Marco Sebastian Breder, Felix Meurer, Michael Bucksteeg, and Christoph Weber

Abstract

Germany's energy transition is associated with increasing congestion in the electricity transmission grids due to increasing infeed from renewable energy sources, especially from wind turbine installation at the periphery in coastal areas. Here, regional differences in generation and demand lead to grid bottlenecks from the northern to the southern parts of the country, thus leading to grid expansion requirements towards the load centers. However, long lead times for grid expansion in combination with the rapid expansion of renewables amplify the grid congestion. The provision of flexibility is one way to overcome this issue. In zonal markets, load-side flexibility can mitigate this situation, but it can also exacerbate it. Hence, adequate spatial incentives are crucial. To date, research has discussed possible market splits as a mid-term solution to improve congestion management, recognizing that the first-best solution of nodal prices is controversial in Europe. Nevertheless, adjusted bidding zones, e.g., by market splitting, can offer a solution. In the context of energy transition and ambitious decarbonization goals, hydrogen becomes important both as a storage option for renewable energy surplus and a green fuel for multiple usages. The German government already foresees 10 GW of electrolyser capacity by 2030, yet their locations will strongly affect congestion in the electricity grid. Therefore, this study investigated the impact of a possible market split on both the operation of and the investment in electrolysers. We apply an optimization approach including endogenous investment decisions linked to a detailed scheduling model. The investments are iteratively adjusted based on a Benders decomposition approach to study the impacts of market splitting on both the amount and the location of investments in terms of the electrolysers' capacity and operation. In addition to conducting an analysis of spatial incentives, this study considered incentives through different CO_2 prices.

Keywords: Hydrogen, German Energy Transition, Electricity Market, Operations Research, Market Split

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1 Introduction

The energy transition strategy aims to decarbonize the energy sector by replacing fossil fuels with renewable sources of energy. This strategy involves covering energy demand in the future primarily with renewable energy from wind and solar power. This form of energy supply also contributes to reducing energy import dependencies. Due to topological and meteorological conditions, wind farms have mainly been built at the periphery of European countries. However, wind feed-in that occurs far from the load centers requires sufficient transmission capacity. Delays in grid expansion present a challenge for European Transmission System Operators (TSOs) causing them to face grid congestion on a daily basis. These challenges underscore the increasing importance of congestion management and raise questions regarding the delimitation of bidding zones.

To date, research has addressed different aspects of grid congestion and possible solutions. In general, economists agree that nodal pricing is the first-best solution for pricing scarce transmission capacity (Schweppe et al. 1988; Hogan 1992; Ehrenmann and Smeers 2005; Bjørndal and Jörnsten 2007; Deilen et al. 2019). However, nodal prices are a controversial issue in Europe, which is why a zonal pricing mechanism has been implemented. To guarantee efficient pricing of inter-zonal congestion, a regular review of bidding zones is foreseen in the European Union (EU) guideline on Capacity Allocation and Congestion Management (CACM) (cf. Commission Regulation (EU) 2015/1222 2015). Some studies have addressed the optimal delimitation of bidding zones. For instance, Felling and Weber (2018) developed a hierarchical cluster algorithm to identify possible new price zone configurations. While small bidding zones might lead to strong price variations across locations, the impact of larger bidding zones has repeatedly been found to be limited—at least regarding average prices (Trepper et al. 2015; Egerer et al. 2016; Felling and Weber 2018). Yet studies have also shown the substantial effects of congestion management and have reported more frequent zero and negative prices in the more peripherical northern areas of Germany. With regard to our investigation, the considered studies essentially deal with two aspects: the computation of robust configurations with different cluster algorithms (Burstedde 2012; Kang et al. 2013; Breuer and Moser 2014; Klos et al. 2014) and the analysis of the system's effects with exogenously given bidding zones (Trepper et al. 2015; Egerer et al. 2016; Blume-Werry et al. 2017).

Despite the extensive number of studies on bidding zone configurations and their impacts, their interplay with an emerging power-to-hydrogen (PtH_2) infrastructure has not yet been considered. To date, most previous studies have focused on the interdependencies between hydrogen supply chains and electricity systems. Vom Scheidt et al. (2022) combined a electrolytic hydrogen supply chain model with an electricity system dispatch model for a cross-sectoral case study of Germany.

They considered nodal electricity prices and hydrogen infrastructure investments. However, the authors do not point out how the electrolysers, as a new flexibility provider, can be integrated in a system-oriented way due to the fact that they assume exogenously defined electricity demand by the electrolysers. Furthermore, they simplify the geographical scope of the electricity system by focusing on Germany. Hence, potential effects resulting from electricity exchanges with neighboring countries cannot be analyzed. The authors recommend a broader geographic scope for further research. With respect to the impacts on the electricity system, Runge et al. (2019) focused on optimizing supply chains for hydrogen stored in liquid organic hydrogen carriers under the influence of electricity prices resulting from different electricity market designs. They stated that, in case of nodal pricing, it is economically attractive to transport fuels from northern to southern Germany. The authors called for further analysis of the impacts on the electricity system. Another study considered the effects of the electrolysers for redispatch, but it did not consider the perspective of day-ahead electricity wholesale markets (Xiong et al. 2021). Furthermore, the authors used data from 2015; thus, the study's findings did not reflect future developments, especially regarding electricity grids. Further research on PtH_2 has focused on flexible electrolyser operation (Bødal et al. 2020; Zhang et al. 2020) and the interrelationships between electricity markets and hydrogen supply (Rose and Neumann 2020).

This literature review reveals that there is a lack of investigation of the interplay between the electrolysers and other flexibilities in power systems as well as on the specific interplay between the incentives related to market splitting and PtH_2. Against this background, our main contribution is the investigation of the interplay between the electrolysers and market splitting using a detailed electricity market model. We also consider the longer-term impacts on investment propensity and the location of the electrolysers using a detailed optimization model based on Benders decomposition. We focus on the impact of market splitting and the pricing of scarce transmission capacity on the integration of PtH_2. Additionally, we investigate the impact of different CO_2 price scenarios as a robustness check. We expected two effects. On the one hand, we assume there will be an effect from market split on utilization of H_2. On the other hand, we assume the effects of CO_2 price variation on utilization of hydrogen. The discussion of these effects is presented in Section 4.

The remainder of this paper is organized as follows. In Section 2, we explain the methodology regarding the Benders decomposition approach, Iterative Optimization of (Dis-)Investment in Large Energy Systems (IDILES), which includes the electricity and heat market model, Joint Market Model (JMM) as a subproblem, embedding it in an investment model as a master problem. Furthermore, we briefly explain the concept for modelling PtH_2 technologies. Section 3 presents the data description and scenario framework. Section 4 discusses the results, focusing on the impacts on spatial investment incentives, impacts on the utilization of electrolysers, the system costs effects, and the impacts on congestion and renewable integration. We conclude by providing policy implications.

2 Methodology

To study the integration of PtH2, we integrated JMM into IDILES, the Benders decomposition approach, which provides an upper level assessment of investment optimization. We used IDILES and the JMM to investigate the siting and investment decision on the one hand and the optimal operation of electrolysers on the other.

2.1 Iterative Optimization of (Dis-)Investment in Large Energy Systems (IDILES)

The model framework IDILES (Leisen et al. 2022) is based on the dispatch model JMM (Figure 1). Using Benders decomposition approach, IDILES co-optimizes long-term investment and disinvestment decisions and the operation of the assets. The capacities are iteratively adjusted to meet the equilibrium conditions. The effects of the investment and disinvestment decisions on market prices (and thus on other related decisions) and system costs are considered consistently. While the subproblem of IDILES is represented by the JMM, which minimizes operational costs, the master problem minimizes the long-term costs, including operational, investment, and fixed costs. Here, investment and fixed costs are relevant for investments, while only the latter are relevant for disinvestments. Thus, disinvestment and investment decisions are treated differently. A more detailed model description can be found in Leisen et al. (2022).

