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1. Introduction

1.1. Motivation

The German energy transition (*Energiewende*) is a significant undertaking aimed at achieving climate neutrality by 2045. This ambitious goal requires fundamental transformation across sectors, a process that involves the replacement of a substantial share of the existing capital stock. In the electricity sector, this includes the decommissioning of conventional power plants and investing into renewable energy sources (RES) such as wind and solar, as well as flexibility technologies like batteries. In the building sector, aging fossil fueled heating systems must be replaced with climate-neutral alternatives.

Given the magnitude of the required investments, it is crucial to coordinate the energy transition in a manner that minimizes costs to society. Efficient coordination means addressing two central questions: First, which technologies should be prioritized, and second, how can the investment in these technologies as well as their dispatch be coordinated efficiently?

In theory, such coordination can be achieved by markets and the resulting price signals. Under ideal conditions — convexity, perfect information, no transaction costs, no (unpriced) externalities, rational behavior — competitive markets can reveal the true marginal costs and benefits associated with investment or technology dispatch decisions. Doing so, they guide decision-makers toward the cost-efficient solutions (Pindyck and Rubinfeld, 2005). However, in the real world these ideal conditions often do not hold — and different challenges arise in different sectors.

In the electricity sector, these challenges include unpriced externalities. European electricity markets already internalize CO_2 emissions from power generation through the European Union Emissions Trading System (EU ETS) as a major externality. The price of CO_2 allowances, set through market auctions, affects the cost structure of electricity generation, thereby embedding the cost of emissions into electricity prices. Still, there is another externality that remains unpriced: increased grid costs resulting from spatial imbalances between generation and demand. Grid constraints and associated costs for congestion management are not reflected in prices, which leads to suboptimal investment in generation technologies and inefficient utilization of grid infrastructure (Weibelzahl, 2017).

In the building sector, examples for challenges include high uncertainty associated with future fuel prices and equipment costs[1]. Additionally, decisions are made by private households who are likely to be imperfectly informed. Furthermore, their decision-making may deviate from that of fully rational agents (c.f. Gillingham et al., 2009).

To overcome these challenges, policymakers must carefully design market structures and regulatory frameworks that can guide investments toward efficient solutions. This requires not only improving the functioning of markets but also considering when and where additional policy interventions, such as subsidies or regulatory requirements, are needed.

This dissertation contributes to the debate on how to achieve a cost-efficient energy transition by exploring open questions related to coordination issues in electricity grids and markets, and the decarbonization of residential heating. The dissertation consists of four chapters. Each chapter addresses a different aspect of the energy transition in an individual paper to which all authors contributed equally:

- The Place beyond the Lines — Efficient Storage Allocation in a Spatially Unbalanced Power System with a High Share of Renewables. Joint work with Amelie Sitzmann and Jonas Zinke. EWI Working Paper 2023-1 and accepted at Energy Economics (Czock et al., 2023).
- Three Zones Fix All? Analyzing Static Welfare Impacts of Splitting the German Bidding Zone under Friction. EWI Working Paper 2025-4 (Czock, 2025).
- A Heated Debate — The Future Cost-Efficiency of Climate-Neutral Heating Options under Consideration of Heterogeneity and Uncertainty. Joint work with Michael Moritz and Oliver Ruhnau. EWI Working Paper 2024-3 and under review at Energy Policy (Moritz et al., 2024).
- Cost and Cost Distribution of Policy-Driven Investments in Decentralized Heating Systems in Residential Buildings in Germany. Joint work with Fabian Arnold and Cordelia Frings. Published in Energy and Buildings, Vol. 327, 2025 (Czock et al., 2025).

The following provides an outline of the individual Chapters (Section 1.2), and discusses the methodological approaches as well as future research (Section 1.3).

[1] C.f. Chapter 4.

1.2. Outline

The Place beyond the Lines - Efficient Storage Allocation in a Spatially Unbalanced Power System with a High Share of Renewables

Chapter 2 addresses grid constraints as an unpriced externality in electricity markets. Specifically, it analyzes coordination issues in a power system with a high share of renewables and spatial imbalances between supply and demand that lead to transmission grid congestion. While grid expansion is restricted in the medium term, storage technologies can potentially increase the power system's efficiency by aligning generation and demand in time and boosting grid utilization — provided they are optimally sited within the transmission network. This chapter uses a theoretical and a numerical model to evaluate the optimal allocation of battery storage within the transmission grid and analyzes the impact of different market designs on battery allocation. The results for a case study on Germany show that batteries can reduce system costs when placed below the north-south grid bottleneck and near solar power. The supply costs in a setting with uniform prices and a random battery distribution are 9.3% higher than in the theoretical first-best benchmark with nodal prices. An optimal allocation of batteries can reduce this efficiency gap by 0.7 percentage points to 8.6% — the remainder of the efficiency gap can be explained by the suboptimal allocation of wind and solar power under uniform pricing.

Although the efficiency gains achieved by batteries seem small, in relation to the cost of battery investments, this corresponds to almost a doubling of the supply cost savings per euro spent. Due to the lack of spatially differentiated investment incentives under Germany's uniform pricing scheme, battery allocation requires additional policy measures. Simple allocation rules such as tying battery siting to solar capacity or explicitly identifying a limited number of suitable sites for capacity auctions can approximate an optimal allocation and can serve as the foundation for such a policy instrument.

Three Zones Fix All? Analyzing Static Welfare Impacts of Splitting the German Bidding Zone under Friction

Chapter 3, too, analyzes coordination issues arising due to transmission grid congestion. Focusing on electricity market dispatch decisions, rather than investment and spatial allocation, it examines the static market and welfare effects of internalizing grid constraints by splitting the German bidding zone. Specifically, it compares a two-zone and a three-zone configuration for a 2030 scenario. Using a state-of-the-art grid and market model with explicit representation of frictions in flow-based market coupling (FBMC) and redispatch, it finds that the investigated two-zone split results in a 1.6% static welfare loss as redispatch cost savings do not overcompensate the negative effect of more transmission constraints in the electricity market. Contrarily, three zones lead to a 4.4% static welfare gain, as redispatch cost decrease further than with two zones and trade between German zones is enhanced due to a reduction of loop flows on interconnectors between Germany's North and South. However, both bidding zone split options lead to significant distributional effects, with higher consumer costs and increased subsidy expenditures for RES, though these effects are less pronounced with three zones. Additionally, welfare effects are sensitive to scenario definition and representation of frictions. Policymakers should carefully assess the uncertain welfare gains against the transition costs of a bidding zone split, while also considering distribution effects and interactions with existing policies such as the RES subsidy scheme. Reducing frictions in redispatch, albeit with new coordination challenges, could potentially achieve similar objectives with lower transaction costs and fewer distributional impacts.

A heated debate - The future cost-efficiency of climate-neutral heating options under consideration of heterogeneity and uncertainty

To tackle climate change, residential heating must become climate-neutral. Which technologies have the potential to achieve this goal in a cost-efficient manner is a complex question, given the heterogeneity of buildings and existing infrastructure, as well as the uncertainty regarding future energy prices and infrastructure costs. **Chapter 4** aims to disentangle this complexity by comparing the future costs of various decentralized and centralized climate-neutral heating options. Using Germany as a case study, the future levelized cost of eleven heating technologies are calculated for different building and settlement types and a wide range of assumptions for uncertain parameters, such as energy prices and grid fees. The results show that electric heat pumps are most often the economical choice within the considered range of inputs. Decentralized heat pumps appear preferable in rural areas, while heating grids with central heat pumps are seemingly equally attractive in more urban areas. Hydrogen boilers would be cost-efficient only in scenarios with low hydrogen prices and, even then, often limited to rural settlements. Heating with synthetic natural gas seems unlikely to be economical across a broad range of plausible assumptions. The results are highly relevant for the ongoing process of municipal heat planning, which mandates municipal policymakers to evaluate local district heating and hydrogen grid expansion options by 2028.

Cost and cost distribution of policy-driven investments in decentralized heating systems in residential buildings in Germany

While the ongoing municipal heat planning process focuses on making centralized infrastructure decisions, Germany already uses policies, such as renewable energy requirements, subsidies, and CO_2 pricing to incentivize investment in specific decentralized technologies on a household level. **Chapter 5** analyzes how these policies influence household decision-making regarding decentralized building energy technology and the resulting costs. The chapter uses a building-level mixed integer linear programming model to determine optimal investments and operation for decentralized technologies across a representative building stock for German residential buildings. The results show that with renewable energy requirements, subsidies, CO_2 pricing, high medium-term gas prices, and moderate electricity price increases, many buildings benefit from early replacement of fossil systems with electric heat pumps, leading to rapid decarbonization. However, the costs of decentralized decarbonization vary widely: some buildings see net savings of up to $4,800$ EUR from 2020 to 2045 compared to a no-policy scenario, while others face substantial costs. For example, single-family homes with recently installed gas or oil systems, where early replacement with heat pumps is not feasible, could incur up to $11,000$ EUR in CO_2-related costs. Residents of multifamily homes with single-story gas heating may face CO_2 costs up to $8,000$ EUR per residential unit due to limited decarbonization options. Policymakers should consider these dynamics when prioritizing buildings for district heating or hydrogen in municipal heat planning or designing CO_2 price revenue recycling mechanisms.

1.3. Methodological Approaches

This dissertation analyzes different coordination issues arising within the German energy transition and employs different methods, each suited to the specific research question of a chapter.

Specifically, **Chapters 2 and 3** address coordination issues arising in electricity markets with a high share of volatile renewable generation and spatial imbalances between supply and demand that lead to transmission grid congestion. They utilize a partial-equilibrium model of the European electricity sector and transmission grid, which simulates electricity markets and the corresponding load flows in a numerical optimization. To enable an interpretation of the optimization results as the outcome of electricity markets, this model relies on several fundamental assumptions: competitive, efficient markets with no transaction costs and rational market participants with perfect foresight. Furthermore, electricity demand is assumed to be inelastic and distributed across Germany exogenously.

The model has been tailored to address the particular research questions presented in each chapter. In **Chapter 2** it is used to model investment and dispatch decisions under different market designs: the rather theoretical first-best nodal pricing benchmark and uniform pricing with a subsequent redispatch. The latter resembles today's market design in Germany. This enables an analysis of efficient battery storage allocation within the German transmission grid and market design and policy challenges associated with achieving an efficient battery allocation. Several limitations should be considered when interpreting the results. First, there are limitations regarding the theoretical nodal pricing fist-best setup, which is used to benchmark different market designs and policies. Nodal pricing means that grid constraints are incorporated in the price formation, revealing information on grid constraints to market participants. In an ideal scenario without frictions, this price formation serves as the first-best benchmark for the efficient coordination of electricity supply, demand, and grid operations. However, in practice, various frictions, such as reduced liquidity, lack of transparency, market power, and increased transaction costs can distort the efficiency of the system. Therefore, the estimated efficiency gains under nodal pricing reflect an upper benchmark. Second, under uniform pricing, grid constraints are not reflected by market prices. Thus, wind and solar power allocation, which affects efficient battery allocation, is only guided by resource quality and regional potential. Compared to reality, spatial incentives from the German subsidy scheme for wind power are neglected. Efficiency losses under uniform pricing are therefore potentially over-estimated.

In **Chapter 3**, the model is applied to model electricity dispatch and redispatch with a detailed representation of the transmission capacity allocation between market zones under FMBC. This enables the analysis of static welfare effects of splitting the German electricity markets into two or three zones under frictions in FBMC and redispatch. It has to be noted that, first, the results are contingent on the chosen representation of frictions in redispatch. Further work is needed to explore the impact of various redispatch modeling approaches on static welfare results. Second, the representation of FBMC employed in this study involves several simplifications, which are common in quantitative studies. Further research should assess the impact of these simplifications on static welfare results. Third, the potentially reduced liquidity in smaller bidding zones and its potential welfare impact remains unexplored and should be addressed in future studies.

To analyze the energy transition of the highly heterogeneous German building stock, **Chapter 4** and **Chapter 5** employ building level models to sets of representative buildings. **Chapter 4** focuses on the uncertainty associated with future costs of climate-neutral heating options given the heterogeneity of residential buildings in Germany and the uncertainty associated with future energy prices. Based on a technical simulation of system sizing and operation, it calculates levelized costs for heating for different climate-neutral heating options over a wide range of assumptions for uncertain or heterogeneous input factors. This allows a systematic analysis of which heating system is cost-optimal under what circumstances. While **Chapter 4** is concerned with determining the target technologies for the building energy transition, **Chapter 5** assesses the impact of existing policies, such as subsidies and renewable energy requirements, which already incentivize specific technologies. To do so, this chapter employs a building-level mixed integer linear programming model, simulating optimal decision-making with regards to investments and operation for decentralized technologies across a representative German residential building stock. Comparing a policy scenario and a reference scenario without policies, it is possible to derive the additional costs and their distribution across residential buildings. The model assumes perfect foresight and rational behavior of households and does not distinguish between building owners (i.e. decision-makers) and tenants (i.e. energy technology users). Thus, it potentially overestimates decarbonization speed, while it underestimates CO_2 costs for households. To analyze the energy transition of the highly heterogeneous German building stock, **Chapter 4** and **Chapter 5** employ building level models to sets of representative buildings. **Chapter 4** focuses on the uncertainty associated with future costs of climate-neutral heating options given the heterogeneity of residential buildings in Germany and the uncertainty associated with future energy prices. Based on a technical simulation of system sizing and operation, it calculates levelized costs for heating for different climate-neutral heating options over a wide range of assumptions for uncertain or heterogeneous input factors. This allows a systematic analysis of which heating system is cost-optimal under what circumstances. While **Chapter 4** is concerned with determining the target technologies for the building energy transition, **Chapter 5** assesses the impact of existing policies, such as subsidies and renewable energy requirements, which already incentivize specific technologies. To do so, this Chapter employs a building-level mixed integer linear programming model, simulating optimal decision-making with regards to investments and operation for decentralized technologies across a representative German residential building stock. Comparing a policy scenario and a reference scenario without policies, it is possible to derive the additional costs resulting from the policies and the cost distribution across residential buildings. The model assumes perfect foresight and rational behavior of households and does not distinguish between building owners (i.e. decision-makers) and tenants (i.e. energy technology users). Thus, it potentially overestimates decarbonization speed, while it underestimates CO_2 costs for households.

Additionally, by employing building-level models, **Chapter 4** and **Chapter 5** cannot model the interrelation between building decision-making and the resulting demand, and energy prices (including infrastructure costs). In both Chapters, sensitivity analyses are performed to explore the impact of this limitation.

In addition to this discussion, each chapter provides a detailed explanation of the methodologies employed, highlights their limitations, and suggests possibilities for future research.

2. The Place beyond the Lines - Efficient Storage Allocation in a Spatially Unbalanced Power System with a High Share of Renewables

2.1. Introduction

As countries strive for climate neutrality, they aim for high wind and solar power penetration rates. Wind and solar are intermittent, so temporal congruence with demand is not guaranteed. Additionally, resource quality varies across regions, which may lead to a spatial imbalance between supply and demand or extensive transmission requirements that exceed the capacity of existing grid infrastructure. Efficient coordination of investments in wind and solar, as well as in transmission grid expansion and power system flexibility, can mitigate these challenges and decrease system costs. Storage technologies, such as electric batteries, provide such power system flexibility. They can address temporal imbalances by shifting generation and load and reduce spatial imbalances by improving network utilization if allocated accordingly. Whether such an allocation is achieved ultimately depends on the market design. Under nodal pricing, allocation incentives are set by market prices. Such incentives do not exist in uniform pricing systems.

This paper analyzes investment in storage technologies in both a nodal and a uniform setting. We focus on a rapidly changing, spatially unbalanced power system, i.e., where solar and wind capacity expansion is fast, but grid expansion is slow. By applying a stylized, theoretical, and a numerical investment and dispatch model, we answer the following three research questions: Firstly, where in the transmission grid should batteries be allocated? Secondly, how important is storage allocation for the system's efficiency? Thirdly, can specific allocation rules approximate the optimal storage allocation under uniform pricing?

The importance of storage allocation is first illustrated using a theoretical two-node, two-time-step model that stylizes the characteristics of a spatially unbalanced power system. This model enables us to show fundamentally that storage capacity can increase line utilization depending on its location. We show that both an allocation before or behind a grid bottleneck can be efficient. Which allocation rule dominates crucially depends on the temporal relationship between the volatility pattern of renewable generation, the demand structure, and available transmission capacity. Naturally, the complexity of the allocation question increases as soon as more than two nodes and time steps are considered. Therefore, we provide a comprehensive numerical model to investigate optimal storage allocation in a system with multiple technologies and a detailed grid representation. We use the German electricity system as a case study.

Already today, Germany exhibits characteristics of a spatially unbalanced electricity system. Under the single bidding zone, i.e., uniform pricing, wind generation is dominantly allocated in northern Germany on the shore of the North and Baltic Seas, while electricity demand is historically centered in the south and west of Germany, which is more densely populated and industrialized. As a result of this spatial mismatch, the volume and costs of network congestion measures have risen and are likely to increase further, given Germany's latest renewable capacity targets.

To investigate the optimal allocation of storage and identify suitable allocation rules to coordinate storage investments, we use a linear optimization market and grid model that endogenously determines the allocation of storage and renewable generation technologies. The analysis focuses on short-term, utility-scale battery storage systems, assuming that assets are fully dispatched by market signals and can be used in redispatch. The model computes a closed-form solution to the investment and dispatch optimization problem while considering a high spatial resolution. We use the results from modeling a nodal setup with consideration of transmission constraints as a theoretical first-best benchmark. This allows benchmarking battery allocation under a uniform setup without consideration of transmission constraints in the investment problem, similar to the current German market design.

The results are two-fold: First, we find that a significant welfare gap results from the inefficient allocation of renewables under uniform pricing. Even with optimal battery allocation, supply costs in the uniform pricing setup are 8.6% higher than under nodal pricing. Second, the results of the numeric simulation confirm the importance of local demand, renewable feed-in volatility, and availability of the grid infrastructure for optimal battery allocation. Especially solar generation, which has a daily generation pattern that matches the batteries' short-term shifting abilities, is a key driver for an efficient allocation. If batteries are randomly distributed, the efficiency gap compared to the nodal benchmark increases to 9.3%. In other words, an optimal allocation of batteries can reduce this efficiency gap by 0.7 percentage points. Although this seems small in comparison to the efficiency gap caused by inefficient allocation of renewables, in relation to the cost of battery investments, this corresponds to almost a doubling of the supply cost savings per euro spent. The supply cost savings are realized in redispatch, where the location of batteries is crucial.

In the current system in Germany, such an optimal allocation is not achieved because spatially differentiated investment signals are not available under uniform pricing. However, with the help of an additional policy instrument, location-specific information could be made transparent to provide a reference point for allocating batteries in a system-beneficial way. To explore possible allocation rules that can set the basis for such a policy instrument, we model different allocations and evaluate their effectiveness. While we do not present a fully developed policy tool, our results show that simple rules can closely approximate an optimal allocation: Optimally placed batteries reduce supply costs by 1.5% compared to a uniform setup without batteries. Tying battery allocation to solar generation (1.3%) or limiting capacity auctions to a predefined number of nodes (0.7%-1.5%) achieve nearly the same result. These findings suggest that even in the absence of location-specific price signals, targeted policy interventions can guide battery investments toward a more efficient spatial distribution.

2.2. Literature review

Several publications have touched upon the role of storage in spatially unbalanced power systems. Newbery (2018) argues that storage can increase grid utilization, thus decreasing system imbalances. However, literature is scarce regarding theoretical analyses of fundamental determinants of efficient storage allocation within transmission grids. Neetzow et al. (2018) analyze the interplay of storage facilities and grid expansion in an analytical setup and show whether these options are complements or substitutes, which critically depends on the characteristics of transmission congestion and the alignment of marginal generation costs between the regions or nodes. Weibelzahl and Märtz (2018) propose a simplified three-node model to examine the effect of storage on the optimal definition of price zones and highlight the additional complexity that storage brings into the system.

Predominantly, the current literature is based on more complex, numerical studies considering specific countries or regions. Many of the studies focus on the deployment of storage in uniform price systems (e.g. Abrell et al., 2019, Schill and Zerrahn, 2018, Zerrahn and Schill, 2017). These papers analyze the possibilities of using storage to balance the temporal volatility of renewables but do not include a detailed grid representation. Thus, these papers cannot analyze questions of spatial allocation. Others consider multiple countries and transmission grid connections between them. For example, Schlachtberger et al. (2017) and Brancucci Martínez-Anido and de Vries (2013) apply numerical models of the European power sector for scenarios with (nearly) 100% renewable power generation in the European power system. They confirm the analytical finding of Neetzow et al. (2018) that storage and grid expansion (between countries) can be both complements and substitutes. Furthermore, Schlachtberger et al. (2017) and Bussar et al. (2014) find that batteries are suitable for smoothing solar power generation, while hydrogen storage capacities and grid expansion are suitable for integrating wind power generation.

To model spatial allocation within countries and to derive market design implications, a representation of intra-country transmission grid constraints is crucial.

Such an analysis is, for example, carried out by Schmidt and Zinke (2023) for the case of wind generation allocation in Germany in 2030. Comparing a nodal and a uniform pricing system, they show that the curtailment of wind energy in a nodal pricing system declines to one-third of its value under uniform pricing, and locations of wind power plants shift from the northwest coast to other areas in Germany. Hence, the authors find that grid utilization is improved due to a broader spatial allocation of wind power plants, and overall system efficiency increases. Similarly, vom Scheidt et al. (2022) investigate differences between a nodal and a uniform pricing system in Germany, focusing on the integration of hydrogen and system-optimal locations of electrolyzers in 2030. The authors find that under nodal pricing, locations shift from regions with high hydrogen consumption to regions with high electricity production, and prices for hydrogen are lower under nodal pricing. They further find that in 2030, under uniform pricing, electrolyzers impose additional congestion management costs of 11% compared to a scenario without electrolyzers which underpins the necessity for a spatially coordinated investment in the upcoming decade in Germany. Lindner et al. (2023) analyze the impact of batteries used as grid boosters or virtual power lines and place them at two exemplary nodes in the north and south of Germany. They find that batteries, used as grid boosters or virtual power lines in the transmission grid, reduce grid congestion and curtailment volumes. Similarly, Bauknecht et al. (2024) analyze the effects of various decentralized flexibility options on the German transmission grid and show their potential to reduce congestion. However, the spatial distribution is exogenously determined and large-scale batteries are not considered in their analysis. Cebulla et al. (2017) and Babrowski et al. (2016) determine the optimal spatial allocation of storage endogenously. Cebulla et al. (2017) use a model of the European power sector in 2050 with a simplified representation of intra-country transmission grids and confirm that batteries can fulfill multiple functions within the power system. Batteries facilitate intra-day balancing by smoothing solar generation patterns, contribute to managing seasonal wind power variability - though additional long-term storage is required - and enhance overall system efficiency in scenarios where grid expansion is delayed. Battery allocation closely correlates with the allocation of renewables, especially solar power. Babrowski et al. (2016) apply a more detailed grid model of the German transmission grid to a 2040 scenario. They find a high amount of battery storage in the northwestern coastal region, mainly to balance the feed-in from offshore wind farms. In addition, large storage capacity is found in the western region near transmission bottlenecks, relieving grid congestion. However, Cebulla et al. (2017) and Babrowski et al. (2016) optimize storage allocation without touching upon market design issues such as missing allocation signals for storage under uniform prices.

Closest to our analysis is literature on efficient incentives for spatial allocation of flexibility assets. Ambrosius et al. (2018) investigate the effects of different market designs on investment incentives for flexible demand in the German industry in various scenarios under nodal and uniform pricing. They construct a multi-stage equilibrium model for endogenous generation capacity investments and network expansion. Various outcomes under nodal and uniform pricing are examined in different scenarios. The authors find that welfare increases and the expansion of conventional generation capacity decreases in the scenario with optimal locational investment as fewer dispatchable power plants are needed to meet peak demands in certain regions. Göke et al. (2022) analyze the substitutability of grid expansion and a well-coordinated investment into generation and storage technologies in a (hypothetical) fully renewable German electricity system. The authors compare different market design options and find that a first-best solution can be well approximated if the current planning approach also considers storage for congestion management. They further show that shifting the location of renewables has no significant effect because the available area potentials have to be exploited almost entirely and there are hardly any optimization possibilities left. However, both papers use a simplified transmission grid representation with 16 and 32 zones, respectively.

Research gap and contribution

Reviewing current literature reveals a lack of systematic analysis of optimal storage allocation and market design implications. Consequently, our paper seeks to bridge the gap between existing publications that address storage, grid issues, or market design as individual issues in power systems with high shares of wind and solar. We contribute a fundamental analysis of storage allocation in a simplified model and verify and expand our findings by employing a numerical electricity market and detailed grid model with endogenous storage allocation in light of the current conditions in Germany. Analyzing storage allocation in a uniform setting and a first-best nodal benchmark allows us to translate the insights from our integrated analysis into policy suggestions.

2.3. The economic rationale for storage allocation

This section introduces a model with two nodes and two time steps to analyze determinants of cost-optimal spatial allocation of storage in a spatially unbalanced transmission network. Generally, electrical storage technologies can shift electricity supply between different points in time.

Depending on their allocation in the grid, storage can use its temporal shifting potential to increase network utilization and thus reduce spatial imbalances. For illustration, consider the following:

Assume a weather-dependent, renewable generation technology in node R, for example, a wind or a solar generator g_{res}, with constant zero marginal costs $c_{res} = 0$. Renewable generation is stochastic and can take two possible states, res_{low} and res_{high}. Demand d is allocated in node D and can also take two possible states d_{low} and d_{high}. For simplicity, demand and renewable availability are assumed not to be correlated, and renewable generation meets demand when both are in the same state, i.e., $res_{low} = d_{low}$ and $res_{high} = d_{high}$. For the possible combinations of either res or d in the two time steps, we distinguish between a *volatility* and a *no volatility* case. In the *volatility* case, the levels of res or d fluctuate across time steps t. Conversely, in the *no volatility* case, res or d remain constant across both time steps.

Further, we consider a peak-load technology g_{peak} at node D, with constant marginal costs $c_{peak} > 0$ and enough capacity to serve the demand in each time, i.e., $\overline{g}_{peak} >= d_{high}$.

Both nodes are connected by a transmission line l with line capacity $d_{low} < \bar{l} < d_{high}$. Hence, if both demand and generation in node R are high, node D could still not be fully supplied by the renewable generation technology due to a grid bottleneck. The model is illustrated in Figure 2.1.

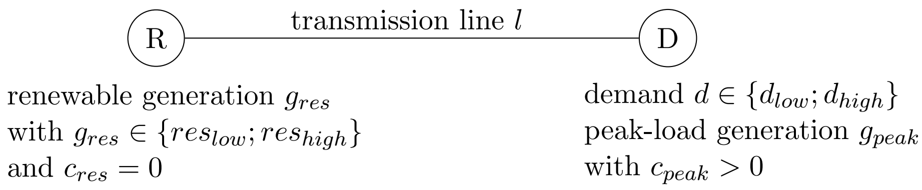


Figure 2.1.: Two-node example

We consider two time steps t_1 and t_2. Combining renewable generation and demand in all its possible states yields eight different cases, shown in table 2.1.[2]

Table 2.1.: Possible combinations of renewable generation and demand in both time steps

	Description	t_1	t_2	Allocation rationale
case 1	no volatility	res_{high}, d_{low}	res_{high}, d_{low}	no storage
case 2	no volatility	res_{high}, d_{high}	res_{high}, d_{high}	no storage
case 3	volatility in generation	res_{high}, d_{high}	res_{low}, d_{high}	storage in R
case 4	volatility in both	res_{high}, d_{low}	res_{low}, d_{high}	indifferent between R and D
case 5	volatility in generation	res_{high}, d_{low}	res_{low}, d_{low}	no storage
case 6	volatility in demand	res_{high}, d_{low}	res_{high}, d_{high}	storage in D
case 7	volatility in demand	res_{high}, d_{high}	res_{high}, d_{low}	no storage
case 8	volatility in both	res_{high}, d_{high}	res_{low}, d_{low}	no storage

Storage s can either be built in node R or D and comes without any investment costs. We further assume no storage losses or other variable costs in addition to charging costs, such that $c_s < c_{peak}$ when storage is charged with renewable energy. For simplicity, we assume that storage power (charge and discharge) capacity equals supply and demand states res_{high} and d_{high}. Furthermore, storage

[2]We do not consider combinations in which renewable generation is low in t_1 as storage is per se useless in these cases.

volume capacity $\overline{s}_{power}$ is sufficient to store at least one period of full charging, i.e., $\overline{s}_{volume} \geq \overline{s}_{power}$. Finally, storage is assumed to be empty in t_1.

By definition, storage is only useful if there are fluctuations in the system, either in renewable generation or demand. If renewable generation is high in both time steps and demand does not fluctuate either, the transmission line l is already used at capacity and peak generation is minimized. Hence, storage has no benefit to the system as a whole, which holds for cases 1 and 2.

If demand fluctuates and transmission line l is not utilized in t_1 or t_2, temporal shifting becomes useful. Consider the case that renewable supply is high in t_1 and low in t_2 and demand in node D is high in both time steps (case 3). Because there is a transmission bottleneck in t_1, storage could be used to store excess renewable generation $res_{high} - \overline{l}$. In t_2, the stored energy can be released and transmitted to node D, as transmission line l is not utilized because generation is otherwise low. Storage has to be allocated at the generation node R to do so, as l is fully utilized in t_1 when the storage is charged. A similar effect occurs, if demand is low in t_1 and high in t_2 (case 4). In this case, however, the location does not matter. Without storage, line l is not utilized at capacity in either time step. Thus, storage can charge regardless of whether it is allocated at node R or node D. In case 5, where demand is low at both times, no storage is needed because both renewable generation and grid capacity are sufficient to meet demand at both times.

If the renewable generation is high at both times, the benefit of storage depends solely on the demand profile. In case 6, where demand is low in t_1 and high in t_2, storage capacity equal to $\overline{s}_{power} = \overline{l} - d_{low}$ is built in node D to use renewable generation in t_2 instead of the more expensive conventional generation. In cases 7 and 8, where res_{high} and d_{high} coincide, again, temporal shifting has no benefit.

Main findings and generalization

The model demonstrates that storage can decrease supply costs by increasing line utilization and that storage location is crucial to unlock said system benefits. The results suggest that storage can be optimal either before or behind a grid bottleneck. In the simple setup, the optimal location depends on the volatility of the underlying demand and generation profiles. Thus, storage is allocated where volatility is higher. In practice, however, the underlying profiles are stochastic and exhibit more time steps, i.e., a sequence of the individual cases discussed above. When combining the cases into a sequence, the strict dominance of an allocation case ceases to exist, meaning that one of the cases could prevail or storage capacity could be split between the two nodes.[3]

Furthermore, the complexity of the model and the underlying relationships increases as soon as more than two nodes and technologies with different characteristics are considered. Even in the very simple model setup with only two nodes and two time steps, the storage allocation depends on the parametrization of generation and demand volatility. To decide where storage is allocated optimally, it is thus necessary to use a well-parametrized and numerical real-world model.

2.4. Methodology and input data

2.4.1. Model framework

We employ an extended version of the investment and dispatch model SPIDER initially developed in Schmidt and Zinke (2023). SPIDER is a model of the European power sector that considers a detailed depiction of the German transmission grid.[4] The model invests in new power plants and dispatches generation capacities such that the net present value of the variable and fixed costs is minimized.

Demand, which means the structure, spatial distribution, and level, is assumed to be inelastic, i.e., not adjusting to prices. The model relies on the assumption of perfect markets and no transaction costs. Thus, the competition of profit-maximizing symmetric firms corresponds to the model's cost minimization of a central planner.

We set up a linear optimal power flow problem (LOPF) to approximate the inner-German transmission grid infrastructure. To keep the problem linear, DC power flow constraints approximate non-linear AC power flow restrictions. Thereby, the model neglects grid losses and reactive power (c.f. van den Bergh et al., 2014). The implementation of DC power flows is based on the cycle-based Kirchhoff formulation, which has been proven to be an efficient formulation (c.f. Hörsch et al., 2018). Network investments are assumed to be exogenous, which is valid for the 2030 time horizon due to the long approval and construction times. European regulatory authorities usually review and approve grid expansion projects 10 to 15 years in advance (c.f. Bundesnetzagentur, 2019).

[3] With a longer sequence of time steps, also the assumption regarding the volume factor of storage $\frac{\bar{s}_{volume}}{\bar{s}_{power}}$ becomes more relevant than it is in the two-time-step example. The volume factor determines the maximum duration of temporal shifting. Different volume factors mean that different parts of a stochastic demand and supply pattern can be exploited, thus also potentially affecting efficient allocation.

[4] For a thorough description of the underlying model and its characteristics, the reader is referred to Schmidt and Zinke (2023).

In addition to the initial model of Schmidt and Zinke (2023), in this paper, SPIDER is extended to allow for endogenous investments in storage as well as solar power capacities. The model optimizes the allocation of storage, but the ratio of maximal charging power (hereafter referred to as capacity) and stored energy (hereafter referred to as storage volume) is set exogenously. The key formulation of the cost minimization problem and the storage constraints are given in A.2.

Modeling a detailed representation of grid constraints and endogenous investments in generation and storage is a computational challenge. As in Schmidt and Zinke (2023), the model is subject to several limitations: As mentioned above, investments in transmission grid lines are exogenous assumptions. Ramping and minimum load constraints are approximated to avoid a mixed-integer optimization and the model does not include combined heat and power plants. Further, the model abstracts from uncertainty and assumes perfect foresight.

2.4.2. Assumptions and data

The regional focus of the model is Germany, with a spatial resolution at transmission grid node level, i.e., 220 kV to 380 kV voltage levels. The depiction of the transmission grid is based on grid information from multiple sources, including Matke et al. (2016) and 50Hertz et al. (2019). Grid extensions follow the German 2030 grid development plan, which was reviewed and approved by the German grid regulator (c.f. Bundesnetzagentur, 2019).

While the German transmission grid is modeled for 2019 with 380 nodes and 606 lines, Germany's neighboring countries are depicted as singular nodes without intra-country grid restrictions. The model includes interconnectors to as well as between neighboring countries, which are approximated via net transfer capacities (NTC) based on ENTSO-E (2020a).

The regional scope and the depiction of the German transmission grid are visualized in Figure 2.2.

The model covers the years 2019, 2025, and 2030. Each year is represented by 12 representative days at hourly resolution. We derive the representative days by using k-medoids clustering with respect to residual load (c.f. Kotzur et al., 2018). The model results are scaled to a full year by weighting the representative days by the number of days within the respective cluster.

Our numerical case study focuses on the year 2030. For our case study, we parameterize the storage technology as large-scale electric batteries with a capacity-to-volume ratio of 4h. The batteries participate in the wholesale market and may be subject to redispatch measures (in the uniform setting).[5] B.1 discloses further

[5] In practice, this does not apply to small storage systems such as photovoltaic systems or storage for electric vehicles designed to increase self-sufficiency.

assumptions on technology parameters, demand development per country as well as fuel prices.

Existing power plant capacities and their distribution across Germany are derived from data provided by the German regulator Bundesnetzagentur.[6] Power plants are distributed via their postcodes to the nearest transmission grid node. The future distribution of offshore wind farms is based on 50Hertz et al. (2019).

Capacity development at the national level is exogenous and follows the *National Trends* scenario in ENTSO-E (2020a) for all countries except Germany. For Germany, the assumed capacity development reflects the legal and political situation. Wind and solar expansion follow the current legal targets[7]. The legislation does not include a specific capacity target for batteries in 2030. Instead, aggregated battery capacity is an assumption based on *Scenario B* from the 2037/2045 grid development plan (50Hertz et al. (2022)).[8] Table 2.2 shows the assumed expansion of wind, solar, and battery capacities in Germany.

Table 2.2.: Assumed development of installed wind, solar and battery capacities in Germany

[GW]	2019	2025	2030
Wind Onshore	53.4	65.4	115.0
Wind Offshore	7.5	14.3	30.0
Solar	49.2	105.2	215.0
Batteries	0.0	5	15.0

[6] Conventional power plants are based on the power plant list (Bundesnetzagentur, 2020a) and renewables on data from the *Marktstammdatenregister* (Bundesnetzagentur, 2020b).

[7] Specifically the *The law for the development and promotion of offshore wind energy*, German: WindSeeG and the *Law on the Expansion of Renewable Energies*, German: EEG

[8] In a sensitivity analysis, our results prove robust for deviating total battery capacities of 5, 10, and 20 GW, respectively (see A.4.2).

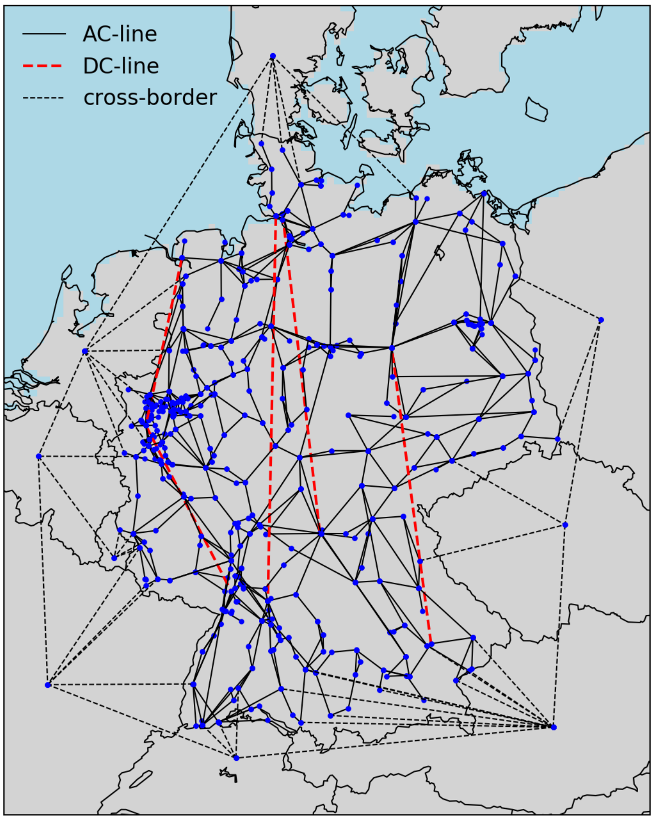


Figure 2.2.: German transmission grid and NTC connections to neighboring countries

The phase-out of German nuclear, lignite, and coal power plants is implemented according to the path defined in the Act to Reduce and End Coal-Fired Power Generation (KAG, 2020). In addition, the announced phase-out of lignite-fired power generation by 2030 is considered for the state of North Rhine-Westphalia (BMWK, 2022b). We assume that the electricity market triggers sufficient investments into backup power plants to meet demand at all times. The location of the required gas capacities is efficiently determined in the nodal setting and fixed for all model runs.

The regional allocation of onshore wind, solar, and battery storage capacity is determined endogenously. Therefore, their regional allocation follows the economic rationale of the considered model setup (see 2.4.3) while considering distributions of determining factors such as demand and resource quality. Since the total installed capacities are the same in all settings examined, the efficiency of regional allocation alone determines the differences in electricity supply costs.

Demand time-series for neighboring countries are based on hourly national demand in 2014, according to ENTSO-E (2020b). The German demand is distributed to the nodes similar to the approach in 50Hertz et al. (2019): Based on sectoral demand shares on the federal state level (c.f. Länderarbeitskreis Energiebilanzen, 2020), household demand is distributed onto nodes proportionally to population shares. The distribution of industry and commercial demand reflects the regional distribution of gross value added for the respective sectors (c.f. EUROSTAT, 2020)). The demand time series are synthesized in a bottom-up approach using sector and application-specific standard load profiles, which reflect 2014 as a calendar and weather year.

The intermittency of renewable feed-in is modeled via weather-dependent hourly regional feed-in potential. The time series for onshore wind in Germany and solar generation are based on high-resolution reanalysis meteorological data from the COSMO-REA6 model. For onshore wind, the conversion of wind speeds to regional feed-in data is based on Henckes et al. (2017). For solar generation, solar radiation was converted to regional feed-in potential as described by Pfenninger and Staffell (2016a). Data for Germany's neighboring countries and German offshore wind power is provided by Pfenninger and Staffell (2016a) and Pfenninger and Staffell (2016b).

2.4.3. Nodal and uniform setting, allocation rules, and benchmarking

The model framework is applied to simulate investment and dispatch decisions under two different settings: nodal and uniform. Each transmission grid node constitutes a market in the nodal setting, and grid constraints are considered within the price formation. When grid constraints are binding, prices differ between nodes. In the case of new investments, these spatially differentiated price signals and hence, transmission bottlenecks are considered in siting decisions. Without any friction, the nodal setting represents the first-best configuration for efficient coordination of power generation investments, dispatch, and the grid.