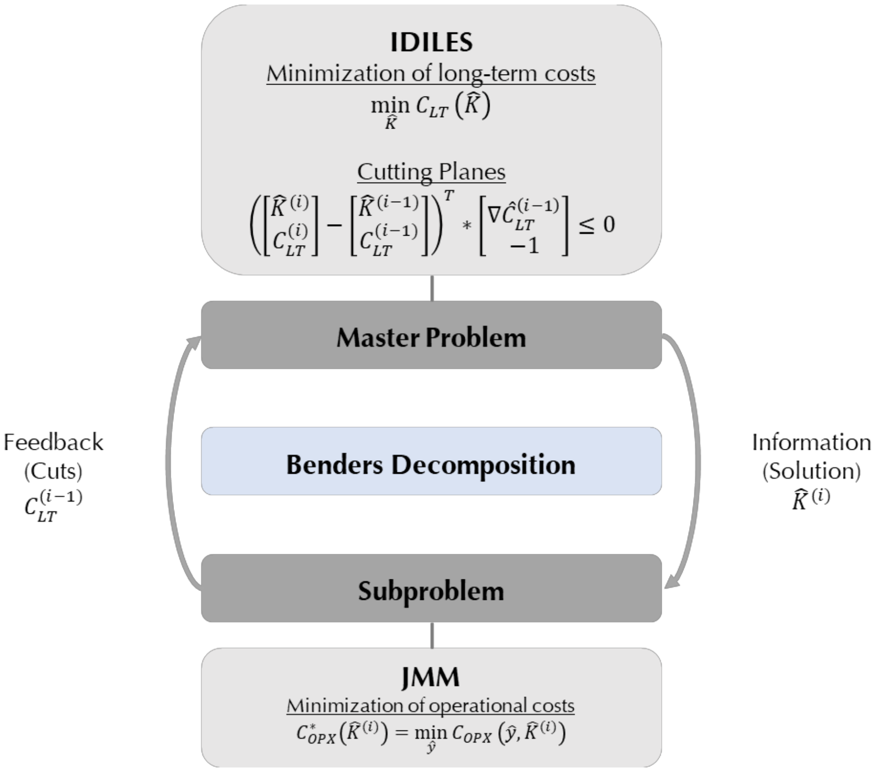


Figure 1: IDILES approach. Figure adapted from Leisen et al. (2022).

Equation (1) shows the formulation of the general problem:

$$\min_{\hat{K}} C_{LT}(\hat{K})$$

$$C_{LT}(\hat{K}) = C_{OPX}^{*}(\hat{K}) + C_{CPX}(\hat{K}) \tag{1}$$

$$A\hat{y} + B\hat{K} \geq d$$

Accordingly, the long-term costs C_{LT} consisting of optimized operational costs C_{OPX}^{*}[1] and capacity-related costs C_{CPX} are minimized. As previously mentioned, capacity-related costs include investment costs and fixed costs. The vector of the decision variables $\hat{K}$ corresponds to the installed capacities of the considered technologies. The dispatch decision variables are represented by $\hat{y}$ and the corresponding set of constraints for the operational problem is represented by $A\hat{y} + B\hat{K} \geq d$. The capacities of the investment problem are free of constraints but restricted by feedback cuts, which will be discussed below.

The JMM uses a rolling planning approach instead of a closed optimization approach to represent non-perfect foresight. To combine the investment decision with the JMM, the general problem is reformulated as a two-level problem (see Figure 1). Formally, the decomposition of the general problem can be written as shown in Equation (2):

[1] Represents minimized operational costs for a given capacity configuration $\hat{K}$.

$$\min_{\widehat{K}}\left\{C_{CPX}(\widehat{K})+\min_{\hat{y}\geq 0}\{C_{OPX}(\hat{y})|A\hat{y}\geq d-B\widehat{K}\}\right\} \tag{2}$$

As shown in Figure 1, the master problem is an optimization problem, which is restricted by the feedback cuts from the subproblem. The feedback cuts, the cutting planes, respectively, are based on feasible but non-optimal solutions that are added iteratively in order to approximate an optimal solution. The feedback cuts are represented by the examined long-term costs C_{LT}, their gradient $\nabla\hat{C}_{LT}^{(i)}$, and the respective set of installed components $\widehat{K}$ for each iteration i. A new feedback cut is created for each iteration, which defines a new search direction. In each iteration, a new, more efficient set of components will be found by considering the previous and current feedback cuts. The minimum of the long-term costs defined by the feedback cuts cannot be higher than the long-term costs under equilibrium conditions due to the convexity of the corresponding overall dual problem. Concerning applicability, a predefined margin represents a stopping criterion, such that the iteration stops when the difference in long-term costs meets this margin. For the sake of completeness, the gradient of the long-term costs $\nabla\hat{C}_{LT}^{(i)}$ is determined by the gradient in the operational costs $\nabla\hat{C}_{OPX}^{*(i)}$ and $\hat{c}_{CPX}^{(\mathrm{i})}$, which reflects the fixed costs plus additional investment costs in the case of capacity additions, as seen in Equation (3):

$$\nabla\hat{C}_{LT}^{(i)}=-\nabla\hat{C}_{OPX}^{*(i)}+\hat{c}_{CPX}^{(\mathrm{i})} \tag{3}$$

Taking the negative sum of the shadow prices $\hat{v}_t$ multiplied by the corresponding multipliers for the capacity constraints $\hat{\theta}_t$ over each restriction a and time step t, we obtain the contribution margins from the operational problem, as seen in Equation (4):

$$\frac{\partial C_{OPX}^{*}(\widehat{K}^{(i)})}{\partial\widehat{K}^{(i)}}=-\sum_{t,a}\hat{\theta}_t\cdot\hat{v}_t=-\nabla\hat{C}_{OPX}^{*(i)} \tag{4}$$

Concerning the electrolysers' operation, the relevant constraint in the subproblem is the maximum capacity that limits the electricity procurement in the electricity markets. Thus, the shadow prices reflect the contribution margins of the electrolysers. Hence, as long as the electrolysers contribute to minimizing the long-term costs, investments in the electrolysers will increase.

2.2 Joint Market Model (JMM)

For the operational level in the lower problem, we use the JMM. The JMM is a linear optimization model that covers the European power system. It determines the dispatch of power plants and storages with respect to techno-economic constraints. Using a rolling planning approach allows for considering sequential market clearing and it reduces the computation time. A more detailed model description can be found in Weber et al. (2009), Meibom et al. (2011), and Trepper et al. (2015). To illustrate the high level of detail of the JMM, it is worth mentioning the consideration of regional heat markets, control reserve markets, and further technical restrictions, such as part-load efficiencies, minimum and maximum generation, minimum operation and down times, and start-up times. Here, we focus on the day-ahead market assuming perfect foresight and no information updates, such as forecasts of volatile renewables during intraday. Given that this paper focuses on PtH_2 and market splitting, we further concentrate on equations relevant to both and on the impact of changes in capacity due to disinvestment and investment decisions.

Relevant indices are the time steps t, the technologies i, and the areas a as a subset of the regions r, which reflect the bidding zones. The objective function minimizes the total operational system costs over the optimization period. Here, the costs of fuel $c_{a,t}^{fuel}$, CO_2 certificates $c_{a,t}^{CO2}$, operation and maintenance $c_{a,i}^{O\&M}$ as well as start-up $c_{a,i}^{STARTUP}$ are considered. In the rolling planning approach, a shadow price $Sp_{a,i}^{STORAGE}$ is assigned to the content of the storages $V_{a,i,T}^{STORAGE}$ at the last time step T of the planning horizon in order to reflect the future value of the energy collected in hydro, pumped, and battery storages. This reduces the overall operational costs. To reflect the value of the produced hydrogen, we further reduce the system costs by the revenues obtained from selling the produced hydrogen $P_{a,i,t}^{PtH2}$ at a price $\xi_{a,i,t}^{PtH2}$. To improve readability, we omit additional variable costs in Equation (5), e.g., for heat production or taxes:

$$\begin{aligned} \min C_{OPX}; C_{OPX} = &\sum_{i\in I^{DISPATCH}} \sum_{a\in A} \sum_{t\in T} \left(\frac{c_{a,t}^{fuel} + f_{fuel}^{CO2-factor} \cdot c_{a,t}^{CO2}}{\eta_i} + c_{a,i}^{O\&M} \right) \cdot P_{a,i,t}^{SPOT} \\ &+ \sum_{i\in I^{ONLINE}} \sum_{a\in A} \sum_{t\in T} c_{a,i}^{STARTUP} \cdot P_{a,i,t}^{STARTUP} \\ &- \sum_{i\in I^{STORAGE}} \sum_{a\in A} Sp_{a,i}^{STORAGE} \cdot V_{a,i,T}^{STORAGE} - \sum_{i\in I^{PtH2}} \sum_{a\in A} \sum_{t\in T} \xi_{a,i,t}^{PtH2} \cdot P_{a,i,t}^{PtH2} \end{aligned} \tag{5}$$