Germany employs a uniform pricing approach. Uniform pricing relies on larger market areas or zones, usually defined by a country's national borders. Under uniform pricing, physical constraints concerning power flows within a market area are not considered in the market clearing. As a result, the scheduled dispatch after market clearing may violate physical grid restrictions and require curative redispatch measures carried out by grid operators. As grid restrictions are not reflected in the market, prices within a market area are the same. We model a uniform setting where transmission bottlenecks are neglected. As a result, coordination between generation investment, dispatch, and the grid is missing. Consequently, in the uniform setup, siting decisions for wind and solar are guided by resource quality so that new facilities are primarily built in areas where meteorological conditions allow a maximum yield. Other generators, including batteries, are indifferent to siting in the uniform setup.[9] This setup

[9]We neglect additional factors that might impact siting decisions, such as additional policies or locational factors that relate to the preference of individual investors.

represents the uniform pricing market design currently in place in Germany in a simplified way.

Hence, the two setups differ regarding the amount of information available or, more specifically, in terms of the consideration of transmission constraints. In the uniform setting, a subsequent dispatch run considering the DC power flow reveals whether the scheduled dispatch with given investment decisions violates grid constraints, i.e., whether a redispatch is required. The difference in supply costs between the initial dispatch and the subsequent redispatch run is considered the resulting redispatch cost.[10]

We quantify efficiency losses of the uniform setting by comparing total supply costs with the nodal first-best benchmark. The redispatch costs result from the variable costs of the generation units, whereby variable costs of zero are assumed for renewables and storage. Capital costs can be neglected since the total installed capacity is the same in each setting.

Assuming that the uniform pricing system is politically desired and will be maintained in Germany, location-specific information could be made transparent with the help of an additional policy instrument that provides a reference point for a system-beneficial allocation of storage capacities. To get insights on how to design this policy instrument, we use the numerical model to analyze different allocation rules for storage investment in an otherwise uniform setting. Thereby, we focus on allocation rules that coordinate the storage allocation isolated from other technologies. Specifically, we test for *heuristic* approaches and *explicit* allocation rules.

Heuristic approaches, on the one hand, allocate storage capacity based on a reference distribution. We select the heuristics based on an analysis of drivers for optimal storage allocation. A similar instrument to such a heuristic is used in the capacity auction for wind power generation. To achieve a broader capacity distribution over Germany, the merit order of capacity bids is altered to compensate for yield losses at sites with lower resource quality. The correction follows a non-linear heuristic based on the deviation from a reference wind generator. A second example of a heuristic allocation approach can be found in Sweden, where generation network tariffs depend on latitude. The differentiation of network tariffs incentivizes generation investment at lower resource quality sites close to demand. A third example is the German innovation tender ("Innovationsausschreibung"), which requires renewable projects to include storage to qualify for subsidies.

On the other hand, we test *explicit* approaches which allow storage investment at a limited number of candidate nodes identified as suitable in the optimal

[10] We model a perfectly efficient redispatch that includes all generation units in all modeled countries. Thus, the resulting total supply costs, i.e., dispatch plus redispatch costs, would be equal if capacity allocations in the nodal and uniform setting were the same. However, the allocation of new capacity is sub-optimal in the uniform case, resulting in higher total supply costs than in the nodal setup.

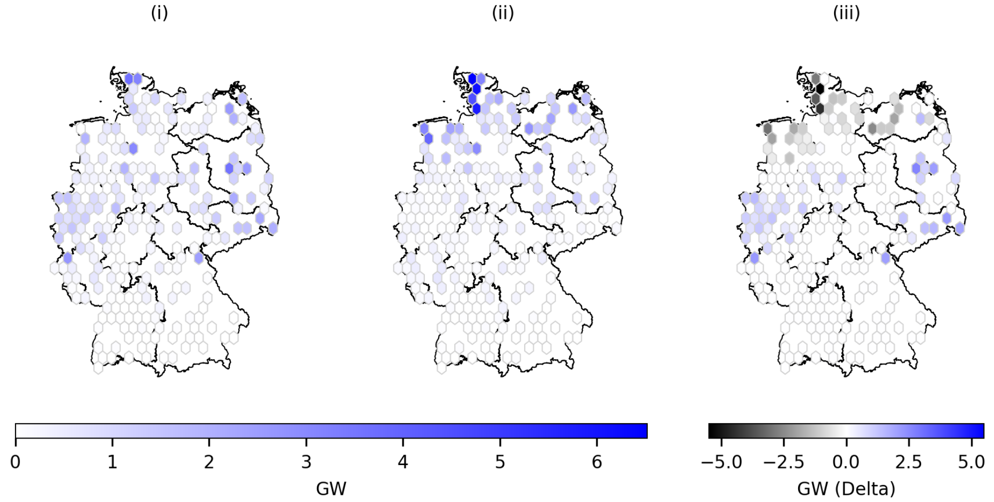
case. The capacity is then optimized across the candidate nodes. In practice, explicit allocation could be implemented through capacity auctions conducted by the grid regulator at preselected grid nodes. However, this approach requires detailed information on both current and uncertain, scenario-dependent future load flows — data the grid regulator does not possess. Since this challenge corresponds closely to the grid expansion planning, battery auction site selection could be incorporated into the grid development process. A similar policy is already implemented within the capacity auctions for wind generation, where a certain percentage of capacity is reserved for bids from the so-called south zone, a predefined area below the structural grid bottleneck. A different kind of location-specific capacity mechanism is used to procure the so-called grid reserve. The German grid regulator monitors the capacity demand for redispatchable power plants in the south of Germany. If available capacity is lower than capacity demand, grid operators can procure specific mothballed power plants or power plants scheduled for phaseout for grid reserve.

To rank the different instruments and their efficiency gains, we derive the optimal allocation of batteries for the uniform setup and use it for comparison. To obtain the optimal allocation, we perform a first model run calculating the distribution of wind and solar capacity without considering transmission constraints. Subsequently, in a second model run, we optimize the battery allocation considering transmission constraints and the given distribution of wind and solar. While the optimal allocation represents the upper bound for the efficiency achieved with a storage allocation mechanism, determining a lower bound is somewhat more complicated. In the uniform setting, there is no clear decision rule for storage because resource quality does not vary. Different factors such as demand typology, innovation drive or existing infrastructure could potentially influence storage allocation in the real world without spatially differentiated investment incentives. It is, however, unclear whether and how such factors influence the allocation and we, therefore, cannot include them in our model. Instead of a lower bound, we randomly distribute the storage across Germany as a benchmark for the absence of coordination incentives. Assuming that annual demand per node reflects the number of distribution voltage grid nodes suitable for battery connections, we apply a demand-weighted allocation. The random distribution is sampled 100 times and averaged to reflect an expected value. Finally, the results are compared to a run without batteries to quantify the supply cost savings, i.e. efficiency gains achieved by batteries.

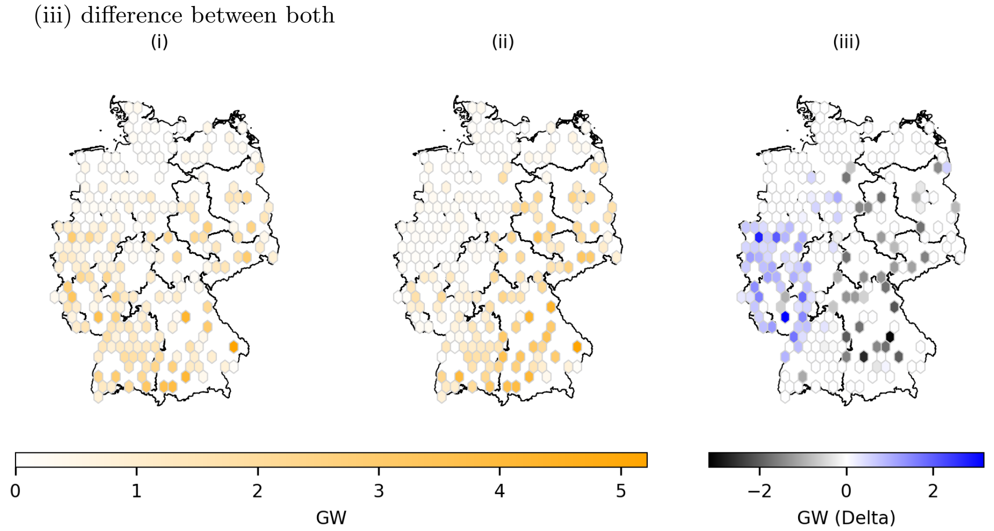
2.5. Numerical model results

2.5.1. Renewable allocation

Solar and wind power allocation is primarily driven by the consideration of transmission capacity. In the nodal setting, grid constraints are considered when siting new capacity. However, in the uniform case, investment decisions depend mainly on resource quality and, to a lesser extent, on feed-in patterns and resulting balancing effects. As a result, wind and solar capacity are distributed more broadly and closer to demand under the nodal setup. At the same time, it is concentrated at sites with high resource quality in the uniform setting. Figures 2.3a and 2.3b compare the spatial distribution of wind and solar capacity in both cases. Total capacity is exogenous for both settings and reflects Germany's 2030 capacity targets.



(a) Spatial distribution of wind capacity expansion in the (i) nodal and (ii) uniform setting and (iii) difference between both



(b) Spatial distribution of solar capacity expansion in the (i) nodal and (ii) uniform setting and (iii) difference between both

Figure 2.3.: Spatial distribution of wind and solar capacity expansion in the nodal and uniform setting (2030)

In the nodal setting, wind capacity peaks in the very north of the country, where resource quality is high. The rest of the capacity is widely distributed above the 50th parallel. Solar capacity is relatively evenly distributed below the 52nd parallel, despite higher resource quality in the south of Germany. All in all, significant shares of wind and solar capacities are allocated close to the demand centers in western Germany.

In the uniform setting, investment in wind power concentrates above the 53rd parallel. Solar capacity concentrates in Germany's south and east, with the majority of capacity installed below the 50th parallel. The lack of coordination of renewable feed-in and grid bottlenecks under the uniform setup leads to high curtailment. This especially affects wind power, which is separated from demand by a structural north-south grid bottleneck. In total, 109 TWh of renewable electricity are curtailed under the uniform setup in 2030, compared to only 30 TWh under the nodal setup.

2.5.2. Battery allocation

In both settings, batteries reduces supply cost, i.e., dispatch (and redispatch) costs. Note that the amount of battery capacity is imposed exogenously at 15 GW.[11] In the nodal setting, supply costs decrease by 1.1% compared to a case without batteries in the system. In the uniform setting, batteries can reduce supply costs by 1.5%. The drivers for the efficiency gains differ between the two settings. Under the nodal setup, wind, solar, and batteries are allocated in an integrated optimization and under the consideration of grid constraints. This allows wind and solar generation to be shifted to locations with higher full-load hours that were subject to grid constraints without batteries. Thus, renewable power generation increases, and higher-cost fossil generation is avoided compared to a case without batteries. In the uniform setting, supply cost reductions are split between cost savings in the initial market clearing and in redispatch. In the market clearing, batteries shift excess renewable energy to peak residual load periods, avoiding high-cost peak generation. The supply cost reductions are realized independent of the location and are equal in both battery allocation cases under the uniform setup. In redispatch, batteries create additional efficiency by avoiding high-cost generation behind grid bottlenecks. To achieve efficiency gains in redispatch, the allocation of batteries is relevant. This is illustrated by comparing a case of optimal battery allocation to a case of random battery allocation. On average, when allocated randomly, batteries can only decrease supply costs by 0.8% in comparison to a case without batteries. An optimal allocation sets the upper bound for supply cost reduction at 1.5%. Figure 2.4 compares the efficiency gains of placing 15 GW of battery capacity in the grid for the three cases.

[11] Thus, we do not investigate whether the savings in supply cost cover the capital cost of the batteries and hence do not infer conclusions about the economic efficiency of the chosen amount of batteries installed. We discuss some rough estimates at the end of section 2.5.4.

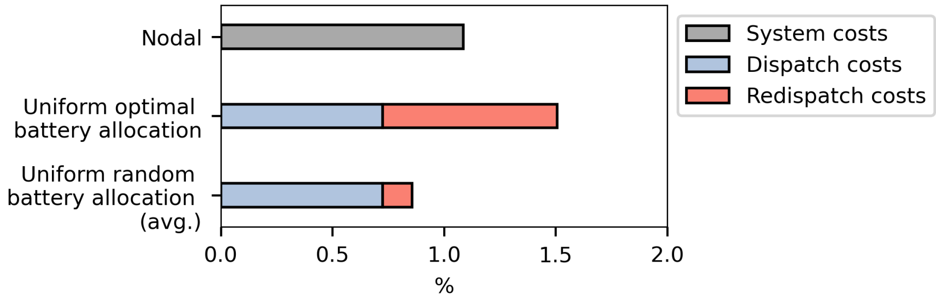
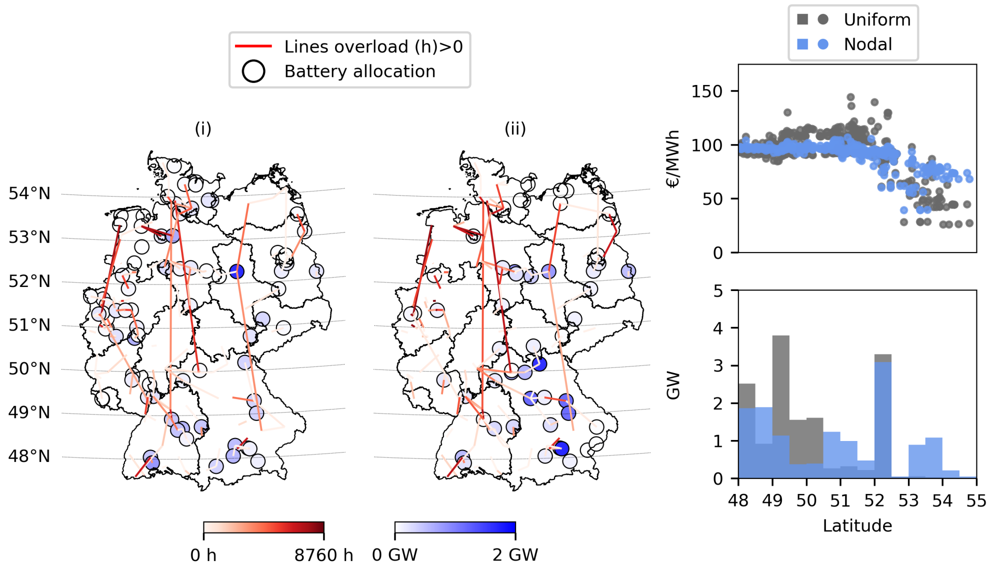


Figure 2.4.: Relative reduction of supply costs due to batteries in the nodal and uniform setting compared to the case without batteries (2030)

When comparing the two settings, we find that the total supply costs are 8.6% higher in the uniform than in the nodal setting for optimal battery allocation. This cost difference is attributed solely to the sub-optimal distribution of renewable generation capacity.

In both settings, nodal and uniform, the optimal battery allocation follows the allocation of wind and especially solar generation capacity. Thus, in the nodal case, batteries are allocated broadly across Germany, while in the uniform case, batteries concentrate in the south of Germany and especially below the 51st latitude. Moreover, under both settings, batteries are allocated close to congested transmission lines, i.e., lines that are frequently utilized at full capacity (depicted in red in Figure 2.5a).



(a) Optimal allocation of battery capacity and line utilization in the (i) nodal and (ii) uniform setting

(b) Nodal marginal supply costs and battery allocation by latitude

Figure 2.5.: Spatial distribution of 15 GW battery capacity and marginal supply costs (2030)

Grid congestion is illustrated in the upper graph of Figure 2.5b, which shows marginal supply costs at each node over latitudes. In the nodal setting, marginal supply costs equal the nodal prices. In the uniform case, they reflect the supply costs in redispatch. Prices differ between nodes if transmission constraints are binding, i.e., if a bottleneck exists. This is especially the case between the 52nd and 53rd parallel, where price differences of up to 44 EUR/MWh in the nodal case and 70 EUR/MWh in the uniform case occur. The price difference in the uniform setting is higher because the grid bottleneck is more prevalent here. This can be attributed to the sub-optimal renewable allocation in this case. In both settings, placing most of the battery capacity below the grid bottleneck is optimal. It follows the distribution of solar generation capacity. Thus, it is distributed more uniformly across the west and east in the nodal setting, while it is concentrated in the southeast (the federal state of Bavaria) in the uniform setting. Close to solar generation, batteries can flatten the daily solar generation profile, mitigate local grid congestion, and thus reduce local residual demand peaks. Doing so, batteries help to avoid the high-cost (re-)dispatch of conventional power plants in this area.

Furthermore, in both settings, a significant battery capacity of about 3 GW is allocated right above the structural north-south transmission bottleneck. Under the nodal setup, this capacity is shifted closer to western demand centers, where substantial wind and solar generation capacity is allocated. Through temporal shifting, these batteries increase the utilization of connections to the north and the usage of local wind and solar generation. In the uniform setting, the battery capacity allocated at the structural grid bottleneck is concentrated in the middle and the east of Germany, making use of solar capacity allocated there while at the same time increasing utilization of the easternmost HVDC connection.

The north of Germany, i.e., above the 53rd parallel, attracts a battery capacity of 1.4 GW under the nodal setup. The allocation of this capacity is the result of the simultaneous optimization of battery and renewable capacity allocation. Batteries allocated in the far north increase the north-south transmission utilization at locations where HVDC lines are connected. Thus, they enable wind generation to increase its full load hours by moving further northwards. This rationale does not hold under the uniform setup, where the optimization of renewables and batteries is decoupled. Additionally, the structural north-south bottleneck is too prevalent to achieve a similar transmission. As a result, there are no batteries allocated in the far north.

The numerical model results confirm for the case study of the 2030 scenario of Germany what the two-node model revealed: Storage can reduce supply costs in transmission constraint power systems with high volatility, but allocation matters to unlock the efficiency gains. For the case of batteries, we show that efficiency gains can be made, especially in conjunction with solar generation, as batteries flatten the daily generation pattern. By locating them near solar generation and grid congestion, the batteries avoid high residual demand peaks, i.e., costly generation during dispatch and redispatch.

2.5.3. Allocation rules for a spatial coordination of batteries

The uniform pricing setting sets no spatial coordination incentives for batteries; thus, achieving optimal allocation is unlikely. Therefore, we investigate the supply costs of potential allocation rules that could be realized by regulatory mechanisms that impose additional price signals under uniform pricing. We test for two types of capacity distribution mechanisms: *heuristic* allocation rules that allocate battery capacities over all nodes according to a predefined distribution and *explicit* mechanisms that allow battery allocation only at specific candidate nodes.

Heuristic allocation rules

As shown in the two-node model and the numerical example, optimal storage allocation is driven by the volatility induced by renewable feed-in, demand, and transmission grid constraints. Therefore, the first two heuristics distribute battery capacity proportionally to solar generation capacity and demand, respectively. Even though wind generation allocation is not a driver for optimal battery allocation in the uniform setting, we test whether batteries could exploit the volatility of wind generation and decrease supply costs when distributed according to wind generation capacity in a third heuristic. Heuristic four reflects the allocation of both wind and solar, thus taking a combined approach to renewable volatility. Capturing the dynamic influence of transmission grid constraints in a heuristic approach is more difficult. We investigate whether heuristic five can address grid congestion, which distributes storage capacity proportionally to phased-out power plants. Phased-out plants were historically allocated close to demand and therefore may address the north-south bottleneck.

To discuss the suitability of these heuristics, we assess them against the case without batteries given the distribution of wind and solar in the uniform setting discussed in the previous section. The relative savings in total supply costs resulting from the heuristics compared to the case with no batteries lies between 1.52 and 0.46% (see table 2.3).

Table 2.3.: Summary of relative cost differences and battery capacity factors for *heuristic* battery allocations (2030)

	opt. benchmark	random benchmark	solar	wind & solar	demand	phased-out power plants	wind
Supply cost delta [%]	-1.52	-0.87	-1.25	-1.15	-0.91	-0.63	-0.46
Redispatch cost delta [%]	-4.47	-0.80	-2.97	-2.38	-1.06	0.54	1.49
Battery capacity factor	0.15	0.15	0.16	0.15	0.16	0.13	0.08

As market efficiency gains are independent of the allocation, the differences in supply costs between the benchmark and the heuristic allocations correspond to the difference in redispatch costs, which are determined by the total redispatch volume and the power plants used in redispatch. The total redispatch volumes are similar in the benchmark case and for all heuristics. Redispatch is mainly caused by high wind power curtailment in the north of Germany. Situations of high wind feed-in and north-south transmission bottlenecks continue for long periods, and therefore the ability of batteries to reduce curtailment volumes is limited.

Hence, redispatch costs differ mainly due to the different types of power plants used for redispatch. Redispatch costs are lowest if batteries frequently shift low-cost electricity in time to avoid costly fossil-fired generation. In our scenario results, this is especially the case in the south and east of Germany, where high solar generation leads to high volatility in local marginal generation costs. Batteries can utilize this volatility by charging when solar power generation is high. They then use this energy to displace lignite power plants and gas turbines, which replace south German nuclear capacities, in redispatch. Conclusively, a heuristic, which distributes capacity according to solar generation capacity, is the most efficient, followed by a heuristic, which considers both wind and solar.

The demand-based heuristic is the third most efficient approach and naturally very close to the demand-weighted random distribution. Here, more battery capacity is located in the west of Germany, while solar power generation is concentrated in the east and south. Since marginal generation costs are higher in the west, battery charging is more expensive and replacement of fossil power plants in redispatch is less frequent. A similar effect occurs if the batteries are allocated accordingly to phased-out power plants since they are located near demand centers, too.

In contrast, if batteries are deployed close to wind generation, their contribution in redispatch is more limited. Even though batteries prevent more wind curtailment than in the other heuristics, they can only participate in redispatch above the structural grid bottleneck. There, marginal generation costs in redispatch are low, and so is volatility, making this allocation the least efficient. In fact, redispatch costs are even higher than in a case without batteries. This is because batteries increase the share of wind generation in the initial market outcome, which then has to be curtailed in redispatch due to grid constraints. However, market gains outweigh redispatch losses, resulting in lower total supply costs than without batteries. Moreover, the allocations according to wind or phased-out power plants are even less efficient than a random allocation of batteries. The random allocation leads to a broad distribution of batteries across Germany, meaning that at least some batteries are close to solar generation and demand.

The heuristics' supply cost differences are also reflected in battery utilization. In the wind-based heuristic, the battery capacity factor is less than half of the capacity factor of the solar-based heuristic, where a capacity factor of 0.16 is achieved. This corresponds to 345 battery cycles per year or an average of almost one charge cycle per day, i.e., a steady reduction of residual loads. The reason is the assumed capacity-to-volume ratio of 4h, which makes batteries better suited to buffer daily solar generation than wind generation profiles with their coarser volatility.

Explicit allocation rules

Secondly, we investigate *explicit* approaches that allow for an optimal battery allocation at predefined candidate nodes. We test the following variations: Starting from the 40 nodes with the highest battery capacity in the case with optimal battery allocation, we iteratively reduce the number of candidate nodes to 1. The resulting supply costs of these explicit allocation rules are between 1.52 and 0.68% lower than the benchmark without batteries. The higher the number of candidate nodes, the lower the supply costs. At 40 or more candidate nodes, supply costs are almost the same as in the optimal benchmark case. Even reducing the allocation to just two nodes leads to a cost decrease of 1.15%, which is close to the heuristic allocation according to solar and wind capacity. If the number of candidate nodes is reduced to one, the supply cost delta more than doubles compared to the case with two nodes. With one endogenously chosen candidate node, all capacity is placed at a node in southern Germany. In this case, the battery cannot have its full effect because the installed battery capacity is higher than the sum of renewable and transmission capacity at that node. Consequently, the resulting capacity factor is much lower, and the total supply cost is higher than in the case of random distribution. Nevertheless, it is noteworthy that the single-node allocation is still more efficient than an allocation by wind capacity or phased-out power plants.

The *explicit* approaches that distribute battery capacity to five or more nodes outperform all *heuristic* approaches. When comparing the results, however, it has to be noted that the installed capacity per node is optimized endogenously in the *explicit* cases. In contrast, capacity distribution is determined exogenously in the *heuristic* cases.

Table 2.4 compares resulting capacity factors and supply costs relative to the hypothetical benchmark for each of the *explicit* options.

Table 2.4.: Summary of relative cost differences and battery capacity factors for *explicit* battery allocations (2030)

	opt. benchmark	random benchmark	40	20	10	5	3	2	1
Supply cost delta [%]	-1.52	-0.87	-1.52	-1.49	-1.42	-1.36	-1.23	-1.15	-0.68
Redispatch cost delta [%]	-4.47	-0.80	-4.47	-4.36	-3.93	-3.57	-2.85	-2.43	0.28
Battery capacity factor	0.15	0.15	0.15	0.15	0.15	0.15	0.14	0.13	0.10

2.5.4. Summary

We quantify the efficiency gains of placing 15 GW of batteries in the German transmission grid. The supply costs in the uniform setting and a random battery allocation are 9.3% higher than in the theoretical first-best benchmark with nodal prices. An optimal allocation of batteries can reduce this efficiency gap by 0.7 percentage points to 8.6%. This remaining cost difference is attributed solely to the sub-optimal distribution of renewable generation capacities in the uniform setting. Comparing different allocation rules in the uniform setting to a case without batteries shows that batteries reduce supply costs for all considered allocations. The efficiency gains are composed of supply costs reduction in the electricity market, which are independent of battery allocation, and in redispatch, which depend on battery location. A hypothetical, optimal allocation for a given distribution of renewable capacity is used as an upper benchmark. Furthermore, a random distribution of batteries is used as a benchmark for missing local investment incentives.

The analysis shows for our scenario that *explicit* approaches with endogenous battery investment allowed at a limited number of pre-determined nodes can approximate the optimal distribution well, and already from five nodes, it outperforms all *heuristic* approaches with a fixed distribution. Among the fixed *heuristic* approaches, an allocation that mimics the distribution of solar generation capacity performs best. Solar generation is a crucial driver for optimal allocation since batteries can exploit the daily solar generation pattern to reduce gas-fired redispatch. Other *heuristic* approaches prove to be less suitable. An allocation proportional to phased-out power plants or wind generation capacity is less efficient than a random distribution. The wind-based heuristic leads to even higher redispatch costs than the case without any batteries.

Figure 2.6 shows the relative decrease in supply costs compared to the uniform setting without batteries for the allocation rules ordered by efficiency. It highlights the efficiency gains that can be made by introducing and coordinating batteries. The most efficient allocation rule is the *explicit* allocation to 40 nodes, leading to 1.52% lower supply costs than the benchmark without batteries. Least efficient is the *heuristic* allocation by wind capacity (-0.46% supply costs).

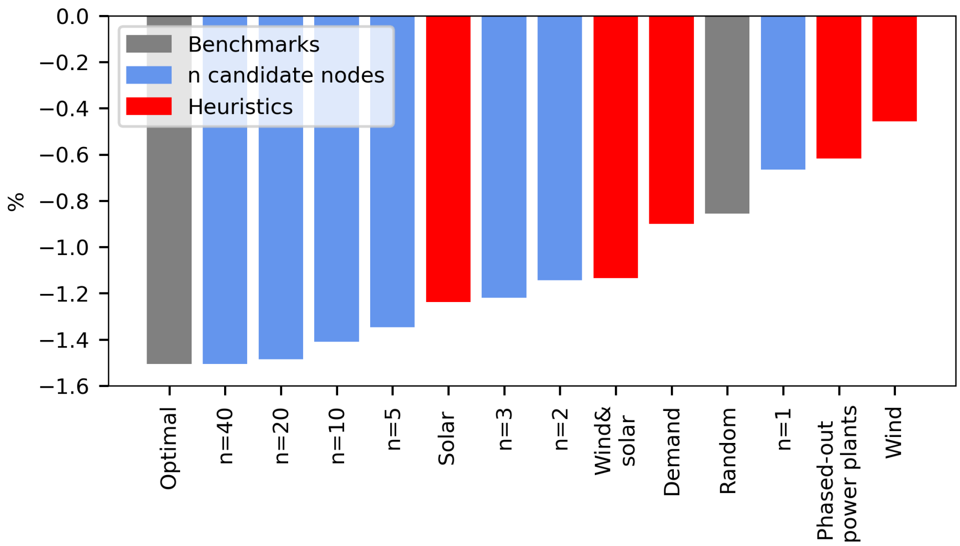


Figure 2.6.: Supply cost differences between different battery allocation scenarios and the uniform setting without batteries (2030)

The relevance of appropriate coordination can be further illustrated by relating the supply cost savings achieved by batteries to the capital cost incurred. The supply cost saving of each battery allocation is the difference in total supply costs compared to the uniform setting without any batteries. To calculate the capital costs of batteries, we assume investment costs of 600 EUR/kW, a lifetime of 16 years, and an interest rate of 8% (c.f. EWI, 2021). The ratio of savings to annualized capital cost depends strongly on battery allocation. Batteries can yield 1.08 EUR in savings per euro spent if allocated optimally in the uniform setting. A random allocation reduces the savings by 47 ct per euro spent. With an explicit allocation at five or more candidate nodes, the battery-induced savings come close to the savings under an optimal allocation (0.96 - 1.08 EUR saved per euro spent, depending on the number of nodes). In the best heuristic allocation (solar), the ratio of savings to expenditures is 19 ct lower than with an optimal allocation. In the worst case (wind) examined, the savings drop to just 33 ct per euro spent. Under the assumed capital costs, 15 GW of battery capacity is in the money if allocated optimally. With the help of the allocation rules, savings are higher than the annualized capital costs for explicit approaches at 10 or more nodes. With all other rules, savings are below expenditures. However, batteries can generate additional value not considered in the present analysis through system services, e.g., balancing power provision or avoiding grid expansion in the long run and thus savings can be higher.[12] Further, these results highly depend on the (assumed) capital costs.

2.6. Discussion

2.6.1. Generalization

Although the numerical model results are specific to the chosen setting, they can be generalized for several aspects. First, the finding of the two-node model that optimal storage allocation is driven mainly by volatility is valid and applicable for all time horizons and countries. This has been confirmed in various numerical studies, e.g. Cebulla et al. (2017), Babrowski et al. (2016) and Schlachtberger et al. (2017). In our case study of Germany's power system in expected 2030 conditions, solar power is the dominating renewable capacity driving volatility and, thus, battery allocation. Divergent renewable energy shares may lead to different optimal battery allocations, e.g., previous analyses assuming higher shares of wind power conclude that higher shares of battery capacity should be allocated near wind energy (see Babrowski et al. (2016)).

Secondly, the numerical analysis at hand focuses on batteries, i.e., a storage technology with a relatively small storage volume compared to installed charging capacity, which complements the daily fluctuations of solar power generation. Therefore, we perform a sensitivity analysis regarding the storage type and show that the optimal allocation depends on the specific technology. In particular, storage with a larger power-volume ratio is favorable at locations with high shares of wind power (see A.4.2, as well as Cebulla et al. (2017) and Schlachtberger et al. (2017)).

Thirdly and contrary to other analyses that optimize allocation of storage without considering Germany's uniform pricing market design, we show that storage can generate value in both the initial market clearing and in redispatch. The latter depends on the allocation of batteries and can only be exploited if the market design allows for the participation of storage in redispatch. If this is not the case, a substantial part of the potential benefits of storage technologies - in our numerical analysis, about 50% - cannot materialize.

[12] However, if the use of batteries for other applications also affects their wholesale market operation pattern, e.g. by providing balancing power, the impact on supply cost savings needs to be analyzed from an integrated perspective.

Fourthly, the findings for the transmission level can be used to get insights for the distribution grid. Distribution grid operators could use the batteries' flexibility to lower curtailment volumes and required grid expansion if the batteries' allocation matches flexibility demands and technical and regulatory properties allow. However, on the distribution grid level, storage is usually used to increase the self-consumption of solar generation, e.g., home-storage systems. Therefore, these systems are neither dispatched by market signals nor used in redispatch, making the findings of this analysis not readily transferable.

2.6.2. Limitations

Several limitations should be noted when considering the results and analysis presented. First, the numeric modeling results are based on several strong assumptions, e.g., perfect foresight, no transaction costs, perfect markets, and the exogenous distribution of inelastic exogenous demand. The mathematical duality between a central planer and a profit-maximization of symmetric firms holds only if these assumptions are all met. In practice, this is rather not to be expected. In particular, the first-best nodal benchmark is a rather theoretical benchmark as in reality frictional losses can distort optimality, e.g., reduced liquidity, lack of transparency, market power issues, and increased transaction costs (c.f. Antonopoulos et al., 2020).

Furthermore, modeling the market setup of uniform pricing, as it is currently in place in Germany, comes along with some simplifying assumptions. We abstract from additional policy instruments for the expansion of wind and solar power. In particular, the reference yield model should affect wind power expansion compared to our modeled distribution. The cost-based redispatch mechanisms applied in practice are less efficient than those modeled in our numerical analyses. In our model, power plants outside Germany and all technologies including storage can be used for redispatch without any restrictions, which is not necessarily the case in practice. In particular, redispatch of hydro-pumped storage in the Alps can be fully exploited in the model which might cannibalize the value of batteries in Southern Germany. Additionally, further efficiency gains of storage deployment are possible, which were not part of the numerical analyses, e.g., avoided grid expansion or increased security of supply.

In addition to these model properties, the results have to be interpreted in light of the specific scenario chosen for the analysis. To demonstrate the robustness of our results, we perform a sensitivity analysis regarding the total installed battery capacity in A.4.2. Additionally, the scenario-specific renewable energy allocation largely determines the magnitude of the identified efficiency gap between the first best nodal and the uniform setting. Besides resource quality, further aspects, such as land availability and residents' opposition, play into renewable investors' decision process. Hence, the resulting renewable energy distribution for 2030 is likely to be less concentrated in reality, which also impacts the optimal storage allocation and system efficiency.

2.7. Conclusion and policy implications

This paper investigates the allocation of battery storage in spatially unbalanced power systems in the transition to climate neutrality, i.e., with rapidly increasing shares of wind and solar power generation. Specifically, we seek to answer three questions: Firstly, where in the transmission grid should batteries be allocated, secondly, how important is storage allocation for the system's efficiency, and thirdly how could policy instruments be designed to approximate an optimal allocation?

To investigate the drivers of optimal storage allocation, we develop a theoretical two-node, two-time-step model that simplifies the dynamics of spatially unbalanced power systems. We show that an allocation close to volatile renewables or close to demand can be optimal. We find that optimal allocation depends on the volatility and location of demand and generation relative to grid bottlenecks.

These results are verified and expanded in a numerical case study using the example of a spatially unbalanced power system in Germany. The largest efficiency difference occurs between the nodal and uniform setting. Supply costs are at least 8.6% higher in the uniform setting than under the nodal setting. This is primarily because in the nodal setting wind and solar generators are allocated optimally and shows that the leverage of a simultaneous allocation and coordination of wind and solar expansion exceeds the leverage of allocating batteries. However, the results in the nodal setting rely on several assumptions that tend not to hold in practice, and switching from uniform to nodal pricing may not be politically feasible.

Our analysis reveals that under uniform pricing an optimal allocation of battery capacities can increase efficiency by 0.7 percentage points compared to a random battery allocation, which results in an efficiency gap of 9.3% compared the nodal setting. Although this seems small in comparison to the efficiency gap caused by inefficient allocation of renewables (8.6%), in relation to the cost of battery investments, this corresponds to almost a doubling of the supply cost savings per euro spent. It is, therefore, worth discussing how coordination can be achieved and local incentives can be set even in a system with uniform pricing. In Germany, this question is currently being asked as part of the government initiative *Climate Neutral Electricity System Platform* - a dialogue platform that aims to prepare for an upcoming electricity market reform.

Our model results show that several allocation rules are suitable to approximate an optimal allocation of batteries in the uniform setting. For example, a heuristic approach that allocates batteries close to solar capacity or explicit approaches that rely on grid analyses to determine a limited number of locations for a capacity auction can reduce supply costs in the uniform setting. In addition, implementing such an allocation rule would ensure that inefficient distributions, like an allocation close to installed wind power capacity, are not realized.

Policymakers designing regulatory instruments based on these findings should weigh the reduction in supply costs resulting from improved allocation against the implementation costs. In the case of the heuristic approaches, the difficulty lies in identifying a mechanism that yields the desired distribution of batteries. Costs could also be incurred if the chosen mechanism leads to a high number of transactions, e.g., if batteries were subsidized via feed-in tariffs. For the explicit approaches that allow the installation of batteries at limited locations in the grid, the allocation could be managed via a limited number of auctions. Here, transaction costs arise from the information asymmetries of the regulator in determining optimal locations and capacities. Further, our results benefit from the assumption of perfect foresight. In practice, it may be more complicated to determine optimal candidate notes ex-ante, in particular, if only a few nodes are chosen and in a dynamic setting the optimality of nodes may change over time. Choosing a heuristic approach directly connected to the distribution of solar power may be more robust to the deviations from a modeled scenario.

Policies that coordinate wind, solar, and storage capacity in an integrated way could come even closer to the first-best benchmark. One potential approach is splitting Germany's uniform price zone, as currently discussed by the European grid regulator. A price zone split could create broad allocation incentives (e.g., Zone A vs. Zone B) and enhance long-term efficiency. However, the proposed splits for Germany mainly address the structural North-South bottleneck and overlook periodic, more localized PV-induced congestion (cf. Zinke, 2023). Thus, it remains uncertain whether a simple two-zone split would provide efficient allocation incentives and further analysis is therefore needed.

We conclude that it is possible to design a policy instrument based on allocation rules that are suitable to approximate an optimal storage allocation under uniform pricing. Any potential policy should either be simple and low-cost to implement or be part of a comprehensive mechanism that coordinates all types of generation and flexibility with the grid.

3. Three Zones Fix All? Analyzing Static Welfare Impacts of Splitting the German Bidding Zone under Friction

3.1. Introduction

Germany's electricity transmission grid is consistently congested between the North, where the majority of wind power plants are located, and the South, where demand is concentrated. Consequently, redispatch[13] costs have risen from 1 bn EUR in 2019 to 4 bn EUR in 2022 (Bundesnetzagentur and Bundeskartellamt, 2023). Additionally, grid congestion in Germany results in unintended loop flows[14] through neighboring countries, thereby diminishing cross-border trading capacities (ACER, 2024). These issues have positioned Germany at the center of attention in the most recent bidding zone review (BZR), a periodic formal evaluation of bidding zone configurations in the European electricity market conducted by the European Union Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E). The BZR, which was conducted between 2019 and 2025, assessed several potential reconfiguration options for the German[15] bidding zone for the target year 2025, but did not arrive at a definite recommendation - mainly due to the fact that main assumptions were outdated by the time the review was published (ENTSO-E, 2025). Still, the six year long process ignited an extensive debate on splitting the German bidding zone among academics and affected market participants.

A key argument in favor of splitting the German bidding zone is that a split would internalize congestion into market prices, thereby enabling market participants to react to congestion. This could reduce redispatch costs, which are ultimately borne by consumers through grid fees (Zachmann, 2024). However, concerns have been raised that smaller zones might diminish market liquidity and increase the risks of market power (Brouhard et al., 2020). Additionally, opposition is emerging from stakeholders in the South of Germany, who are likely to face negative distributional effects, with higher electricity prices following the

[13]Redispatch refers to the practice of reducing the output of generators located before a grid bottleneck and increasing generation behind the bottleneck. Generators involved in redispatch are compensated for their costs and foregone profits.

[14]Loop flows are unintended power flows that occur when electricity, due to physical grid constraints, takes indirect or parallel routes through neighboring transmission networks.

[15]Germany and Luxembourg form a bidding zone together, which is referred to as the "German bidding zone" for simplicity.

split (Baden-Württemberg Association of Chambers of Commerce and Industry e.V. et al., 2024).

Looking at static welfare implications, although it might imply distributional effects, a bidding zone split should be welfare neutral - in theory and if there are no frictions. In reality, however, several types of friction may lead to changes in static welfare when splitting the German bidding zone:

1. **Liquidity and market concentration:** Smaller zones may lead to lower liquidity, which in turn may reduce market efficiency by limiting price discovery and increasing transaction costs in the face of higher volatility and increased bid-ask spreads. Additionally, smaller zones may have higher market concentration, making them more vulnerable to market power. At the same time, reduced loop flows on interconnectors may enhance trade between zones, potentially improving liquidity or at least the option to (proxy-)hedge on markets in neighboring zones (Compass Lexecon, 2024).
2. **Inefficient redispatch:** A fully efficient redispatch without frictions leads to the same dispatch regardless of the zonal configuration and zonal market outcome. In fact, the final outcome after redispatch is equivalent to the first best result under nodal pricing where each market constitutes a market and all physical grid constraints are reflected in prices. In reality, ramping constraints and restricted participation of certain power plant types, storage, and demand prohibit redispatch from reaching the efficient market outcome, causing frictions (c.f. Bjørndal et al., 2003).
3. **Approximative allocation of transmission capacity:** Transmission capacity between most bidding zones in Europe is allocated via flow-based market coupling (FBMC), an algorithm designed to allocate transmission capacity between zones in a welfare-maximizing manner during market clearing. FMBC is based on an ex ante approximation of physical grid properties. In light of potential approximation errors, transmission capacity is reduced by fixed security margins to avoid line overloading (c.f. Felten et al., 2021). Increasing the number of bidding zones adds more transmission constraints subject to approximation and security margins, thus limiting trade and potentially market efficiency.