Equation (6) provides a reduced representation of the balance equation for electricity sold on the day-ahead market, including transmission and curtailment variables.

$$\begin{aligned} &\sum_{i\in I_{a(r)}^{DISPATCH}} P_{a,i,t}^{SPOT} + P_{r,t}^{RES} - P_{r,t}^{RES_{CURT},SPOT} + \sum_{(\bar{r},r)\in RR} \left(1 - \delta_{\bar{r},r}\right) \cdot P_{\bar{r},r,t}^{TRANS,SPOT} \\ &= d_{r,t}^{ELEC} + \sum_{i\in I_{a(r)}^{StORAGE}} W_{a,i,t}^{SPOT} + \sum_{i\in I_{a(r)}^{PtH2}} W_{a,i,t}^{SPOT} + \sum_{(r,\bar{r})\in RR} P_{r,\bar{r},t}^{TRANS,SPOT} \\ &\forall t \in T^{SPOT}, \forall r \in R \end{aligned} \tag{6}$$

The balance equation ensures that supply meets demand for every hour of the year. The right side of the equation describes total demand, which consists of electricity demand from end users $d_{r,t}^{ELEC}$, charging of storages, and electrolysers' consumption $W_{a,i,t}^{SPOT}$ and exports $P_{r,\bar{r},t}^{TRANS,SPOT}$. The left side of the equation corresponds to total supply, including the production from hydro and thermal power plants as well as storages $P_{a,i,t}^{SPOT}$, infeed from volatile renewable energy sources, such as wind and solar $P_{r,t}^{RES}$, and imports $P_{\bar{r},r,t}^{TRANS,SPOT}$ from neighboring regions (with transmission losses $\delta_{\bar{r}r}$). Furthermore, the renewable infeed may be reduced by curtailments $P_{a,i,t}^{RES_{CURT},SPOT}$.

The cross-border trading of electricity is modelled using the net transfer capacity (NTC) approach. The corresponding transmission restrictions apply to all electricity transfers between bidding zones. Hence, a market splitting for Germany is also reflected by a constraint on the electricity exchange between northern and southern Germany.

The general form of these constraints is given in Equation (8):

$$P_{r,\bar{r},t}^{TRANS,SPOT} + P_{r,\bar{r},s,t}^{TRANS,ANC,+} \leq l_{r,\bar{r}}^{TRANS,MAX} \qquad (7)$$
$$\forall\, r,\bar{r} \in R, \forall s \in S, \forall t \in T$$

The exogenously fixed transmission capacity $l_{r,\bar{r}}^{TRANS,MAX}$ provides an upper limit to the sum of electricity exports $P_{r,\bar{r},t}^{TRANS,SPOT}$ and the possible export of ancillary services (positive reserves) $P_{r,\bar{r},s,t}^{TRANS,ANC,+}$.

Regarding the relevant restriction for determining the contribution margins, the maximum capacity for electricity procurement in the electricity markets is given in Equation (8). In each timestep, the sum of electricity purchased on the day-ahead market $W_{a,i,t}^{SPOT}$ and the reservation of loading capacity for the provision of negative spinning $W_{a,i,t}^{ANC,-}$ and non-spinning reverse $W_{a,i,t}^{NONSP\_ANC,-}$ cannot exceed the maximum loading capacity of the electrolysers $cap_{a,i}^{STO\_max}$.

$$W_{a,i,t}^{SPOT} + W_{a,i,t}^{ANC,-} + W_{a,i,t}^{NONSP\_ANC,-} \leq cap_{a,i}^{STO\_max} \qquad (8)$$

2.3 Modelling of Power-to-hydrogen

When modelling the integration of PtH_2 in energy market models, it is common to utilize a market-clearing mechanism to match supply and demand (Bødal et al. 2020; vom Scheidt et al. 2022). In such cases, demand is typically specified as an exogenous parameter and the price is obtained endogenously from the market-clearing mechanism. As Bucksteeg et al. (2021) demonstrated, there is another way to model PtH_2 in electricity market models. Based on the results by Böcker and Weber (2015), they argued that the value of hydrogen is equal to the opportunity costs of hydrogen consumers, which corresponds to the cost of purchasing hydrogen from other sources, such as steam reforming (Bucksteeg et al. 2021). In this case, the natural gas price $c_t^{gas}$and the costs for CO_2 compensation c_t^{CO2}, i.e., CO_2 certificates, mainly determine the use value ξ_t^{PtH2} of the electricity used in the electrolysers, as indicated in Equation (9):

$$\xi_{a,i,t}^{PtH2} = \left(c_t^{gas} + f_{gas}^{CO2-factor} \cdot c_t^{CO2}\right) \cdot \eta_{PtH2} \tag{9}$$

Here, $f_{gas}^{CO2-factor}$ is the emission factor of the natural gas used in steam reformation and η_{PtH2} is the conversion rate of the electrolysers. This approach builds on the assumption that gas consumers, e.g., industry, can choose between hydrogen from the electrolysers or from steam reforming and that the storage capacity for hydrogen is not a limiting factor.

The basic rule of operation of the electrolysers then is: the electrolysers operate whenever the electricity price is less than or equal to the use value ξ_t^{PtH2}—this may also be derived formally from the Lagrangian based on the objective function (5) and the balance Equation (6). In that case, the procurement costs of hydrogen from electrolysis are lower than the costs of alternative production routes. If the electricity price is strictly smaller than the use value, the difference corresponds to the contribution margin earned by the electrolysers. If electricity prices exceed the use value, the electrolysers will not run. In summary, the electrolysers have an incentive for utilization whenever the marginal generation costs of the price-setting technology are less than or equal to the use value.

Similar to Bucksteeg et al. (2021), the proposed approach does not explicitly consider any re-conversion of hydrogen to electricity. For the time horizon considered in the case study, namely the year 2030, this is plausible. However, such an approach is even justifiable and useful in the presence of power plants using hydrogen as fuel. The exogenously given use value for hydrogen then corresponds to the fuel price paid by these units. In this perspective, the market price of hydrogen is independent from the supply and demand or storage potentials in the regional electricity system; rather, it is determined by alternative technology routes (e.g., steam reforming) and/or international supply. For a more detailed description of the chosen approach, e.g., regarding the integration into reserve markets or the negligible role of maximum storage capacity, see Bucksteeg et al. (2021).

3 Data and Scenario Framework

Data for power plant portfolios, demand time series, NTCs, and fuel prices are based on the Ten-Year Network Development Plan (TYNDP)-scenario, Distributed Energy 2030, from ENTSO-E (2020). In order to reflect the planned coal phase-out in Germany, the remaining lignite and hard coal capacities are replaced by gas-fired power plants. For renewable infeed profiles, we use data from Open Power System (2020) based on weather information from 2016 and we scale it as described in Pöstges et al. (2022). Assumptions on CO_2 prices are based on data from World Energy Outlook (WEO) (IEA 2020; 2021). Here, we use the WEO 2020 Sustainable Development Scenario as the lower bound and the WEO 2021 Net Zero Emissions by 2050 Scenario as the upper bound for possible CO_2 price development paths to 2030. Assumptions on the investment costs and technical parameters of electrolysers are based on an extensive literature review and our own assumptions (Williams et al. 2007; Agora Verkehrswende, Agora Energiewende, and Frontier Economics 2018; Dagdougui et al. 2018; Gorre et al. 2019; IEA 2019). We further assume that by 2030 the proton exchange membrane (PEM)[2] electrolyser and alkaline electrolyser will be the dominant technologies, despite the technological opportunities of solid oxide electrolyser cells (SOECs). For a detailed description of these technologies, see Pitschak et al. (2017).

Regarding the current electrolyser capacities in Germany, we use information from DVGW (2022) and TÜV Süd (2019). Accordingly, we end up with a capacity below 100 MW for electrolysers in Germany by the end of 2021. A summary of the scenario data assumptions is given in Table 1.