Setting aside potential liquidity and market power effects[16], it is the interplay of redispatch and transmission capacity allocation frictions that determines the static welfare impact of a bidding zone split. It is clear that there exists a trade-off between reducing redispatch volumes by internalizing congestion versus imposing trade restrictions by adding more approximation-based constraints. The trade-off hinges on redispatch efficiency: If redispatch is inefficient, reducing redispatch volumes may lead to higher cost savings, thus increasing welfare. If redispatch is efficient, the effect dwindles, putting more emphasis on the market

[16] Liquidity and market power effects of bidding zone configuration are discussed in detail in Compass Lexecon (2024) as part of the BZR process.

losses from additional trade restrictions - though it has to be kept in mind that a fully efficient redispatch can in theory mitigate welfare losses in the market regardless of the zonal configuration, leaving only distributional effects.

This paper analyzes static market and welfare effects of a bidding zone split in Germany in 2030. Adding to the large body of research existing on the subject, it makes the following contributions: It employs a state-of-the-art grid and market model to represent frictions in redispatch and transmission capacity allocation under FBMC. Additionally, while relevant existing research has primarily focused on two-zone configurations, this paper is the first to investigate a three-zone setup, providing insights into the implications of more granular market structures. The analysis includes prices, rents (consumer, producer, and congestion), redispatch costs, and subsidy expenditures for supporting RES as according to German policy, to give a full picture of welfare and distributional effects. Sensitivity analyses explore the influence of scenario specification and frictions in redispatch.

The following main findings could be derived: From a German perspective, for the investigated 2030 scenario, and under the considered frictions - approximative transmission capacity allocation under FBMC and redispatch inefficiencies -, splitting the German bidding zone leads to modest static welfare changes. The direction of welfare changes depends on the bidding zone configuration: While static welfare increases by 4.4 % in the case of three zones, it decreases by 1.6 % in the case of two zones. Thus, welfare losses due to more transmission constraints in the market cannot be compensated by redispatch cost savings in the investigated two-zone setup. Three zones reflect the physical properties of the grid more closely, resulting in additional cost savings for redispatch and an increase in overall static welfare. Still, both investigated bidding zone split scenarios lead to significant distributional effects with the majority of consumers being exposed to higher prices and increased subsidy expenditure for renewables - especially in the two-zone setup where prices diverge significantly.

Three sensitivity analyses show that the impact of a bidding zone split depends on the scenario choice and the representation of frictions. Lower congestion in the case of delayed wind capacity expansion diminishes positive effects of a bidding zone split, while higher congestion in the case of delayed grid expansion leads to significant welfare gains to be made by splitting the German bidding zone. Reducing frictions in redispatch via a full participation of batteries renders bidding zone splitting less efficient.

All in all, the analysis shows that splitting the German bidding zone does not guarantee static welfare gains and welfare outcomes depend on the exact configuration of the zones, the scenario and frictions in redispatch and transmission capacity allocation. Policymakers must be aware of these effects when deciding on a bidding zone split. Furthermore, splitting the German bidding zone implies significant distributional effects, e.g. by increasing the costs of the RES subsidy scheme. In any case, welfare effects must be weighed against implementation costs, potential effects of lower liquidity in smaller zones, and dynamic welfare effects in the face of changing power systems.

The remainder of this paper is structured as follows: Section 3.2 reviews the existing literature and highlights this study's contribution. Section 3.3 describes the model, evaluation methods, and the scenario. Section 4.3 presents the results, which are discussed in Section 3.5. Finally, Section 3.6 concludes on the findings.

3.2. Literature Review and Contribution

Numerous studies assess the market and welfare implications of splitting the German bidding zone (c.f. Table 3.1). Most studies consider a North-South split into two zones, though exact delineations differ. Most researchers focus on electricity prices, redispatch costs and welfare in a static settings, though some researchers incorporate capacity expansion and quantify dynamic efficiency. Most researchers employ numerical optimization models simulating market dispatch and redispatch. However, scenario assumptions such as demand, fuel prices and renewable energy expansion vary and models differ in the consideration of frictions in redispatch and transmission capacity allocation. Redispatch modelling methods vary from fully efficient redispatch, and different representations of frictions, e.g. excluding certain generator types or imposing cost penalties on redispatch. Regarding transmission capacity allocation frictions, it has to be noted that many papers employ simplified models with only a few representative grid nodes and ex-ante determination of transmission capacity between zones, which cannot represent frictions due to inaccuracies and security margins in FBMC procedures. Table 3.1 summarizes the literature and lists analyzed parameters, considered frictions, and scenario years.

Table 3.1.: Literature on splitting the German bidding zone

	Analysis					**Frictions**		
Citation	Prices	Redispatch	Static welfare	Subsidies	Dynamic welfare	Redispatch inefficiency	FBMC	Scenario years
Burstedde (2012)	✓	✓	✓			✓		2015, 2020
Breuer and Moser (2014)	✓	✓	✓			✓		2016, 2018
Trepper et al. (2015)	✓	✓	✓			✓		2012, 2020
Egerer et al. (2016)	✓	✓	✓					2012, 2015
Plancke et al. (2016)	✓							2020
Van den Bergh et al. (2016)		✓					✓	2013
Ambrosius et al. (2018)	✓	✓	✓		✓	✓		2035
Grimm et al. (2021)	✓	✓	✓	✓	✓	✓		2035
Fraunholz et al. (2021)	✓	✓	✓		✓	✓		2025, 2035
Felling et al. (2023)	✓	✓	✓				✓	2020
Zinke (2023)	✓	✓				✓	✓	2021-2035
Brouhard et al. (2023)	✓	✓	✓					2030, 2040
Dobos et al. (2024)	✓						✓	2025
Knörr et al. (2024)	✓	✓					✓	2025
Frontier Economics (2024)	✓							2025, 2030
Tiedemann et al. (2024)				✓			✓	2030

Studies that assess the impact of a bidding zone split for the years 2025 to 2035 are most relevant to this work. These studies come to different conclusions regarding market and welfare effects. For example, price levels for the single German bidding zone in 2030 range from 56 EUR/MWh (Tiedemann et al.,

2024) to 80 EUR/MWh (Fraunholz et al., 2021). North-South price differences are found to lie between 5 and 15 EUR/MWh across scenarios and years from 2025 to 2035, with a decreasing tendency in later years when (planned) grid expansion reduces grid bottlenecks (c.f Frontier Economics, 2024, Knörr et al., 2024, who provide an overview of existing literature).

Redispatch costs generally decrease under zone splitting but vary widely, from savings of 117 million EUR (Fraunholz et al., 2021) to over 2 bn EUR in Zinke (2023) for 2025 and over 4 bn EUR in 2030.

It has to be noted that the consideration of frictions in redispatch varies significantly across studies. For example, Brouhard et al. (2023) assume a fully efficient redispatch solving all inefficiencies after the market clearing, which leads to the same supply costs regardless of the zonal configuration. In contrast, in Zinke (2023), the participation of demand and certain generator types in redispatch is restricted. Ambrosius et al. (2018), Fraunholz et al. (2021), and Grimm et al. (2021) impose penalties so that redispatch only changes market outcomes that actually violate physical transmission constraints instead of optimizing the whole dispatch.

In terms of distributional effects, i.e. changes in consumer, producer and congestion rents, results differ as well. Some report higher electricity costs and reduced consumer rents, such as 1–3 bn EUR in Fraunholz et al. (2021), while Grimm et al. (2021) find slight increases in consumer rents. It has to be noted that the zonal configuration considered in Grimm et al. (2021) splits Germany below North-Rhine-Westphalia, which is in the South zone in most other approaches. This allocates more demand in the low-price zone.

Producer surplus findings are mixed, with increases reported in Grimm et al. (2021) and Brouhard et al. (2023) and mixed results in Fraunholz et al. (2021).

As market prices influence generator revenues, splitting the German bidding zone may also affect subsidy expenditures. Only few studies address this. For example, Grimm et al. (2021) find slightly increased RES fees in case of a North-South bidding zone split, which they calculate as the difference between investment costs and market revenues, split equally across consumers.[17] Similarly, Tiedemann et al. (2024) find slightly increased subsidy expenditures for PV and wind onshore for a North-South split under exemplary market premiums and current installation costs. However, their analysis excludes historical installations still in the subsidy scheme and subsidy expenditures for them.

Lastly, congestion rents are generally found to increase under a bidding zone split.

Assessments of total static welfare for future scenarios, especially under friction, are scarce. In Brouhard et al. (2023), where redispatch is frictionless, the

[17]Until 2021, subsidy costs were recovered via a levy on electricity prices, the RES fee. Grimm et al. (2021) do not report absolute subsidy expenditure.

bidding zone split is welfare neutral - this also means that frictions in transmission capacity allocation do not matter for overall welfare.

Instead of static welfare, several studies project dynamic welfare for future scenarios, modelling endogenous capacity expansion for grid or power plants (Ambrosius et al., 2018, Fraunholz et al., 2021, Grimm et al., 2021). In these studies, there are different representations of frictions, although their effect is entangled with the dynamic development of the power sector. All three consider frictions in redispatch, with Ambrosius et al. (2018) excluding generators in other zones and Fraunholz et al. (2021) and Grimm et al. (2021) imposing redispatch penalties to minimize redispatch volumes. Regarding frictions in transmission capacity allocation, it has to be noted that all of the approaches considering dynamic efficiency have to rely on simplified load flow representation to keep models computationally tractable. This includes ex-ante determination of transmission capacity between zones, and, in the case of Ambrosius et al. (2018) and Grimm et al. (2021) reduced grid resolution with only 16 nodes in Germany. Thus, they are unable to address frictions arising in FBMC. This friction is analyzed explicitly only in Felling et al. (2023), who optimize bidding zone configurations across Europe (regardless of national borders) for a 2020 scenario and analyze static welfare. They find that static welfare increases with more zones, as redispatch (frictions are modelled via a penalty) is reduced further. However, the welfare increase is non-monotonic. They attribute this to the mathematical properties of the flow-based domain[18], the negative effect of additional load flow constraints and approximation errors inherent to FBMC. This result highlights that static welfare is determined by the interplay of the exact zonal configuration, and frictions in redispatch, and FMBC.

In summary, the literature lacks consensus on the effects of bidding zone splitting, with variations likely driven by scenario differences and the considerations of frictions - which are often not made explicit. Additionally, among recent studies, none provides a comprehensive static welfare analysis of a bidding zone split in a post 2020 scenario and none considers a three-zone setup. This paper addresses this gap by analyzing 2030 static market and welfare impacts of a German bidding zone split, including subsidy expenditure. To explicitly consider frictions, it uses a state-of-the-art model with inefficient redispatch and FBMC.

3.3. Methods

3.3.1. Grid and Market Model and Representation of Frictions

This study uses a detailed model of the central European electricity market, including frictions in redispatch and transmission capacity allocation via FMBC,

[18]For a detailed discussion the reader is referred to Felten et al. (2021)

to derive the effects of a bidding zone split in Germany on electricity prices, static welfare and distribution effects, and renewable energy subsidy expenditure.

The model was first developed in Schmidt and Zinke (2023) and further extended in Czock et al. (2023) and Zinke (2023). The model is an optimization-based framework that simulates electricity market clearing by minimizing the cost of electricity supply, considering demand, available power plant and transmission grid capacity, and storage constraints. It relies on the assumption of perfect markets and perfectly inelastic demand, which allows for duality between cost minimization (i.e., welfare optimization by a social planner) and market outcomes.

The FBMC implementation requires a multi-step modelling procedure. It is described in detail in Zinke (2023), but the following outlines the key features relevant to this study, which are also illustrated in Figure 3.1.

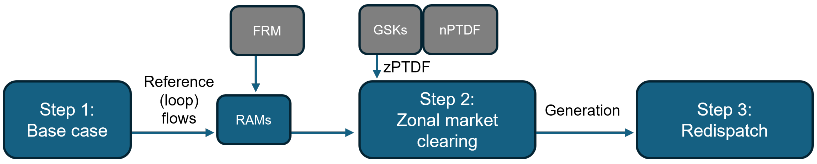


Figure 3.1.: Grid and market modelling procedure

Under FBMC, transmission capacity between zones is allocated during the market clearing stage in a welfare-maximizing manner. To achieve this, trade is subject to several constraints, reflecting the physical properties of specific lines, the critical network elements (CNEs).[19] First, trade between zones is restricted by the *remaining available margins* (RAMs), determined ahead of market clearing. The RAMs are based on line capacity but account for loop flows caused by intra-zonal transmission and typically include security margins (e.g., the *flow reliability margin* (FRM), which is deducted from line capacities). Additionally, market clearing includes constraints representing the sensitivity of power flows on each CNE regarding the net positions of the zones, considering that flows between two zones may impact flows between other zones (c.f. e.g. Van den Bergh et al., 2016).

To determine RAMs, the first modeling step is computing a *base case* that quantifies reference flows, i.e., loop flows caused by intra-zonal transmission. In this study, the base case is a model run without trade between zones. The second step is the *zonal run*, which models market clearing and trade between zones under the consideration of RAMs derived from line capacities, reference flows, and the FRM, which is set to 10 % in this study (c.f. Zinke, 2023). The sensitivity of flows on each CNE regarding changes in the net position of a zone (i.e., changes in flows on other lines) is modeled via zonal power transfer distribution factors (PTDFs). Zonal PTDFs (zPTDFs) are derived as the zonal sum of nodal PTDFs,

[19]For this study, only intra-zonal lines are considered as CNEs (see Zinke (2023) for a discussion of this assumption).

which can be computed from line reactances, weighted by generation shift keys (GSKs). GSKs represent assumptions on how net changes in the zonal saldo are distributed among nodes within a zone and are based on the proportion of a node's hourly generation in the total generation of a zone for this study. Both, the default reduction of line capacity by the FRM and potential approximation errors in the GSKs introduce frictions into the model, closely resembling real world FMBC procedures. The effect of the FRM is straightforward as it reduces RAMs and essentially trade between zones and therefore the efficiency of the market clearing. The effect of approximation errors in the GSKs is more complex, as they translate into inaccuracies in the load flow constraints (compared to the actual physical constraints). If RAMs are underestimated, trade is inaccurately restricted again. If RAMs are overestimated, redispatch volumes increase (c.f. Felten et al., 2021, who provide a detailed assessment of the impact of errors in the flow-based parameters).

The final modelling step, the *redispatch run*, simulates the adjustment of power plants to solve intra-zonal congestion after the market clearing. The redispatch run considers all physical transmission constraints, represented by a linear DC load flow based on a cycle-formulation of Kirchhoff's laws. The following frictions are applied to approximate frictions in real-world redispatch: Trade between zones remains fixed, as TSOs cannot access power plants outside their zones for redispatch.[20] Intermittent RES and batteries are only allowed to reduce supply during redispatch, while other generation technologies can be dispatched flexibly. In reality, batteries with a capacity > 100 kW can be accessed for both positive and negative redispatch but there is no mechanism that ensures that they are charged for positive redispatch ahead of time.

Market and Static Welfare Effects

The results from the zonal run can be used to analyze the static efficiency effect of a bidding zone split. First, wholesale electricity prices can be derived as the marginal cost of electricity generation. Second, changes in consumer rents between bidding zone configurations can be derived from the wholesale electricity prices. Consumer rents refer to the difference between consumers' willingness to pay and market prices. Changes in consumer rents, called ΔCR, equal the difference in wholesale electricity costs, i.e. wholesale electricity prices weighted with hourly demand. For the calculations of ΔCR, only inflexible demand is considered.[21] Similarly, zonal dispatch results allow the calculation of producer rents. Producer rent refers to the difference between generation costs and electricity market prices. Producer rent changes between bidding zone configurations are denoted as ΔPR.

[20] To represent a continuation of coordinated redispatch in Germany, trades between German zones may be adjusted in the redispatch run when a bidding zone split is considered.

[21] Electrolysis and storage, like batteries or pumped storage, generate additional electricity demand, but they are regarded as generators in the analysis of rents.

Finally, congestion rent (or congestion income) can be derived. Congestion rent is a revenue stream for TSOs arising from price differences between electricity trading zones with limited transmission capacity. When demand for imports exceeds transmission capacity, markets decouple, creating price differences. Electricity traded from a lower-cost to a higher-cost zone is sold at the higher price, but generators in the lower-cost zone receive only their local price. The price difference constitutes congestion rent, collected by TSOs. Under European legislation, TSOs are required to use congestion rent income to fund grid expansion or ensure system reliability. Thus, congestion rent is often considered as welfare-relevant on the consumer side because it should reduce grid fees if used to refinance TSO activities. The change in congestion rent between two bidding zone setups is called ΔCI.

Subsidy Expenditure

The zonal dispatch results also allow analyzing the impact of bidding zone splitting on subsidy expenditure. The *Law on the Expansion of Renewable Energies* (German: EEG) subsidy scheme supports renewable energy generation by paying fixed feed-in tariffs or market premiums to producers. Market premiums emerge from renewable capacity auctions, held several times per year, and electricity market prices. In these auctions, generators bid a per kWh asking price, the so-called *reference value*, and lowest bids are selected up to the predetermined capacity. Some renewable energy projects, such as pilot units or community energy initiatives ("Bürgerenergieanlagen"), do not participate in the auctions and have reference values fixed by regulators.[22] Generators sell their electricity on the markets and receive market premiums, calculated as the difference between their reference value and the average market value of their technology.

Subsidy expenditure, i.e. the cost of the subsidy scheme, thus varies with reference values and, more significantly, electricity prices. Part of the renewable capacity is subsidized using fixed feed-in tariffs instead.[23] The energy generated by producers under fixed feed-in tariffs is marketed by TSOs, so that subsidy expenditure equals the difference between market prices and fixed tariffs. These costs are recovered through the federal budget, effectively passed on to consumers via taxes.

For this study, subsidy expenditure is calculated as the difference between investment and fixed operation and maintenance (FOM) costs and revenue from electricity markets. Costs are annualized over 20 years, reflecting the duration of EEG subsidies.

Next to RES, there are plans to subsidize backup capacity (SPD et al., 2025). The design of the subsidy scheme is still under discussion. Therefore, subsidy expenditure for backup capacity is calculated as the difference between revenues from electricity markets and investment, FOM and variable costs.

Differences in subsidy expenditure between scenarios are denoted as ΔS_{RES} and ΔS_{BU} for RES and backup generators respectively. It is important to note that changes in subsidy expenditure represent transfers between consumers and producers, not changes in total supply costs or welfare.

[22] Additionally, the reference yield model ("Referenzertragsmodell") adjusts reference values for onshore wind based on location-specific productivity. It compares a turbine's projected energy yield over five years to a standardized reference yield, with less productive locations receiving higher subsidies to incentivize wind in southern Germany.

[23] For example, capacity built before 2014 under an earlier version of the EEG or units below 100 kW.

Redispatch Costs

Redispatch costs are calculated as the difference in supply costs between redispatch and zonal runs. Thus, capital depletion and opportunity costs which generators are reimbursed for in redispatch in reality, are neglected. Changes in redispatch costs between scenarios, denoted as ΔRD, are welfare-relevant on the consumers' side if they are passed on via grid fees.[24]

3.3.2. Bidding zone configuration

In addition to simulating zonal markets and redispatch, the model is also used to derive the bidding zone reconfiguration scenarios. As a basis for zonal delineation, hourly marginal supply costs, or locational marginal prices (LMPs) are calculated, considering all transmission constraints and corresponding load flows. LMPs are identical for nodes within fully coupled markets, i.e., where connections are unconstrained. When congestion arises, nodal markets decouple, resulting in different LMPs. Providing an insight regarding the location of transmission bottlenecks, LMPs are widely used in the literature as a basis for deriving zonal delineations. It should be noted that Grimm et al. (2016) demonstrated that zones derived from LMPs do not necessarily lead to optimal, i.e., welfare-maximizing, configurations. Nevertheless, this approach remains prevalent due to its simplicity[25] and is used by ACER to propose zonal reconfiguration candidates in the BZR process.

To cluster nodes into zones based on LMPs, this study employs Ward's criterion, which minimizes the sum of squared differences among the LMP time series for all nodes. Nodes with similar hourly LMPs are grouped into the same clusters. Following Felling and Weber (2018), the clustering algorithm is constrained to only cluster nodes that are physically connected.