Table 1: Scenario data assumption

Scenario		**Ref_low/Split_low**	**Ref_high/Split_high**
CO_2 Price	EUR/t CO_2	75	114
Fuel Prices			
Natural Gas	EUR/MWh_{th}	24.88	24.88
Coal	EUR/MWh_{th}	15.48	15.48
Oil	EUR/MWh_{th}	73.80	73.80
PtH_2			
Use Value	EUR/MWh_{el}	79.94	90.31
Investment Costs	EUR/kW	638.72	638.72
Fix Costs	EUR/kW	19.16	19.16
Conversion Rate	%	73	73

According to TSOs, Germany faces regional differences in electricity generation and demand, which lead to grid bottlenecks from northern to southern Germany (Rippel et al. 2018). To investigate this issue with the JMM, we split the German market into two bidding zones: a north zone and a south zone (Figure 2). The market split is based on a simplifying approach, which allows us to examine the main effects of a reconfiguration of the German bidding zone.

[2] The abbreviation PEM also stands for polymer electrolyte membrane.

Here, we use the grid data information obtained from ENTSO-E (2020). Nodal prices from the Osmose research project[3] serve as indicators to divide Germany into north and south zones along federal state borders (Figure 2). This simplified market split based captures key features of the north and the south zones, as illustrated by the duration curves for residual loads shown in Figure 2. Although being somewhat simplified, we expect this approach to reveal the key interdependencies in our analysis.

The thermal transmission capacity is aggregated to the level of interzonal borders, which results in a net transfer capacity of about 19.4 GW across the north-south zonal market split in Germany. To allocate the controllable generation capacities, we base our distribution on data from BNetzA (2021). The distribution of the regional renewable energy source infeeds as well as the demand time series is done using an internal tool that allows for the creation of a time series at the county level (NUTS-3)[4] and scaling of the data to match aggregate TYNDP time series. The time series of the counties in the south zone and the north zone are added to obtain the zonal time series.

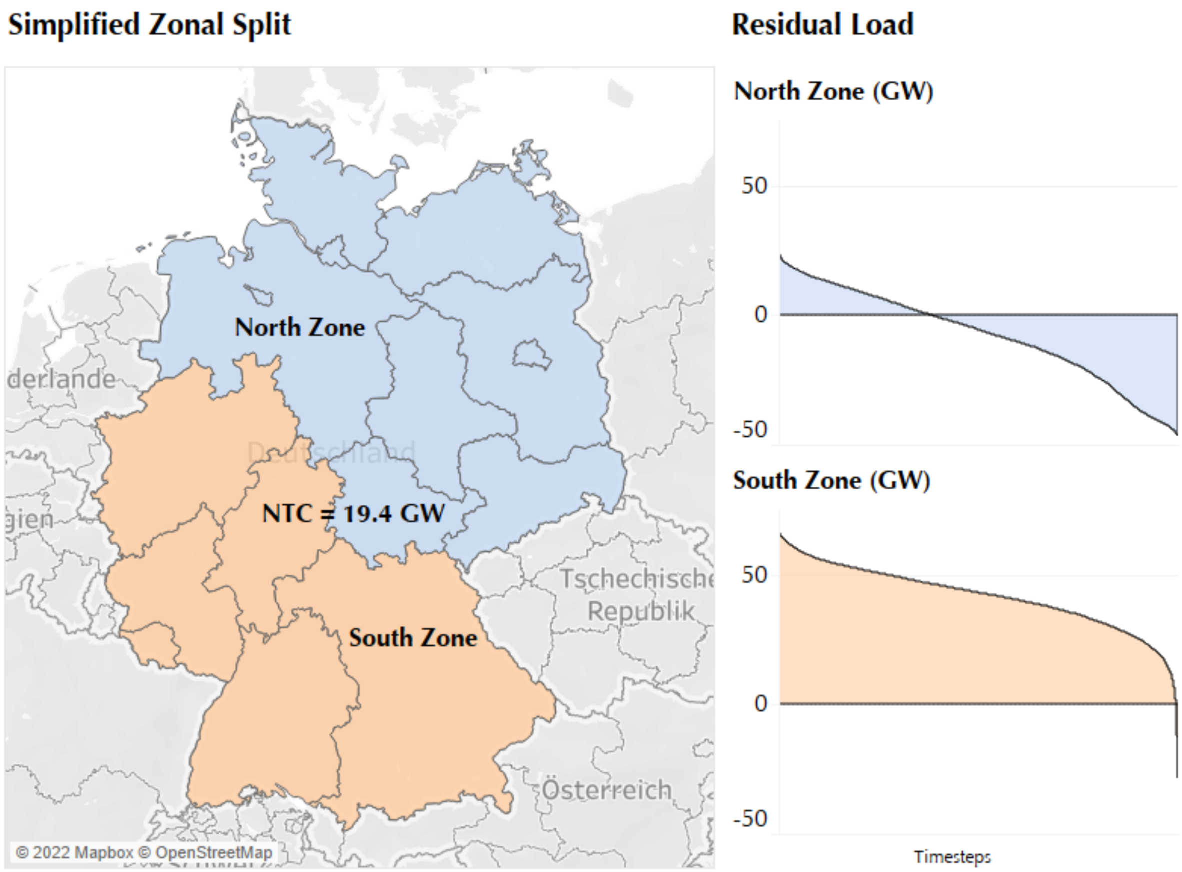


Figure 2: Simplified market split of the German bidding zone

[3] OSMOSE (https://www.osmose-h2020.eu/).
[4] In Germany, the NUTS3 regions correspond to counties ("Landkreise") and independent cities. In other EU countries, the regions have similar areas and populations.

[Scenario description] We examined four scenarios, two of which serve as reference cases (Table 2). Germany is treated as a single bidding zone and IDILES is only used to determine aggregate investments into PtH_2. In the remaining two scenarios, the market split is applied and we allow endogenous investment decisions for PtH_2 in both zones. In both cases, the single bidding zones and market split, we further distinguish between a low and high CO_2 price case. With the two different CO_2 price scenarios, we take into account the uncertainty about the CO_2 price path until 2030.

In further sensitivity calculations, we consider different exogenous allocations of the capacities taken from the optimized reference cases to the north and south zones in the market split cases. This allows us to compare the effect of a market split on the north-south congestion for the exogenously given electrolyser capacities. We consider an equal distribution to both zones, a one-sided distribution to the north zone and a one-sided distribution to the south zone. This results in a total of six sensitivity runs considering both CO_2 price scenarios.

The geographical scope of our scenarios is extended to Europe. For the investment decision, we only allow investments in Germany; hence, in all scenarios we ensure the same initial situation regarding the remaining European countries. The reason for this is that, even if we observe homogeneous political commitment at the European level, the prospective energy systems underly several uncertainties regarding assumed energy transitions. A second important argument is the necessary calculation time. By enlarging the system to Europe, the allowance for (dis-)investments would lead to an enormous time effort. Nevertheless, it might be easier to understand the integration of PtH_2 in Germany without investments abroad.

Table 2: Scenario description

	CO_2-Price	
	75 €/t CO_2	**114 €/t CO_2**
Reference	*Ref_low*	*Ref_high*
Market split	*Split_low*	*Split_high*

Figure 3 shows the German power plant portfolio in 2030. For the scenarios with one bidding zone, the portfolio *DE* is used; the scenarios with two bidding zones use the portfolios *DE_North* in the north zone and *DE_South* in the south zone. Installed capacities in Germany are mainly based on gas-fired power plants (36.4 GW), solar (109.9 GW), and onshore (95.5 GW) and offshore wind (17.3 GW). Other non-renewables (15.8 GW) are smaller scale combined heat and power (CHP)-plants based on oil and gas. Other renewables (6.6 GW) are mainly biomass and municipal waste. Flexibilities consider battery storages (5.1 GW), pump storages (8.4 GW), and electrolysers, which are not included here. The electrolyser capacities differ in the scenarios and correspond to the IDILES results described in Section 4. The German base load is about 688.8 TWh.

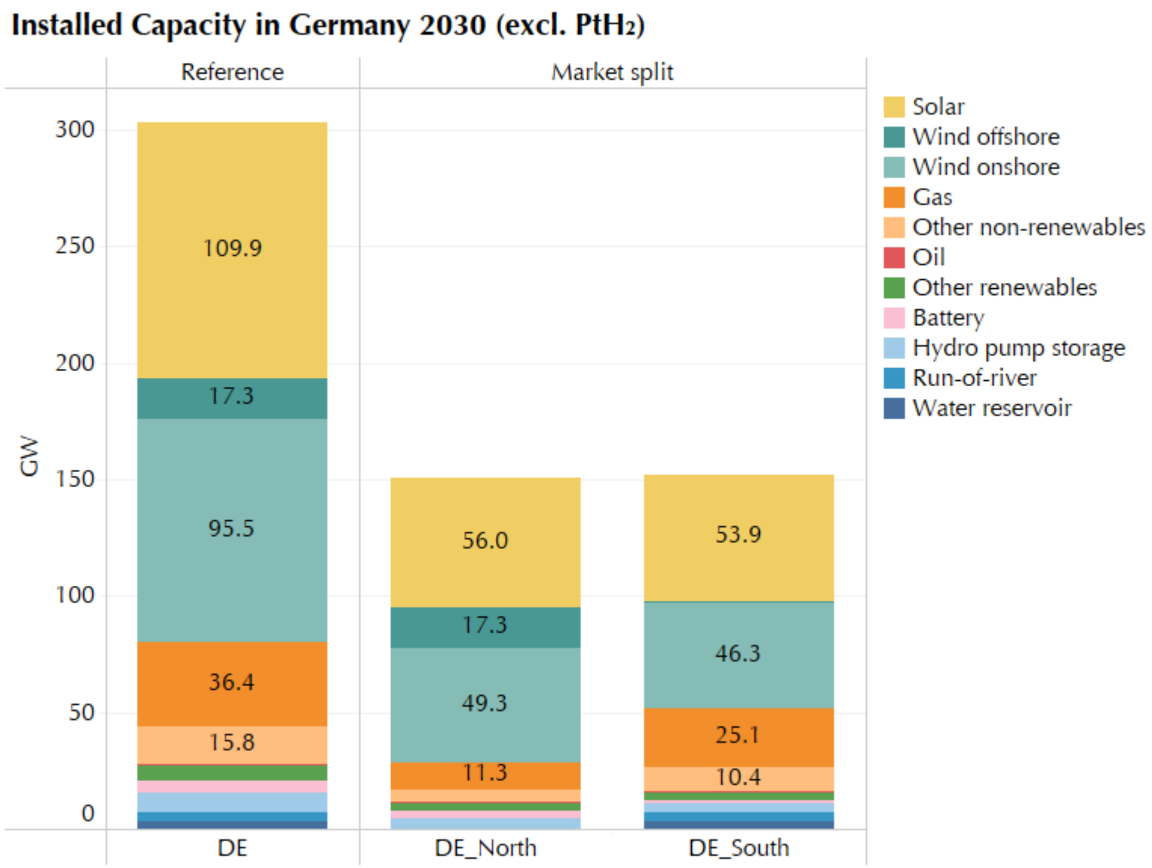


Figure 3: Installed capacities in Germany in 2030 (excl. PtH_2) for all scenarios

4 Results and Discussion

4.1 Impacts on Spatial Investment Incentives

The four scenarios induce different optimal investment decisions in relation to electrolyser capacity in Germany, depending on the market split and the CO_2 price level. Figure 4 shows that the total electrolyser investment under the market split exceeds the investment in the single-zone case by almost double in both CO_2 price scenarios. In the cases with a market split, the electrolyser capacity is entirely allocated to the north zone. Compared to the status quo, no change, and thus no investment, occurs in the south zone. In any case, a higher CO_2 price leads to higher overall electrolyser investments. The installed capacities without market split miss the government's target of 10 GW by 2030 regardless of the CO_2 price level. Both scenarios with market split exceed this target. All investments are only based on market incentives without any subsidies. The results underscore the expected effects from market splitting and CO_2 price variations.

Starting with the impact of the market split, the results show that contribution margins of the electrolysers are higher in the case of a market split within the north zone in comparison to the reference case. This is due to lower electricity prices in the north zone caused by high renewable production and limited NTC between northern and southern Germany. The impact of the CO_2 price indicates that the increasing production costs of conventional power plants lead to even higher overall contribution margins due to their consideration in the merit order.

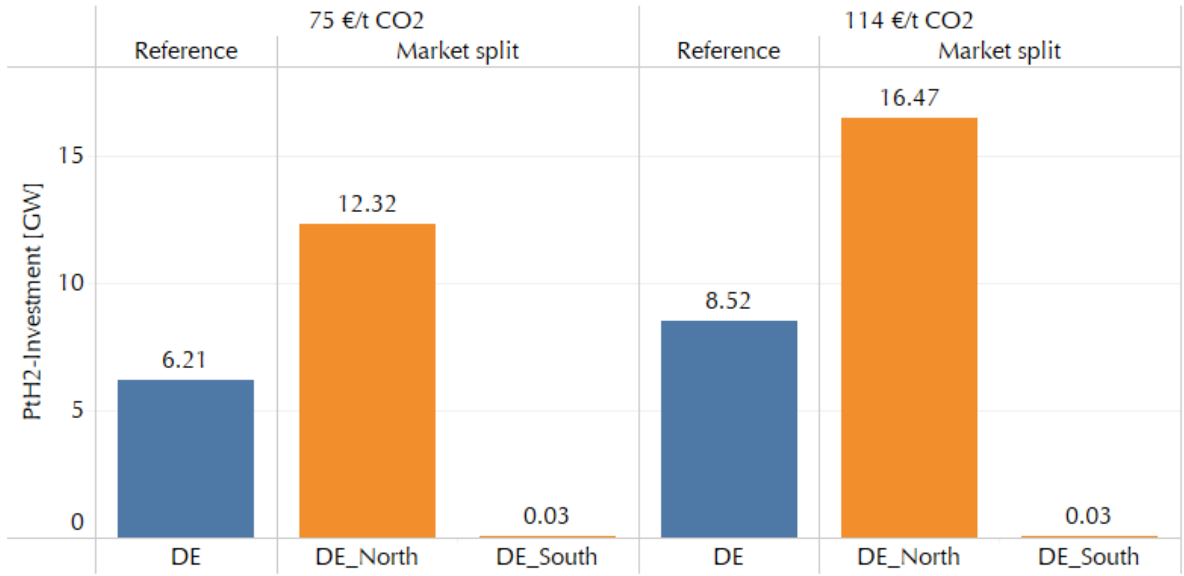
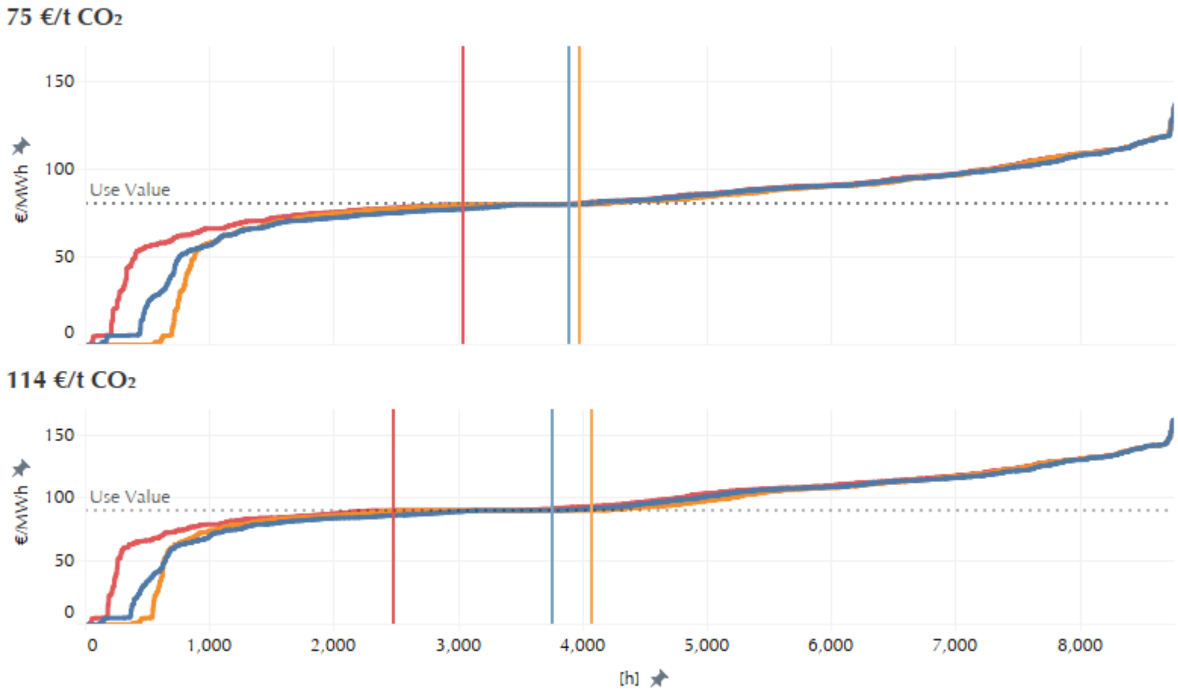