3.3.3. Scenario

The market and grid model represents the 13 European countries integrated into FBMC, along with important neighboring countries such as Denmark, Sweden, Norway, Italy, and Switzerland, which are coupled via NTCs. The model includes the transmission grid (220 kV and 380 kV), reduced from 1,063 to 533 nodes (as of 2021) using a grid reduction algorithm developed by Biener and Garcia Rosas (2020). Transmission grid capacity expansion is exogenous and follows the *Ten Year Network Development Plan 2022* (TYNDP) published by European

[24]Redispatch costs in this study differ from those reported annually by the German grid regulation agency, as the latter report compensation payments for down-regulated units as redispatch costs. In the present analysis, these compensation costs are accounted for in the consumer wholesale costs from zonal market clearing.

[25]The computational complexity of endogenously optimizing zone delineation is demonstrated, for example, in Lété et al. (2022).

electricity and gas grid operators (ENTSO-E and ENTSO-G, 2022) and the *Grid Development Plan* (NEP) published by the German TSOs (50Hertz et al., 2022). Note that countries connected by NTCs are modelled as single nodes, without intra-zonal grid restrictions. The transmission grid is depicted in Figure 3.2.

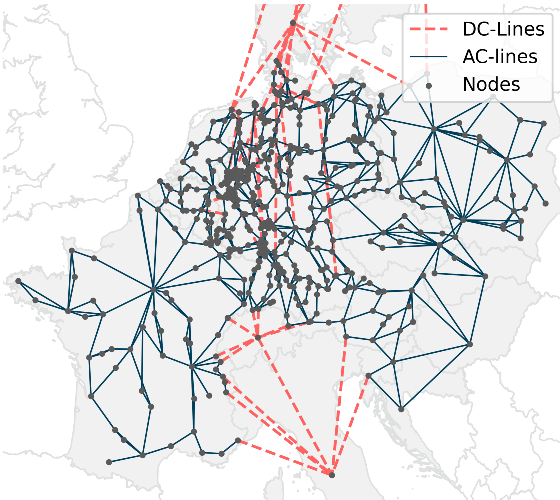


Figure 3.2.: Map of the transmission grid (Zinke, 2023)

The model is initialized with data for 2021, as described in Zinke (2023), and applied in this study for the year 2030. It simulates the zonal dispatch and redispatch at an hourly resolution for the weather year 2009, which is considered a typical weather year according to ENTSO-E and ENTSO-G (2022). Demand and power plants in all countries except Germany follow the *National Trends* scenario from the the TYNDP (ENTSO-E and ENTSO-G, 2022).

The scenario for Germany reflects current legislation where applicable, such as renewable energy capacity targets. The regional distribution of renewables is based on assumptions from 50Hertz et al. (2022). Furthermore, the scenario accounts for the phase-out of coal and nuclear power plants as according to *Act to Reduce and End Coal-Fired Power Generation* (KohleAusG) and government plans to phase out lignite in North-Rhine Westphalia by 2030 (BMWK, 2022b). Electrolyzer capacity aligns with the German Hydrogen Strategy, while regional distribution reflects announced electrolyzer projects. The capacity for large-scale batteries is taken from the TYNDP scenario, with batteries distributed to the largest demand nodes where sufficient grid connections are likely in place (see Zinke (2023)). Capacity additions for open-cycle gas turbines (OCGT) follow recent proposals to add 5 GW until 2030 (BMWK, 2024). Additionally, it is assumed that 15 GW of combined cycle gas turbines (CCGT) are added, which corresponds to capacity "in planning" or "under construction" in the scenario for the upcoming new grid development plan Bundesnetzagentur (2024).

Given the uncertainty regarding siting, the new gas-fired capacities are assumed to be connected at sites where coal, lignite, and nuclear power plants are phased out, utilizing existing grid capacity. Annual demand for Germany is based on the TYNDP's *National Trends* scenario and distributed according to population shares (residential) and gross value added (industrial and commercial). Demand in other countries is distributed based on population. Table B.2 in B.1 depicts demand assumptions.

Assumptions on fuel price development follow the *Stated Policies* scenario in IEA (2022) and are listed in Table B.3 in B.1. Carbon is priced at 100 EUR/t.

3.4. Results

3.4.1. Bidding zone configuration

Figure 3.3 presents the three considered bidding zone configurations. Figure 3.3 (a) shows the single German bidding zone as it is today. Clustering locational marginal prices into two zones, a split between the North (N) and the South (S) emerges around the 53rd latitude (Figure 3.3 (b)). In the case of three zones, shown in Figure 3.3 (c), the North zone is split into a North-Western (NW) and a North-Eastern (NE) zone, while the South zone is the same as in the two-zone setup. Notably, the two-zone and three-zone setups closely align with options *DE2 1* and *DE3 12* discussed in ACER's bidding zone review (ACER, 2022).

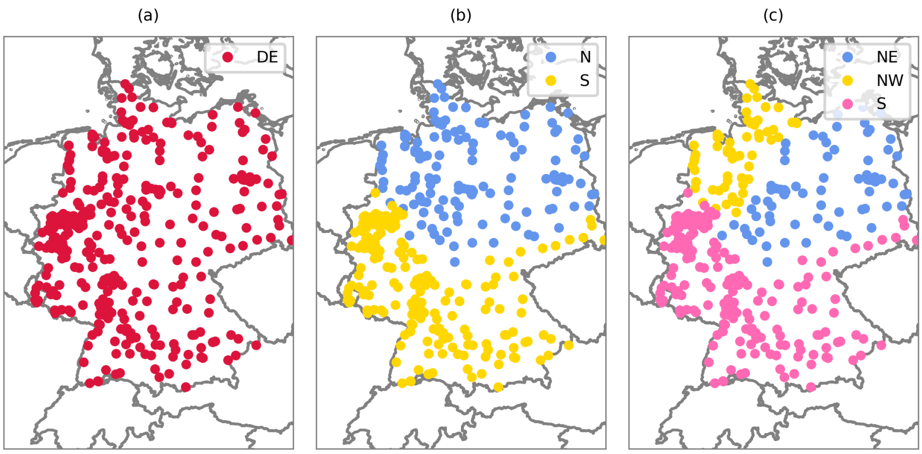


Figure 3.3.: Zonal configuration for (a) the single bidding zone (b) two bidding zones and (c) three bidding zones

3.4.2. Electricity Prices and Consumer Rents

Splitting the German bidding zone introduces additional transmission constraints into the market, restricting trade between market participants. As a result, electricity wholesale costs for inflexible consumers increase significantly, with net cost rises of 1.6 bn EUR and 1.8 bn EUR, for two and three zones respectively. These cost increases correspond to reductions in consumer rents[26]. The effect entails both, the desired transmission capacity reduction implemented to reduce congestion, and frictions from inaccuracies and security margins in the approximative transmission capacity allocation under FBMC.

The cost changes vary across zones, as prices differ between them. Table 3.2 lists demand-weighted average wholesale electricity prices for inflexible consumers alongside ΔCR. Compared to the single zone setup, both splitting scenarios reduce prices in the North while increasing prices in the South. This leads to higher consumer rents in the North and lower rents in the South. Since most demand is concentrated in the South, the overall effect is a rent decrease.

Under the three-zone configuration, which further divides the North into a North-East and a North-West zone, price increases in the South are less pronounced. At the same, prices in the North are higher than under a two-zone split. This is especially the case for the North-East zone, where prices almost converge with the South. This occurs because resolving internal congestion in the North frees up transmission capacity for trade with the South by reducing loop flows on interconnectors. As a result, more consumers face higher prices, reducing consumer rents further.

Table 3.2.: Average demand-weighted electricity prices and ΔCR compared to the single bidding zone in 2030

		Electricity price [EUR/MWh]	ΔCR [bn EUR/a]
Single zone	DE	66.9	-
Two zones	DE	68.2	-1.6
	N	56.5	2.5
	S	76.5	-4.1
Three zones	DE	68.7	-1.8
	NE	70.0	-0.2
	NW	56.9	1.0
	S	72.3	-2.5

Regarding effects on an individual household level, it is crucial to note that wholesale electricity prices account for only a fraction of household electricity prices. Table 3.3 illustrates electricity wholesale cost changes for average house-

[26] As mentioned in Section 3.3, costs for flexible demand, such as storage and electrolysis, are excluded from consumer surplus calculations and instead considered in producer rents.

holds with more than three persons and single-person households.[27] For them, the wholesale cost changes are negligible. However, for industrial consumers wholesale prices constitute a larger share of total costs, and consumption volumes are substantially higher, making price increases more impactful (c.f. Tiedemann et al., 2024).

Table 3.3.: Exemplary wholesale electricity cost changes by consumer group and bidding zone setup in 2030 compared to the single bidding zone setup

		> 3 persons [EUR/a]	single person [EUR/a]
Two zones	DE	7.5	4.7
	N	-56.0	-35.0
	S	52.5	32.8
Three zones	DE	10.2	6.3
	NE	17.0	10.6
	NW	-54.1	-33.8
	S	29.5	18.4

3.4.3. Producer Rents

Total producer rents decline when splitting the bidding zone, by 2.6 bn EUR and 1.9 bn EUR for the two-zone and three-zone splits, respectively. However, the impacts vary across zones and technologies. Figure 3.4 shows producer rent changes under both split scenarios compared to a single bidding zone. Producer rent decreases in the North, driven by lower prices, while it increases in the South. This reflects the assumed distribution of power plants, with wind power rents in the North negatively impacted and those of conventional power plants and PV in the South rising.

Producer rent losses for wind are highest under the two-zone setup, as the majority of wind generation is concentrated in the North, resulting in price cannibalization - high simultaneous generation exceeding demand causing prices to drop and market-based curtailment to increase. Table 3.4 lists market-based curtailment of renewables across the different zonal configurations. Splitting the North into two zones in the three-zone setup enhances North-South trade, reducing market-based wind curtailment and increasing generation and revenues. Consequently, wind producer rents improve under the three-zone split compared to the two-zone split, partially mitigating producer rent losses. PV rents, however, benefit slightly more from the two-zone setup due to higher prices in the South, where most PV capacity is located.

[27] Average consumption data for 2021 is taken from Statistisches Bundesamt (2023) and amounts to 5,411 kWh/year for households with more than three persons and 3,383 kWh/year for single-person households.

Table 3.4.: Market-based curtailment of RES by bidding zone setup in 2030

		PV [TWh/a]	Wind onshore [TWh/a]	Wind offshore [TWh/a]
Single zone	DE	6.9	16.3	4.6
Two zones	DE	9.0	27.6	6.5
	N	3.7	24.6	6.5
	S	5.2	2.9	-
Three zones	DE	14.3	20.5	2.3
	NE	8.1	10.1	1.2
	NW	1.5	7.1	1.1
	S	4.7	3.3	-

For storage technologies, price volatility and the opportunity for arbitrage determines surpluses. Both bidding zone split configurations decrease volatility in the South, where prices are less influenced by wind intermittency in case of the split. Therefore, rents achieved by pumped storage facilities, which are only located in the South zone, decrease compared to a single bidding zone.

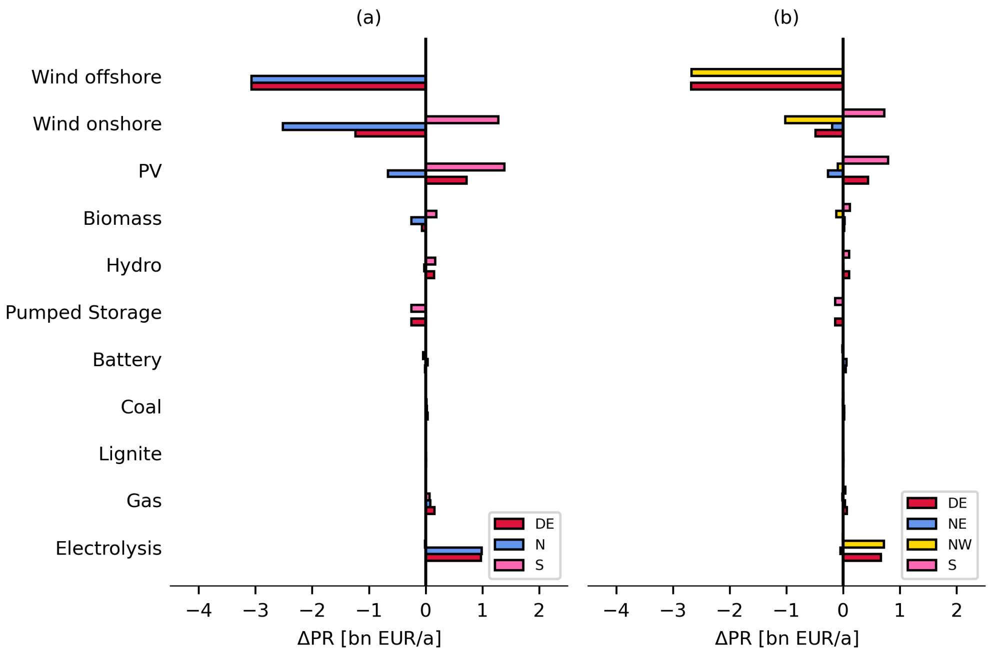


Figure 3.4.: ΔPR for (a) two zones and (b) three zones compared to the single bidding zone setup by technology in 2030

Batteries, which are located at the nodes with the highest demand, benefit from increased volatility in the North and suffer from decreased volatility in the South compared to the single bidding zone setup. Total rents achieved by batteries decrease in the two-zone setup because rent decreases in the South zone overcompensate rent increases in the North zone. Contrarily, batteries benefit in the three-zone setup. This is related to changed price dynamics in the North-East zone: Since there is access to inexpensive wind energy, batteries can charge there at low prices. The North-Eastern zone also has high demand around the capital region so that batteries can discharge at high prices. Additionally, there is a certain convergence[28] of prices between the South and the North-East zone, as trade increases. This leads to batteries in the South zone selling electricity at higher prices while still charging at low prices.

Electrolyzers, which are included in producer rents even though they produce hydrogen instead of electricity, benefit in both bidding zone split scenarios because they are assumed to be located in the North, where prices are lower. Naturally, they benefit more from one Northern price zone with low prices than from a East-West split in the three-zone setup, which leads to higher prices in the North-East.

All in all, producer rent effects are largely driven by RES, which constitute the majority of capacity in the 2030 scenario. Price cannibalization, influenced by regional allocation, significantly impacts RES producer rents.

3.4.4. Subsidies

Renewable technologies and newly installed gas power plants are subsidized to incentivize investment, with subsidy expenditure closely tied to producer rents. However, subsidies also account for the recovery of annualized investment costs, including historical RES installations that still fall under the subsidy scheme.

For the single bidding zone, subsidy expenditure for renewables amounts to 24.1 bn EUR. For both bidding zone split scenarios, renewable subsidy expenditure increases by 3.5 bn EUR and 2.9 bn EUR for the two-zone and three-zone setups, respectively, compared to the single bidding zone. This is primarily due to lower revenues for wind power plants in the North, where concentrated capacity leads to price cannibalization. The three-zone setup mitigates this slightly, as increased North-South trade raises prices in the North East zone. For PV, subsidy expenditure decreases under a bidding zone split since most capacity is located in the South, where higher prices increase revenues. This effect is most pronounced in the two-zone configuration.

Subsidy expenditure for newly installed gas power plants amounts to 2 bn EUR under the single bidding zone setup, decreasing by 40 million EUR and 17 million EUR in the two-zone and three-zone splits, respectively. This reflects assumptions that new gas plants will be added mainly in the South.

[28] North-South price correlation lies at 0.61 in the two-zone setup, while price correlation between the North-Eastern and Southern zones lies at 0.86 in the three-zone setup. Correlation between the North-West and the South is at 0.7. Correlation between North-West and North-East is 0.79.

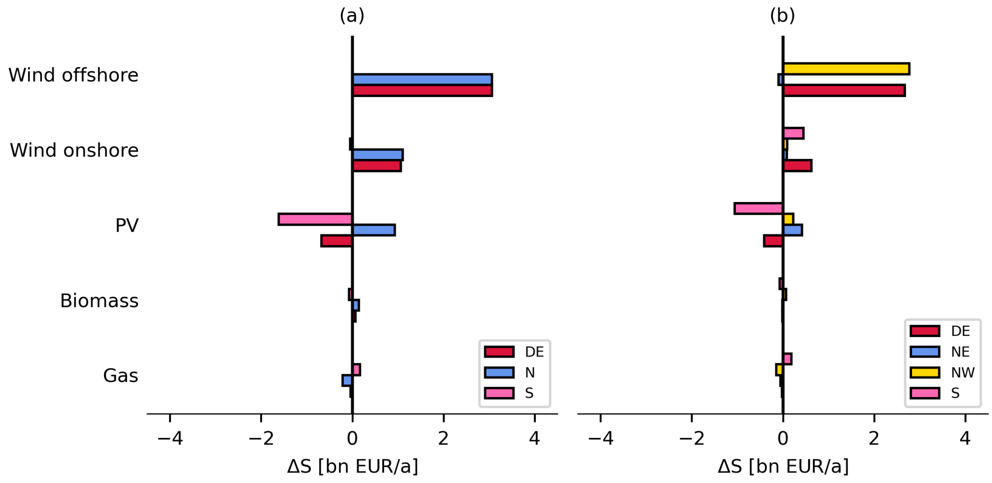


Figure 3.5.: ΔS for (a) two zones and (b) three zones compared to the single bidding zone setup by technology in 2030

Overall, splitting the German bidding zone increases subsidy expenditure, with a greater increase in the two-zone configuration compared to the three-zone setup. Policymakers should also consider the potential interaction between subsidy scheme design and a bidding zone split.

3.4.5. Congestion Rent

Splitting the German bidding zone generates significant congestion rent in the market clearing, amounting to 2.3 bn EUR and 2.8 bn EUR for the two- and three-zone configurations, respectively, in the 2030 scenario. Most of this revenue arises within today's single German bidding zone, while congestion rents at cross-border lines contribute only a small share. Notably, congestion rents in the rest of Europe decrease as internalizing intra-German congestion reduces congestion on Germany's cross-border lines. Under Regulation (EU) 2019/943, revenues from cross-zonal transmission capacity allocation must be used for congestion management and grid expansion, suggesting that these rents could be used to lower network fees and thus electricity consumption costs.

3.4.6. Redispatch

The bidding zone split significantly reduces redispatch and grid-based renewable curtailment, leading to lower redispatch costs. Table 3.5 summarizes the results.

Most redispatch cost savings are realized in the two-zone split as the primary bottleneck between Northern and Southern Germany is internalized in the market. Additional reductions in redispatch costs occur with a three-zone split, particularly addressing congestion between the North-West and North-East. The

Table 3.5.: Redispatch costs and curtailment by bidding zone setup in 2030

		ΔRD [bn EUR/a]	Curtailment Wind [TWh/a]	Curtailment PV [TWh/a]
Single zone	DE	-	12.8	7.7
Two zones	DE	-1.0	5.5	6.1
	N	-	4.3	1.5
	S	-	1.2	4.6
Three zones	DE	-1.7	4.7	4.7
	NE	-	0.3	0.4
	NW	-	3.2	0.3
	S	-	1.2	4.0

enhanced North-South trade in this configuration also alleviates PV curtailment in the South zone during sunny hours when electricity is traded from South to North, as already found in Czock et al. (2023). All in all, the results show that the three-zone setup reflects the transmission grid better than the two-zone setup.

3.4.7. Static Welfare Balance

Figure 3.6 summarizes the results on rents and subsidy expenditure presented in the previous sections and illustrates the resulting total static welfare impact of the two bidding zone split scenarios for the year 2030 and for the given representation of frictions. Total static welfare changes are modest. Static welfare decreases by 0.2 bn EUR/a and increases by 0.7 bn EUR/a for the two-zone and the three-zone setup, respectively. This corresponds to 1.6 % and 4.4 % of total supply costs in the single German bidding zone. In the face of frictions in redispatch and transmission capacity allocation, welfare gains (increased congestion rents and reduced redispatch costs) in the two-zone setup cannot offset the losses in consumer and producer rents induced by the new transmission constraints. Figure 3.6 illustrates the overall welfare balance.