Figure 4: PtH_2 investments

These effects lead to different market prices between the scenarios. Figure 5 illustrates the inverted price duration curve (PDC), the average market prices, and the utilization hours in Germany in 2030. The PDCs for the low CO_2 price scenarios show lower prices in comparison to the high CO_2 price scenarios. This is due to the increased operational costs for conventional power plants using fossil fuels as a result of higher CO_2 prices. This also affects the average price levels. We further see that the price level in the case of a market split is higher in the south zone. This is due to the fact that the share of renewables is higher in the north, while demand is higher in the south and because of the limited NTC between both market zones. Thus, the merit order differs in the north and in the south. In the case with a market split, the average price in the reference case is in between the two zonal prices. Just as we see differences in PDCs in the high-price hours, we also see differences in the low-price hours. The number of hours with prices at zero is much higher in DE_North than in DE_South or DE as the reference case without a market split. This can be explained by higher market driven curtailment in DE_North. The prices do not fall below zero due to the assumption of full market integration of renewables and, thus, no compensation for curtailment. With respect to utilization of the electrolysers, there is a plateau in each graph at a price of 79.94 €/MWh for low CO_2 prices and at a price of 90.31 €/MWh for high CO_2 prices, which reflect the price setting by the electrolysers in one region. These prices correspond to the use values in the respective CO_2 price scenarios. This plateau is much larger in DE_North than in DE for both CO_2 price sensitivities. As previously noted, there are lower prices in the north and higher prices in the south. The lower prices in the north zone incentivize the utilization of the electrolysers, since the prices are below the use value for many hours of the year. Hence, the positive contribution margin leads to the investment decisions, as shown in Figure 4. The utilization hours—marked as vertical bars in Figure 5—of the reference case and the north zone in the market split case are close to each other. In the case of low CO_2 prices, the utilization hours in the reference case amount to 3892 hours and to 3979 hours in the north zone for the market split case. With high CO_2 prices, the difference increases with 3760 utilization hours in the reference case and 4072 hours in the north zone for the market split case. The south zone is neglected due to its low capacities.



Average Prices in €/MWh

75 €/t CO2			114 €/t CO2		
DE	DE_North	DE_South	DE	DE_North	DE_South
79.92	78.99	83.33	94.88	94.50	99.13

Figure 5: Inverted price duration curves, average prices, and utilization hours

4.2 Impacts on Utilization of Electrolysers

As seen in Figure 4, the electrolyser capacity differs depending on the scenario. Consequently, the amount of electricity consumed also differs in the scenarios (Figure 6). Under the selected scenario setting, hydrogen seems to be more economically advantageous in the north zone, if a market split is assumed. While the electrolysers in the north consume 43.41 TWh in the low CO_2 price scenario and 54.86 TWh in the high CO_2 price scenario, the amount in the south zone is close to zero in both cases. In the reference case, the electrolysers consume 22.93 TWh in the case of low CO_2 prices and 29.64 TWh in the case of high CO_2 prices. The number of utilization hours is given in Figure 5. In the case with the Benders decomposition approach, where system costs are minimized, the utilization hours and the consumed amount of electricity by the electrolysers, reflect the system cost minimizing integration of PtH_2 on the operational level. Hence, investments in the electrolysers and the associated utilization of the electrolysers address the total system cost minimization.

Focusing on the sensitivity analysis, given in Figure 6, the results show—in case that the optimal capacities from the reference cases are used for market splitting—that the electrolyser consumption is highest when the capacity is located entirely in the north. It is lowest when capacity is fully allocated in the south and somewhere in between when capacity is equally distributed between north and south. In the case of low CO_2 prices, the market split leads to higher consumption when capacities are equally distributed or completely shifted into the north in comparison to the reference case. In the case of high CO_2 prices, this observation is only true if the capacity is completely shifted to the north zone. The differences in capacities and thus in utilization between an optimized one zonal case—and starting from this point, the distributed capacities for sensitivity analysis—and an optimized case with market split show the missed potential for market ramp-up of electrolysers without market splitting.

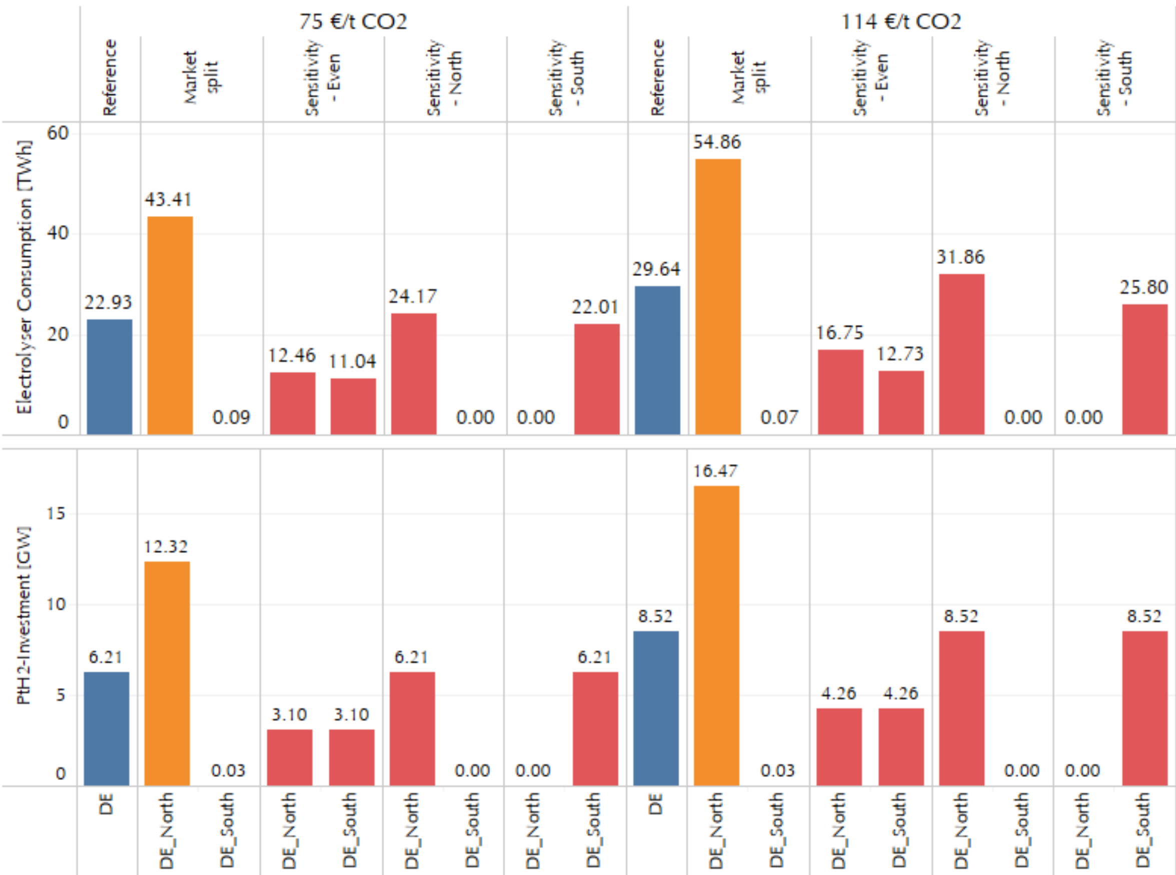


Figure 6: Electrolyser capacity allocation and consumption, including sensitivities

4.3 System Costs Effects

Figure 7 illustrates the savings in operational and total system costs due to the integration of PtH_2. The savings are the difference between the status quo with almost no electrolyser capacity and the version with optimized electrolyser capacities, and are shown for the reference case, the market split case, and the sensitivities. Starting with the operational costs savings, the savings are at least two-times higher for the market split case than the reference case. The comparison of different CO_2 prices shows that higher CO_2 prices further incentivize cost savings due to even higher integration of PtH_2. Overall, the system costs increase, but the market incentives for the electrolysers are even higher due to the interplay of the CO_2 prices and use value. In the market split case, the incentives for investments are given in the north zone, as Figure 4 illustrates. The sensitivity analysis indicates that the highest incentives for integrating the electrolysers are given by complete allocation to the north, while a complete allocation to the south is the most disadvantageous. The sensitivities emphasize the high spatial incentives for the north in the case of a market split. In comparison to the reference case, the capacities used in the sensitivity analysis are not optimal in order to reduce system costs and optimally integrate PtH_2. The optimal exploitation of the PtH_2 potential is given by the market split case. Taking the investment costs for the electrolysers into account, the total system costs savings decrease by the amount of the annualized investment costs. The total costs savings are at least five-times higher for the market split case than the reference case. The differences within the same case—the reference case or the market split case—but with different CO_2 prices increase due to the higher electrolyser investments in the high CO_2 price cases.

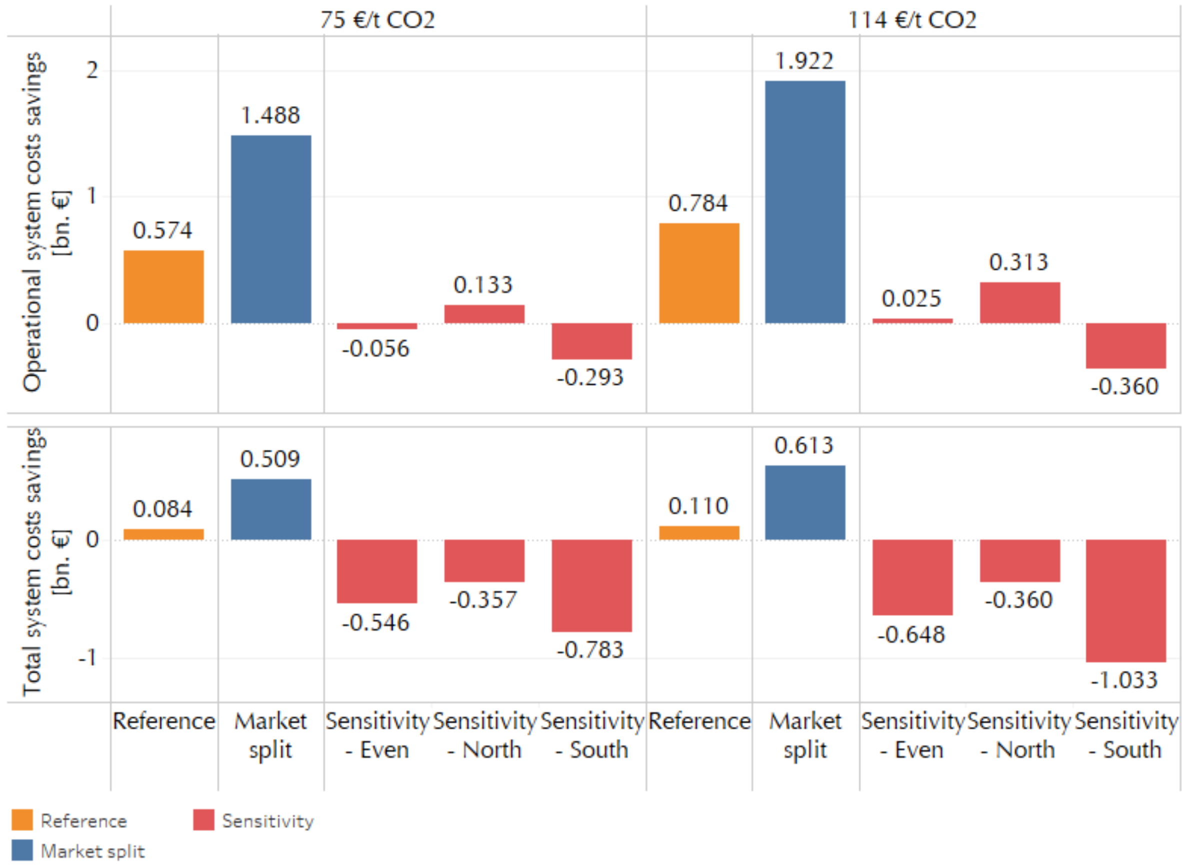


Figure 7: System costs savings in bn. €

4.4 Impacts on Congestion and Renewable Integration

Figure 8 shows the electricity transfer between the north and south zones in Germany in the market split case (here seen in the *Split_low* case). Electricity flows predominantly from north to south, not from south to north. Over the entire year, 87.19 TWh are transmitted from north to south and 2.16 TWh are transmitted from south to north. In 1467 hours of the year, the line from north to south is at its capacity limit. Taking the price information from Figure 5 into account, there are almost continuous transfers from north to south, mainly due to renewable production in the north resulting in a lower price niveaus there.

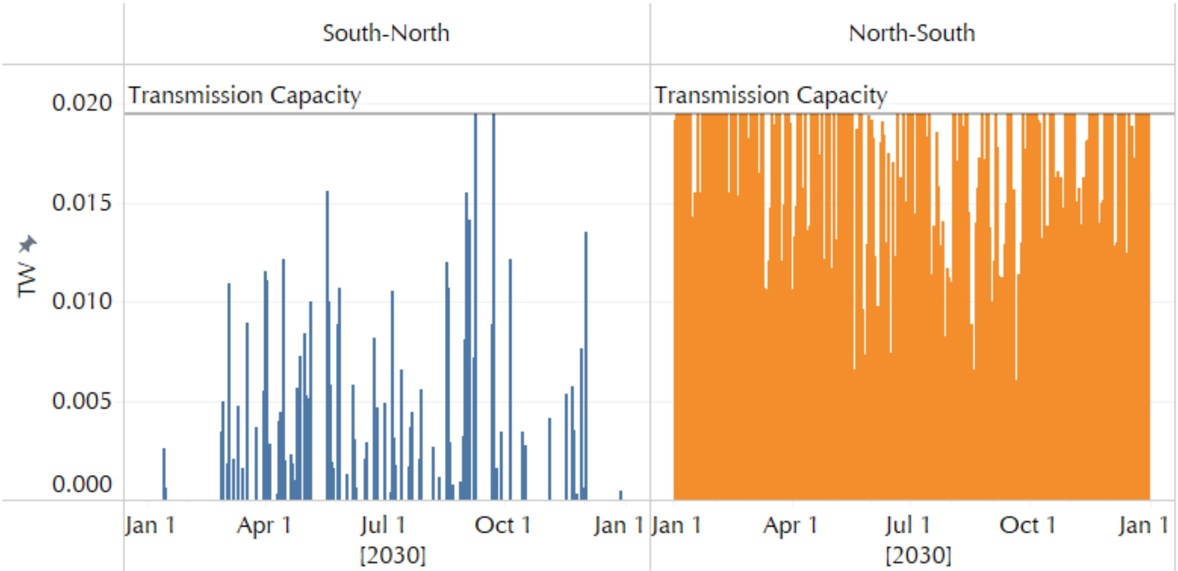


Figure 8: Transmission between the north and south zones – Case Split_low

As seen in Figure 9, the comparison of the initial status quo and the optimized market split cases shows that the amount of exchanged electricity decreases with increasing electrolyser capacity. This can be explained by the provision of flexibility from the electrolysers. The sensitivity runs indicate that the provision of flexibility by the electrolysers is most favorable in the case of complete capacity allocation to the north. This sensitivity has the lowest domestic transfer; thus, it contributes more to avoiding grid congestion. In the case of complete capacity allocation to the south, the domestic transfer is the highest and it also exceeds the status quo. Thus, grid congestion is amplified by inefficient distribution of the electrolyser capacity.