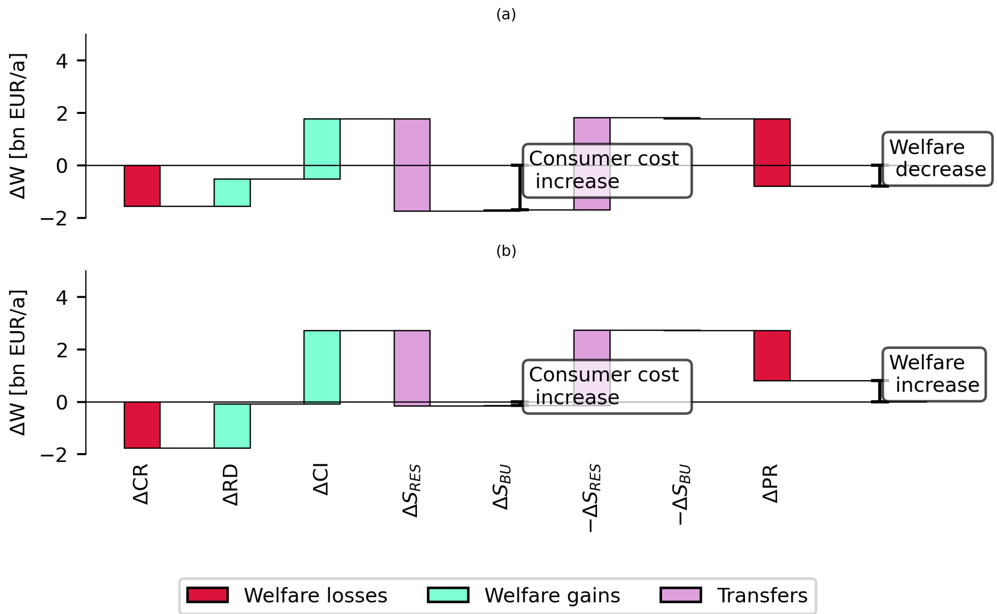


Figure 3.6.: Static welfare balance for (a) two zones and (b) three zones compared to the single bidding zone setup in 2030

Additionally, Figure 3.6 highlights the distribution effects of the considered bidding zone split scenarios. In both setups, consumer costs consisting of consumer rents (CR), redispatch costs (RD), congestion income (CI), and subsidies (S), increase. Especially in the two-zone setup, rising wholesale costs and subsidy expenditure under a bidding zone split cannot be offset by redispatch savings and increased congestion rents. In the three-zone setup, decreased redispatch costs and increased congestion income mitigate consumer cost increases from rising wholesale costs and subsidy expenditures almost completely. Producers benefit from subsidies, which compensate the losses in producer rents (PR) in both considered bidding zone setups. However, individual consumer cost and producer rent vary significantly between zones, as well as (in the case of producer rent) between technologies, as detailed in earlier sections.

3.4.8. Sensitivity Analyses

As discussed in section 3.2, there is no consensus in existing literature on the effects of splitting the German bidding zone, with variations likely driven by differences in scenarios and the representation of frictions. To illustrate the influence of these factors, three sensitivity analyses are conducted.

The first two analyses focus on scenario choice and consider slower wind energy and grid expansion respectively, reflecting Germany's historical challenges in meeting grid and capacity expansion targets (c.f. Zinke, 2023, who conduct similar sensitivity analyses on redispatch costs). Specifically, wind capacity expansion between 2021 and 2030 is halved and all grid expansion projects are delayed by one year to account for these delays. The third analysis examines the effects of changes in redispatch frictions, analyzing a setup where batteries are fully integrated into redispatch, thereby decreasing frictions in redispatch.

Figure 3.7 illustrates the static welfare changes (relative to the respective single bidding zone case) under these sensitivity analyses.

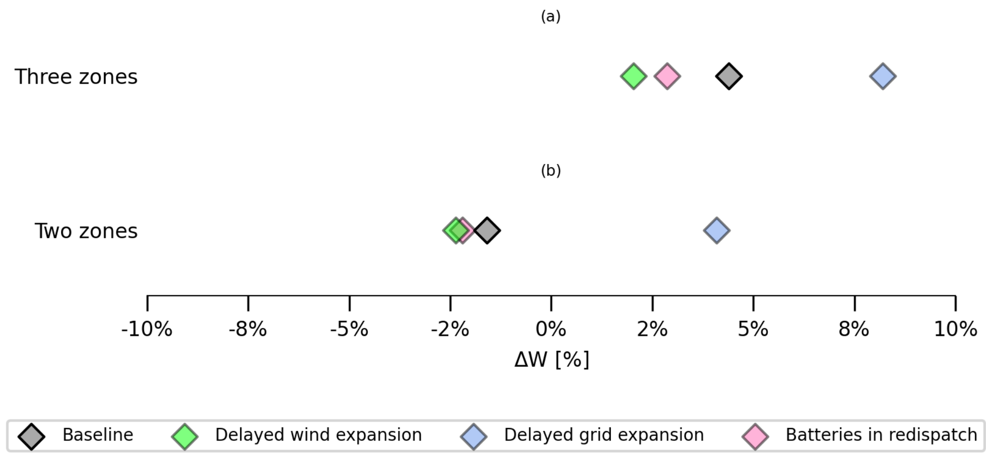


Figure 3.7.: Welfare changes in sensitivity analyses for (a) two zones and (b) three zones, compared to the respective single bidding zone setup in 2030

In the scenario with delayed wind capacity expansion, welfare losses in the two-zone setup are higher, while welfare gains in the three-zone setup are lower than in the baseline scenario. Comparing with the respective single-zone setup, welfare decreases by 2.4 % in the two-zone setup and increases by 2.0 % in the three-zone setup. This is due to the fact that with reduced wind energy capacity, grid congestion is less severe to begin with, and a split cannot decrease redispatch costs as much as in the baseline scenario. Contrarily, in the case of delayed grid expansion, congestion is exacerbated, and the introduction of a bidding zone split can result in significant redispatch cost savings. Overall, welfare improves for both the two-zone and three-zone splits, with the three-zone split proving to be far superior due to its ability to address both North-South congestion and congestion between the North-East and the North-West.

The third sensitivity analysis investigates the effect of removing frictions from redispatch by assuming full participation of batteries in redispatch. This reduces the static welfare gains from bidding zone splitting: The static welfare gain under the three-zone setup diminishes, while the welfare loss under the two-zone split increases. The reason is that in the single bidding zone setup, redispatch costs are already lower because redispatch is more efficient. Consequently, by partially removing frictions in redispatch, the potential redispatch cost savings are reduced, while other welfare parameters remain unchanged from the baseline.

3.5. Discussion

3.5.1. Market results

When comparing the results of this study with existing literature, one notable difference relates to electricity prices in the two-zone setup. The price differences between zones in this study reach up to 20 EUR/MWh, which is higher than what has been reported in existing literature. Price differences are impacted by the aforementioned choices in exact bidding zone delineation and FBMC parameters including frictions. Conclusively, direct comparisons with other studies are limited by differences in grid modeling methods and scenario years and no prior study examines a 2030 scenario with a high-resolution FBMC grid model of the European electricity sector. Key factors driving the price differences in this scenario include the high concentration of wind power in the North zone(s), leading to low prices there. In the South zone, high marginal costs of gas power plants (exceeding 120 EUR/MWh for OCGTs) lead to high prices when PV is unavailable. In the case of three zones, prices between the zones converge. Comparing the modelled electricity prices to future power product trades on EEX spot, the results generally seem well in range. For trades carried out in 2024, a volume-weighted average price of 67 EUR/MWh emerges for base products and 79 EUR/MWh for peak products.

Another difference to existing studies concerns the subsidy expenditures for RES. The findings on subsidy expenditure generally align with EWI (2024), which forecasts 19.4 bn EUR in subsidy expenditure for 2029 under a single bidding zone, compared to 24.1 bn EUR for 2030 in this study. Regarding the impact of a bidding zone split, Tiedemann et al. (2024) report trends of increased subsidy needs for wind in a scenario with two bidding zones in 2030. However, by using exemplary reference values and by omitting past installation costs, they arrive at significantly lower subsidy expenditures. They do not investigate offshore wind subsidies. While offshore wind investors have recently bid reference values of zero, this study indicates that steep capacity increases by 2030, combined with a bidding zone split, exacerbate price cannibalization, necessitating significant subsidies. However, Tiedemann et al. (2024) raise the important point of coordinating price incentives from a potential bidding zone split with the design of the EEG subsidy scheme. While this study essentially assumes that renewable producers are compensated for the difference between zone-specific market values and their reference values, Tiedemann et al. (2024) argue that to maintain price signals and to incentivize renewable capacity in high-price zones, applying a uniform market value across zones would be necessary. They show that applying a uniform market value would potentially increase subsidy expenditure even further.

3.5.2. Welfare and frictions

The quantitative results indicate that, in the presence of frictions in redispatch and transmission capacity allocation, splitting the German bidding zone does not guarantee static welfare increases. Instead, static welfare depends on the bidding zone configuration, scenario and the frictions. For the 2030 baseline scenario, the considered two-zone configuration leads to slight losses, while the three-zone configuration results in welfare gains. The static welfare losses associated with the two-zone split may seem counterintuitive at first. The North-South split internalizes a significant transmission bottleneck, significantly reducing redispatch volumes and, consequently, costs, which supports one of the main arguments in favor of splitting the bidding zone. However, compared to the single bidding zone, trade within Germany is restricted by the new transmission constraint. This results in increased generation costs in Germany, leading to lower welfare in the zonal market clearing. Redispatch cost reductions cannot fully compensate for the welfare losses in the zonal market clearing in the investigated two-zone split scenario. In contrast, the three-zone setup increases static welfare for two reasons: first, intra-zonal congestion between the North-East and the North-West is internalized in the market, and redispatch costs decrease further. Second, loop flows on the lines connecting the North and the South are alleviated as congestion in the North decreases. This allows for more trade between the South and the North(-East), lowering total generation costs and increasing welfare.

The results are contingent on the considered bidding zone configurations and how well they reflect the transmission grid and the distribution of generation and demand, i.e. congestion. This is also highlighted by the sensitivity analyses, where changes in wind generation capacity and grid expansion lead to significant changes in static welfare. This finding aligns with results in Zinke (2023), who shows that redispatch cost reductions are significantly higher if bidding zones are regularly adjusted to reflect changing grid constraints in the face of transmission capacity expansion. This poses several challenges for policymakers looking to increase welfare by splitting bidding zones: Although it may enhance static efficiency, regular reconfiguration of zones may potentially prevent meaningful investment signals and may therefore impact dynamic welfare. This is aggravated by the fact that bidding zone reconfiguration has an estimated lead-time of three to five years, whereas the most recent formal BZR process took over five years from the definition of assumptions in 2020 to the publication of the quantitative results in 2025. Indeed, the lengthy process prohibited a clear recommendation: Although they find that from a European perspective, splitting the German bidding zone marginally increases static welfare[29], the authoring TSOs refrain from recommending a split because assumptions on fuel prices and demand and generation development were outdated by the time of publication. Additionally, the calculated target year (2025) is regarded to not be meaningful for potential

[29] Static welfare increases with the number of zones Static welfare increases are less than 1% of European supply costs.

implementation years (around 2030) (c.f. ENTSO-E, 2025). To enable informed decision-making, further research should therefore address the dynamic impact of bidding zone splitting in the face of power system changes, such as planned transmission capacity expansion.

Next to zone configuration, the results presented in this paper are specific to the representation of frictions in the model. First, this relates to frictions in redispatch, which are modeled by limiting the participation of intermittent RES, demand, batteries, and other zones to approximate real-world redispatch procedures. If redispatch were more efficient, for example, with the participation of additional technologies or demand, a split might be less favorable. This is highlighted by the sensitivity analysis modeling full battery participation in redispatch. If batteries were fully integrated into the redispatch process, the benefits of a split would diminish. However, it is important to note that the effects of battery participation are highly sensitive to their location in the transmission grid, as demonstrated by Czock et al. (2023). Furthermore, it is unclear how efficiency gains from integrating batteries into redispatch can be achieved in practice. The model used in this study assumes optimized charging and discharging decisions for redispatch. In reality, although TSOs receive day-ahead generation schedules, they currently lack the means to preemptively coordinate these decisions. Instead, efficient coordination of batteries with regard to congestion management would require regionally differentiated price signals reflecting grid constraints. A potential solution could involve the creation of a redispatch market, although this would expose the market to "inc-dec gaming," as discussed by Hirth and Schlecht (2018). A bidding zone split, too, creates differentiated price signals that allow batteries to react to congestion. These price signals can only reflect those transmission constraints internalized by the split and are subject to frictions in transmission capacity allocation (see below). Nonetheless, when interpreting the welfare changes highlighted in the sensitivity analysis with full participation of batteries, it must be kept in mind that efficiency gains from battery participation may not fully materialize in the single bidding zone case due to lack of coordination.

Moreover, the results are contingent on the chosen redispatch modelling method. This study employs an ex-post optimization of the nodal dispatch, whereas other studies, such as Fraunholz et al. (2021), apply artificial penalties to ensure that only physical violations of grid infrastructure are resolved. The approach adopted here may potentially overestimate redispatch volumes. However, it should be noted that while penalty-based methods minimize redispatch volumes, determining the appropriate penalty is a non-trivial task. Additionally, the modelling approach used in this paper does not account for the proportional depreciation of capital and opportunity costs that generators incur due to redispatch. These factors, which are accounted for in real-world redispatch and reimbursed to generators, are not reflected in the redispatch cost calculations here. As a result, the simplified representation of redispatch in this study likely overestimates redispatch volumes and underestimates associated costs. A more detailed evaluation of various redispatch modelling approaches and their respective impacts is warranted. This paper offers preliminary insights into the impact of varying redispatch efficiencies, but further research should explore this topic more comprehensively, both in terms of modeling techniques and the potential efficiency gains achievable by real-world redispatch.

Second, regarding frictions in transmission capacity allocation, it must be noted that the representation of FBMC employed in this study also involves several simplifications, which are common in quantitative studies. For instance, this paper assumes fixed security margins and generalized assumptions regarding GSKs. In reality, TSOs have more detailed information about the grid and derive GSKs and security margins from flow forecasts two days ahead (Creos et al., 2020). Further research should address the impact of flow-based parameter choice and grid modelling methods in general on welfare effects of a bidding zone split.

Finally, this study does not assess frictions associated with potentially limited liquidity in smaller bidding zones. Further research on the potential welfare impact is needed, considering opportunities for (proxy-)hedging on neighboring markets, i.e. by analyzing covariance of prices while accounting for effects of zone configuration on interconnector capacity.

3.5.3. General limitations

Additionally, several limitations inherent to optimization-based electricity market modelling have to be considered when interpreting the numerical results obtained in this study. First, the market and grid model used to simulate zonal markets relies on the following assumptions: perfect foresight, no transaction costs, perfect markets, and inelastic demand. Only if these assumptions hold, the mathematical duality between a central planer problem and the profit-maximization of symmetric firms, which allows for the quantification of welfare, holds.

3.6. Conclusion

This study contributes to the ongoing debate on splitting the German bidding zone. Existing literature, which lacks consensus on welfare and price effects has so far been limited to the analysis of two zones and frictions have not been considered explicitly. The research gap is addressed by a detailed quantitative analysis of static market and welfare impacts using a state-of-the-art grid and market model with flow-based market coupling for a 2030 scenario. The model is used to investigate a North-South split into two zones and a three-zone split, which splits the North-East and North-West. Key quantitative findings are:

- Given frictions in transmission capacity allocation and redispatch, static welfare increases by 4 % for the three-zone split, while it decreases by 2 % for the investigated two-zone split.
- Consumer wholesale costs decrease in the North while they increase in the South, leading to overall consumer rent decreases.
- Splitting the bidding zone reduces redispatch costs and increases congestion income, thus partially mitigating consumer cost increases if cost changes are passed on via grid fees.
- Price cannibalization in the North zone(s) leads to decreased revenues for wind power, which increases subsidy expenditure and therefore consumer costs.
- Static welfare is highly sensitive to scenario choice and representation of frictions.

All in all, total static welfare impacts of a bidding zone split in 2030 are modest, while distribution effects are significant. Especially in the two-zone setup, consumers are exposed to higher costs than in the single bidding zone setup. Higher market granularity with three zones improves static welfare and mitigates distribution effects compared to two zones.

Conclusively, splitting the German bidding zone does not guarantee welfare gains and welfare outcomes depend on the exact configuration of the zones, the scenario and frictions in redispatch and transmission capacity allocation. Additionally, policymakers should weigh the (uncertain) static welfare effects against transition costs of a bidding zone split, which have been estimated to lie around 1.5 bn EUR (one-off costs) in Compass Lexecon (2023). Additionally, they should consider potential impacts on market liquidity, which are uncertain according to Compass Lexecon (2024). Especially in the case of three zones, which is found to be favorable over a two-zone split in this study, smaller markets may potentially lead to lower liquidity. Furthermore, the interplay with existing policies such as the RES subsidy scheme or the planned capacity mechanism need to be analyzed. Finally, policy-makers need to consider dynamic effects of bidding zone splitting given the trade-off between accurate representation of congestion and defining stable bidding zones.

In light of the complexity, policymakers should evaluate whether alternative mechanisms such as increasing redispatch efficiency, albeit with new coordination challenges, could serve a similar purpose as a bidding zone split - potentially at lower transaction costs and distribution effects.

Further research is needed to assess the market and welfare impacts of splitting the German bidding zone from a pan-European perspective. Still, this study highlights the importance of thorough analysis for any bidding zone reconfiguration, including ongoing discussions for e.g. Italy, France, and Sweden, as static welfare gains cannot be assumed automatically.

4. A heated debate - The future cost-efficiency of climate-neutral heating options under consideration of heterogeneity and uncertainty

4.1. Introduction

Heating homes is one of the major sources of greenhouse gas emissions in regions with cold climates, and little progress has been made on curbing these emissions globally (IPCC, 2022). On the national level, some countries have developed clear strategies for heat decarbonization: for instance, Denmark, Finland, and Sweden use district heating to supply low-carbon heat to many households, partially complemented by water or ground-source heat pumps for detached houses, while France and Italy focus on water and air-sourced heat pumps (Kerr and Winskel, 2021, Sovacool and Martiskainen, 2020, Witkowska et al., 2021). Meanwhile, other countries, including Germany and UK, have seen heated policy debates on the decarbonization pathways and corresponding regulation of the heating sector (Meakem, 2023, Thomas, 2023).

In Germany, for instance, where two-thirds of residential buildings are heated with fossil fuels today (c.f. BDEW, 2023), legislators proposed a minimum renewable energy requirement for new heating systems under the *Law on Building Energy* (German: GEG). This would have effectively banned new combustion boilers and mandated electric heat pumps. Following debates over the high investment costs of heat pumps and the lack of technology openness, the requirement was broadened to include combustion boilers fueled with green gases. Recognizing uncertainties in infrastructure availability, policymakers tied the requirement's implementation to the publication of municipal heat plans, which are to be developed by 2026-28, depending on municipality size[30]. This shifts responsibility for determining cost-efficient, climate-neutral heating solutions to the municipalities.

How to achieve climate-neutral residential heating can be a complex question. Although the majority of existing studies conclude that electric heat pumps are advantageous over green gases for residential heating (c.f. Rosenow, 2022), they also reveal that there is great heterogeneity and uncertainty in many of the relevant input parameters. First, buildings are heterogeneous in size and insulation,

[30]C.f. GEG and *Law on Heat Planning and Decarbonization of Heating Networks* (German: WPG)

and settlements differ by heating density (Heitkoetter et al., 2021, Kotzur et al., 2020). Second, there is a variety of climate-neutral heating technologies based on decarbonized electricity or synthetic fuels (Ruhnau et al., 2019), and the possibility to deploy these technologies either decentrally or centrally, connected to heating grids (Jimenez-Navarro et al., 2020). Third, future costs of green energy commodities like electricity, hydrogen, or synthetic natural gas (SNG) (Liebensteiner et al., 2023, Moritz et al., 2023), the future costs of technologies like heat pumps (Chaudry et al., 2015), and the future level of insulation are uncertain. Finally, infrastructure costs and related grid fees are also uncertain for electricity, hydrogen, and district heating due to potential reinforcement, retrofit, and expansion requirements and for synthetic natural gas due to potentially declining demand (Kopp et al., 2022, Pena-Bello et al., 2021). Previous studies have addressed these factors individually (e.g. Billerbeck et al., 2024, Czock et al., 2025, Kotzur et al., 2020) analyze building heterogeneity, (Chaudry et al., 2015, Czock et al., 2025, Knosala et al., 2022) consider fuel price uncertainty, and (Billerbeck et al., 2024, Lux et al., 2022) model infrastructure (see C.1 for a detailed literature review). Yet, a systematic approach that jointly analyzes the various heterogeneities and uncertainties is lacking.