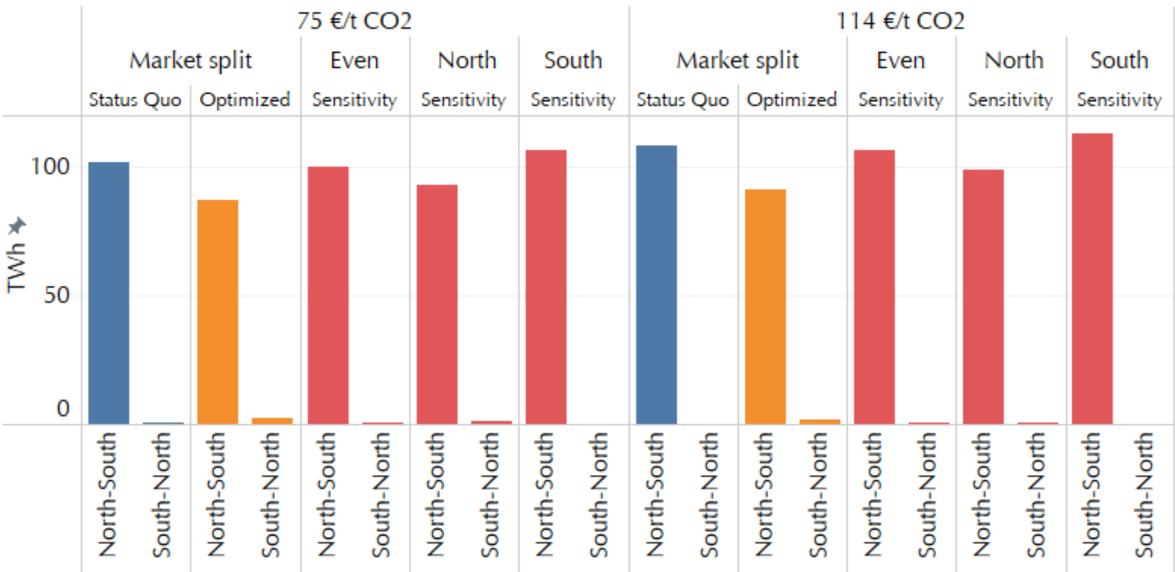


Figure 9: Domestic transit after the market split, including sensitivities

Figure 10 shows the renewable curtailment for the different scenarios in the market split case. The market split cases are shown in the two orange bars representing the curtailment in the status quo iteration and in the optimized iteration. The sensitivities show the curtailment in exogenous capacity distribution. Most of the curtailment takes place in the north; therefore, we neglect the marginal curtailed energy of the south in Figure 10. The curtailment in the north can be explained by higher renewable production but lower demand and transfer capacity restrictions. Comparing the status quo iteration with the optimized iteration in the market split case, the curtailment decreases due to the provision of flexibility by the electrolysers. The curtailment declines as the CO_2 prices increase due to even higher provision of flexibility by the electrolysers. This is shown in Figure 6 where the electrolyser capacities and the consumption increase with increasing CO_2 prices. Again, the results indicate that market split and the higher CO_2 prices incentivize the integration of PtH_2. The sensitivities show the lowest curtailment for the complete capacity allocation to the north and the highest curtailment in case of a complete capacity allocation to the south. Here, increasing CO_2 prices also result in lower curtailment, but with a much lower effect in the case of the complete capacity allocation to the south, due to less renewable production and higher demand.

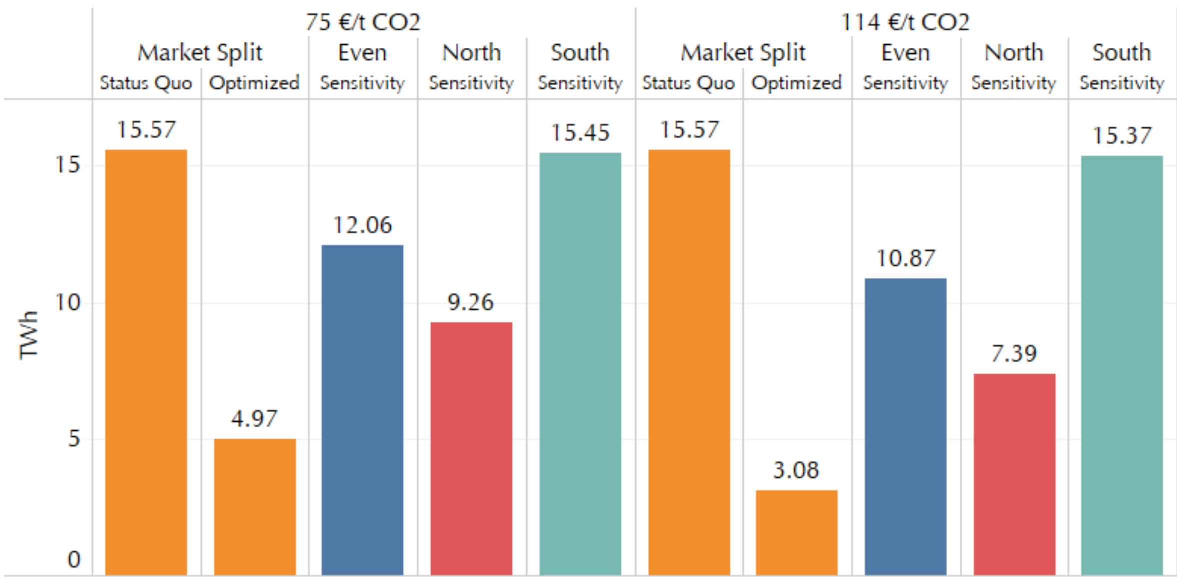


Figure 10: Renewable curtailment in Germany (only for the north zone)

5 Conclusions and Policy Implications

The results indicate spatial incentives for PtH_2 integration through market splitting. With a market split, we observed high investments in the electrolysers in the north zone due to higher market incentives compared to the south zone. This is due to the different price levels caused by scarce transmission capacities and high renewable generation in the north. While the investments were purely driven by market incentives in both the reference case and the market split case, a market split spatially incentivizes more efficient investments. This resulted in a higher integration of PtH_2 in the market case in comparison to the reference case. Overall, there is no identified need for subsidies for PtH_2. In the same way as the investment decision is spatially incentivized by market splitting, the electrolyser utilization is also incentivized. Compared to the reference case as one zonal market, the domestic production of hydrogen is further supported by market splitting. Here, we observed even higher installed capacities and higher electricity consumption. The results of the market split also reveal the electrolysers' role as a flexibility provider. While the results show high volumes of curtailed energy in the status quo, curtailment is reduced due to PtH_2 integration in the optimized cases. Hence, the integration of renewables is also supported by PtH_2. The domestic transit between the north and south zones as an indicator for grid congestion is also relaxed due to the effective integration of PtH_2. The results of the market split cases suggest that the integration of PtH_2 is further beneficial for decreasing overall system costs. Increasing the provision of flexibility by higher electrolyser capacities, increases the system costs savings. This effect is reinforced by the market split and the associated incentives for spatially-related investment decisions. With respect to our main contribution, we conclude that the interplay between the electrolysers and market splitting suggest positive effects for the integration of PtH_2 and the electricity system. The grid congestion due to increasing amounts of renewable production, especially in the north, might be limited by the electrolysers as demand-sided flexibility. Hence, at locations with surplus electricity production, the system can be relaxed. Moreover, the applied market split is beneficial for market integration of PtH_2. In conclusion, we propose the following policy implications:

- Market split leads to more efficient integration of PtH_2 as prices indicate scarcity and lead to spatial investment incentives.
- Market incentives are sufficient for the integration of PtH_2; thus, in this scenario there is no need for subsidies.
- The efficient spatial market integration of the electrolysers is beneficial to the system.

The results shown in this paper are based on the assumed data. Thus, we refer to the observed effects rather than absolute results. Aspects that can be investigated in the future include electricity system feedback effects in the form of investments in electricity generation and electricity storage systems as well as the inclusion of hydrogen imports and hydrogen exports. Combining the electrolyser infrastructure with the existing gas transport infrastructure and other transport routes might provide further insights.

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