This article aims to disentangle the effect of these heterogeneities and uncertainties on the cost efficiency of heating options. To this end, we calculate the future levelized cost of heating (LCOH) for a wide range of input assumptions that reflect the heterogeneity of building types, settlement structures, and technology options in great detail. Specifically, we consider different supply temperatures to reflect heterogeneity in building insulation, four different settlement types to reflect heterogeneity in heat density, and eleven different heating options. The technology options include decentralized air-to-air (AtA) heat pumps as well as decentrally and centrally deployed air-to-water (AtW) and water-to-water (WtW) heat pumps, and electric, hydrogen, and synthetic natural gas (SNG) boilers (see Methods for the derivation of this selection). Furthermore, we conduct a variety of sensitivity analyses on uncertain future electricity, hydrogen, and SNG prices, grid fees, and technology costs. Motivated by the recent policy debate and ongoing heat planning processes, we use Germany as a case study for our analysis. While uncertainty prevents us from drawing definitive conclusions on the future cost-efficiency of different climate-neutral heating options, our approach enables us to provide insights into the conditions under which the different options would be most economical.

With this, we make three distinct contributions to the existing literature. First, we capture building heterogeneity and uncertainty regarding fuel prices and infrastructure costs in one analysis. Second, we systematically compile a detailed dataset on heating technology costs by system size, estimated future grid fees or costs by infrastructure and settlement type, and estimated future energy prices by energy carrier, which may prove helpful beyond the present analysis. Third, we conduct extensive sensitivity analyses on the cost efficiency of climate-neutral heating technologies. Our results can help assess the robustness

Table 4.1.: Reasons for heterogeneity and uncertainty of investigated parameters

Group	Parameter	Heterogeneity	Uncertainty
Buildings and technology	Investment cost	Installed equipment, installation complexity, building sizes	Cost degression of heat pumps
	Supply temperature	Building insulation, size of radiators	Building refurbishment
Prices	Electricity price		Cost and availability of renewable energy, other demand, hydrogen price
	Hydrogen price		Production cost degression, available import countries and transport modes
	SNG price		Production cost degression, available import countries and transport modes, hydrogen price
Infrastructure	Electricity grid cost	Density of electricity demand and other settlement properties	Increase due to RES integration and new demand peaks, unclear if utilization de- or increases
	Hydrogen grid cost	Density of hydrogen demand and other settlement properties	Share of newly constructed vs. retrofitted pipelines, utilization
	SNG grid cost	Density of SNG demand and other settlement properties	Increase due to decreased utilization
	Heating grid cost	Density of heat demand and other settlement properties	Increase due to decreased utilization

of previous academic results and provide guidance for ongoing heat planning as well as related policy debates in Germany and elsewhere.

The remainder of this article is structured as follows: section 4.2 details our methods and data, section 4.3 presents results, examines the impact of uncertainties and heterogeneities on the levelized cost of heating for 10 technologies, and discusses limitations, and section 4.4 concludes with implications for policymakers.[31]

4.2. Methods and data

This paper investigates the future cost-efficiency of climate-neutral residential heating technologies in terms of their LCOH, which is introduced in subsection 4.2.1 below. Hereby, we consider heterogeneity and uncertainty in relevant input parameters concerning buildings and technology, energy prices, and infrastructure, which are summarized in Table 4.1. We continue with a brief overview of these heterogeneities and uncertainties before providing more details in the subsections below.

[31] Supplementary material, such as the code for the LCOH calculation and cost assumptions are available at https://github.com/Michael-Moritz-ewi/A-heated-debate.

Across buildings, heating system costs are heterogeneous because of variances in equipment costs, installation complexity, and building sizes. Additionally, heat pump equipment costs may decrease in the future due to learning. We describe how we capture the different technologies in subsection 4.2.2 and derive cost functions in subsection 4.2.3. Furthermore, buildings are heterogeneous in terms of their building insulation and the size of radiators. This translates to different required supply temperatures, which are relevant for the energy efficiency of heat pumps, as discussed in subsection 4.2.4.

Future fuel prices are highly uncertain for many reasons. Hydrogen and SNG prices depend on the investment costs of renewable energy sources, electrolyzers, and methanation, all of which are likely to decrease in the future. Furthermore, prices in Germany will likely depend on import costs, which vary by the country of origin if transported by pipeline or ship. The uncertainty of electricity prices is related to the costs and availability of renewable energy sources in Germany and interconnected countries, the electricity demand for other applications, and the hydrogen price, which we assume will be used for electricity generation if renewable supply is insufficient. To include fuel price uncertainty, we calculate the LCOH over a range of hydrogen, electricity, and SNG price combinations, derived in subsection 4.2.5.

Infrastructure costs differ among settlement types as settlement-specific characteristics like the spatial distribution, the annual amount, and the peak load of the energy demand shape the costs. We consider four settlement types that differ in terms of building types and heating density, as described in subsection 4.2.6. Within a settlement type, infrastructure costs are heterogeneous and have variance. Moreover, infrastructure costs depend on uncertain developments in the broader energy system, such as the share of heat pumps or the number and spatial distribution of renewable energies connected to the electricity grid. We present our approach for capturing infrastructure cost heterogeneity and uncertainty in subsection 4.2.7.

4.2.1. LCOH calculation

The metric of levelized cost of energy is used to compare the cost of generating energy from different sources or technologies. In this metric, the total costs are normalized per unit of output, discounting over the technology's lifetime. We calculate the levelized cost of heat, i.e., the full costs (in EUR ct 2023) of generating one unit (kWh) of useful heat, for different technologies *tech*, installed capacities c, heat densities d, and supply temperatures T, using the following equation:

$$LCOH_{tech,c,d,T} = \underbrace{\frac{\overbrace{I_{tech,c}\frac{r(1+r)^t}{(1+r)^t-1}}^{\text{CAPEX}} + \overbrace{FOM_{tech,c}}^{\text{fixed OPEX}}}{flh}}_{\text{fixed costs}}$$
$$+ \underbrace{\big(\overbrace{p_{tech}}^{\text{energy}} + \overbrace{g_{tech,d}}^{\text{grid fees}}\big) \overbrace{\frac{1}{\eta^{sys}_{tech,T}}}^{\text{conversion efficiency}} \overbrace{\frac{1}{1-L_{st}}}^{\text{heat loss}} + \overbrace{hdc_d}^{\text{heat distribution}}}_{\text{variable costs}} \tag{4.1}$$

$I_{tech,c}$ are the investment costs of the heating system, depending on the chosen technology *tech* and the capacity c. We calculate the investment costs $I_{tech,c}$ as a function of capacity from equipment and installation costs by designing heating systems according to established planning practices. r is the interest rate, and t is the economical lifetime or depreciation period. $FOM_{tech,c}$ are the fixed costs for operation and maintenance, depending on the heating technology *tech* and the capacity c, and flh are the annual full load hours of the heat generator. p_{tech} is the per kWh energy price for the energy carrier used by *tech*. In the case of SNG, it is expressed as a function of the hydrogen price given the ratio ρ between hydrogen and SNG, i.e. $p_{SNG} = \rho \cdot p_{\mathrm{H_2}}$. $g_{tech,d}$ are estimated future grid fees, which we use to approximate electricity, hydrogen, and SNG infrastructure costs, depending on the heating technology *tech* and the settlement's energy density d. $\eta^{sys}_{tech,T}$ is the conversion efficiency of the heating system *tech* depending on the supply temperature T and is calculated in Equation 4.2. L_{st} are the heat losses of the heating grid in the settlement type st, and hdc_d are the heat distribution costs for a settlement with the heat density d. Both hdc_d and L_{st} equal zero in the case of decentralized heating. All costs refer to EUR 2023.

Based on Equation 4.1, we understand the LCOH as an approximation of heating costs from a system perspective rather than private costs. Thus, we neglect any price components that affect consumer prices but are merely a monetary transfer, such as taxes and levies on energy prices. Furthermore, we neglect existing heating systems and their costs based on the assumption that they will end their lifetime before climate neutrality is reached. By contrast, we implicitly consider existing electricity and gas infrastructures, which have longer lifetimes, because we use projections for future grid fees to approximate infrastructure costs (see Grid fees and costs below).

4.2.2. Heating systems

We calculate the LCOH for ten different technology set-ups that reflect major decarbonization options that are currently discussed (see Table 4.2). We consider four technologies that can be used in centralized and decentralized deployment, namely air-to-water (AtW) and water-to-water (WtW) heat pumps, as well as hydrogen and SNG boilers, and two additional technologies for decentralized deployment only, namely air-to-air (AtA) heat pumps and electric boilers. AtA heat pumps can only be deployed decentrally because they transfer heat directly to indoor air. We do not consider centralized electric boilers because their investment costs are already low when deployed decentrally. Even if investment costs decreased to zero in centralized deployment, heat distribution costs and losses would outweigh investment cost savings.

System flow sheets for all options are provided in Figure C.2. The capacity of the decentralized heat generators is designed to provide both heating and hot water, except for AtA heat pumps, which are combined with an electric boiler for hot water. AtW heat pumps are designed for bivalent monoenergetic operation, i.e., the installed heat pump capacity is kept at a minimum, and peak demands are covered by an electric heater (c.f. Buderus (2019)). For centralized heating, we consider that the capacity of the centralized heat generator is smaller than the sum of the peak heat load of all supplied buildings. This reduction of the aggregated peak is called the simultaneity factor. We use a settlement-type specific simultaneity factor taken from AGFW (2001). Finally, we assume that the temperature of heating grids follows the supply temperature of space heating. Centralized heating with heat pumps is complemented by decentralized electric heaters for hot water if the grid temperature is too low.

Table 4.2.: Technologies and deployment options

Energy carrier	decentralized deployment	centralized deployment
Electricity	Air-to-air heat pump Air-to-water heat pump Water-to-water heat pump Electric boiler	Air-to-water heat pump Water-to-water heat pump
Hydrogen	Hydrogen boiler	Hydrogen boiler
SNG	SNG boiler	SNG boiler

4.2.3. Investment and fixed costs

As an input to the LCOH calculation, we estimate investment costs as a function of installed capacity, including the costs for equipment and installation, thereby accounting for scale effects. For the equipment costs, we collected 555 list prices on the relevant heat generators as well as thermal storage from five manufacturers. For the installation costs, we collected 36 data points from eight installation firms in Germany. Besides the installed capacity, data points vary due to variations in the installed equipment, the time required for installation due to the building heterogeneity, and the heterogeneity of the cost of different installation firms. We fit linear and power functions to the collected data and select the one with the lowest root mean squared error (RMSE). To capture the variance in the observed equipment and installation costs, we generate high-cost and low-cost functions by adding and subtracting 1/3 of the RMSE, respectively (see section C.2 for more detail). For some cost functions, we were unable to obtain sufficient publicly available data and base our assumptions on personal communication with manufacturers and installation firms instead. For instance, we assume that hydrogen boilers are 10% more expensive than natural gas boilers. Furthermore, we add 20% to the equipment costs to account for the contribution margins of installation firms (see C.3). The fixed operation and maintenance costs are parametrized as a function of the installed capacity. Figure 4.1 shows the fitted equipment and installation cost functions, the primary data, the number of datapoints and the R^2 and RMSE of the fitted functions.

As the equipment cost functions are based on historical data, they do not reflect a potential future cost reduction. This is most relevant for heat pumps, which are not yet as widespread as boilers and may benefit from learning effects when deployment increases. The literature reports a wide range of learning rates for heat pumps, with the majority lying between 10 % and 20 % (Henkel, 2011, Heptonstall and Winskel, 2023, ifeu, 2014, Louwen et al., 2018). To capture the uncertainty in future heat pump costs, we conduct a sensitivity analysis with different heat pump equipment cost degressions. We use today's cost (0 % cost degression) as the lower bound for the sensitivity analysis. For the upper bound and baseline values, we calculate cost degression based on heat pump growth factors and learning rates. The upper bound assumes a 60 % cost reduction, derived from a heat pump growth factor of 13 taken from the Net Zero Scenario of the World Energy Outlook (IEA, 2023) and an optimistic 20 % learning rate. The baseline assumes a 30 % cost degression, using a more conservative growth factor of 5 and a 15 % learning rate.

4.2.4. Conversion efficiency

Equation 4.2 shows the calculation of the conversion efficiency of fuel to heat for different heating systems. $SPF_{3\,tech,T}$ is the heat pump's seasonal performance factor including the backup heating rod and η^{boiler}_{tech} is the conversion efficiency of boilers. We assume that the conversion efficiency of boilers does not depend on the supply temperature.

$$\frac{1}{\eta^{sys}_{tech,T}} = \begin{cases} \frac{1}{SPF_{3\,tech,T}} & \text{if } tech \text{ is a heat pump} \\ \frac{1}{\eta^{boiler}_{tech,T}} & \text{if } tech \text{ is a boiler} \end{cases} \tag{4.2}$$

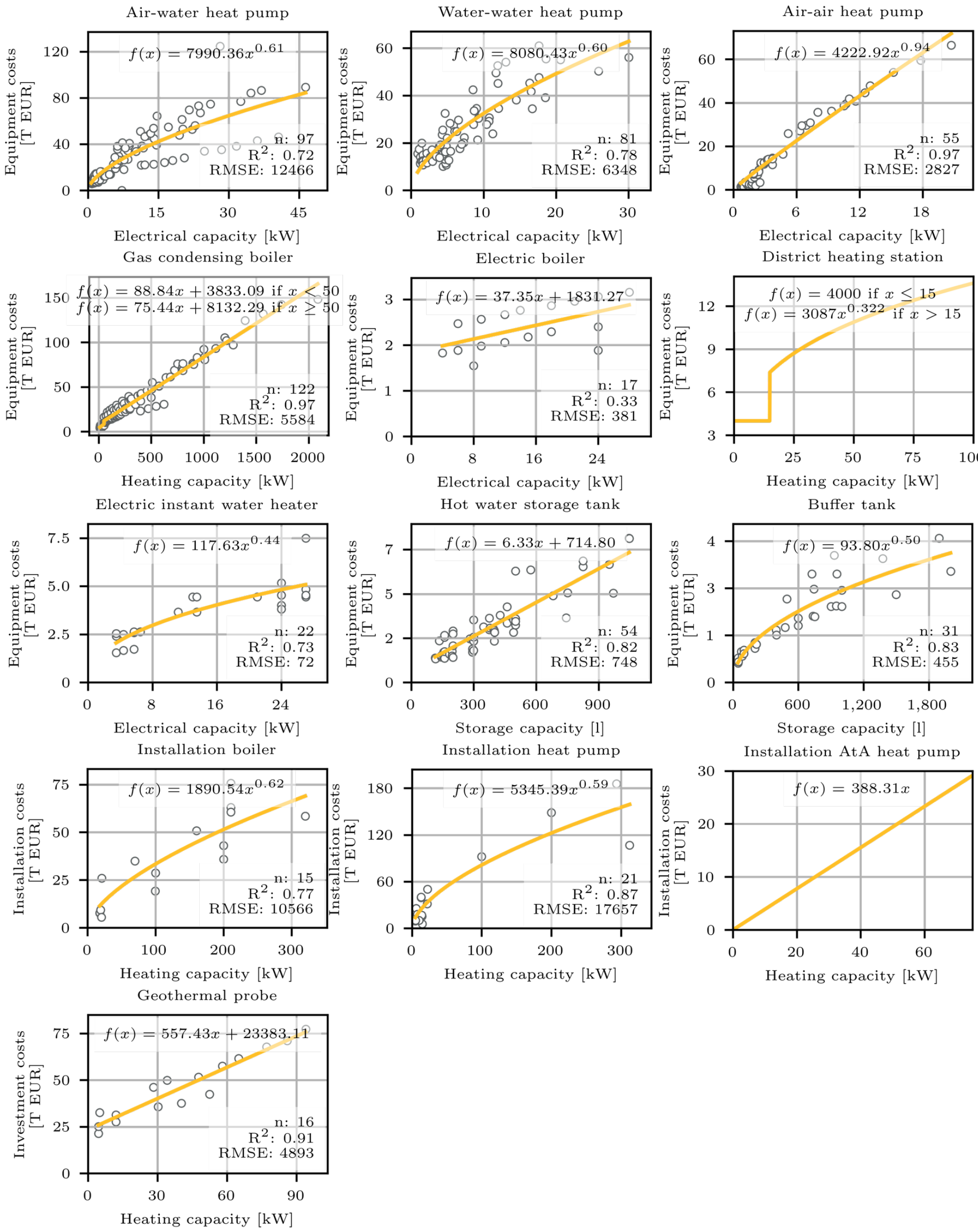


Figure 4.1.: Equipment and installation cost functions. Data-based functions show the number of data points n and the R^2 and RMSE of the function.

For heat pump systems, we consider the dependency of the seasonal performance factor SPF_3 on the nominal supply temperature. In the context of this paper, we understand the nominal supply temperature as the minimal necessary supply temperature to enable sufficient heat transfer from the radiators into the room to cover a building's heat load. The heating system's supply temperature depends on the radiators' heat exchange area and the building's energy efficiency.

The higher the area of the radiators, the lower the supply temperature required to transport the same amount of heat into the room (see Figure 4.2 for typical temperature ranges of different radiator types). The better a building is insulated, the more its heat demand and the supply temperature decrease (for the same area of the radiators).

The SPF_3 measures a heat pump's efficiency over an entire year, dividing the annual heat supply by the annual power consumption of the heat pump. It depends on the temporally varying heat source and sink temperatures and heat demands throughout the year. The lower the temperature difference between the heat sink and heat source, the higher the COP. The heat sink represents the supply temperature of the heating system. The heat source is the ambient air temperature in the case of air-source heat pumps and the groundwater temperature in the case of water-source heat pumps. We estimate SPF_3 for AtW and WtW heat pumps according to the Lämmle et al. (2022) and the SPF_3 of AtA heat pumps based on Eguiarte et al. (2020), EWI (2025). A detailed explanation of the assumptions can be found in C.8.

Figure 4.2 shows the seasonal performance factor SPF_3 of different heat pumps and heating systems. For decentralized heat pumps, the SPF_3 increases linearly with decreasing supply temperature within the considered temperature range. Decentralized WtW heat pumps reach the highest annual COPs as the groundwater has a higher temperature than the ambient air during the heating period. For centralized heat pumps, the SPF_3 is lower than that of decentralized heat pumps at the same supply temperature. This is because the heat sink of the centralized heat pump is the heating grid, whose supply temperature we assume to be 10 K above the supply temperature of the building's heating system. A temperature difference of 10 K is necessary to enable efficient heat exchange between the heating grid and the hydraulically separated heating systems inside the buildings and to compensate for heat losses. We assume that domestic hot water must be heated to 55°C for hygienic reasons. If the heating grid temperature is too low to heat hot water to 55°C, hot water heating is complemented with decentralized electric heaters with an assumed energy efficiency of 1. This reduces the slope of the SPF_3 of centralized heat pumps for supply temperatures below 55°C.

4.2.5. Energy prices

We calculate the LCOH across a range of hydrogen, SNG, and electricity prices because future energy prices are uncertain. The future price of green hydrogen is uncertain due to potential learning-induced declines in production costs and uncertainty regarding transport costs and the structure of the hydrogen market that has yet to emerge. Not least, the hydrogen demand for heating may influence the price of hydrogen. To capture all this uncertainty, we consider a range of possible future hydrogen prices between 50 and 250 EUR/MWh. The upper limit is set by the pessimistic estimate that hydrogen prices will not decrease from

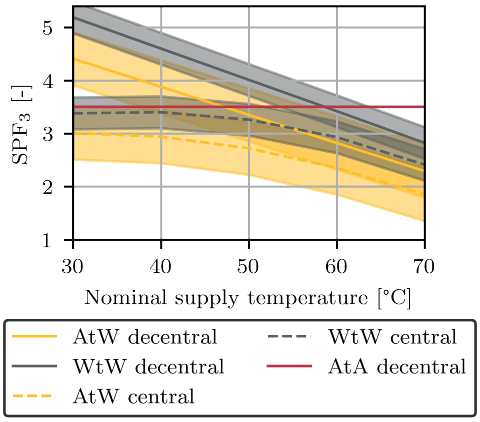


Figure 4.2.: Relationship between the heat pump's seasonal performance factor SPF_3 and the heating system's nominal supply temperature. Areas reflect ranges in the underlying data.

today's hydrogen production costs. Data for today's hydrogen production costs vary greatly, for instance, BGC (2023) lists costs in the range of 200 EUR/MWh and 315 EUR/MWh. We use the costs of 250 EUR/MWh from EEX (2023) as a moderate estimate for today's prices. The lower limit is set by the lower end of price projections for 2050 at around 50 EUR/MWh (Merten and Scholz, 2023, Moritz et al., 2023).

SNG is produced from green hydrogen by catalytic methanation, which requires CO_2 capture via direct air capture. Thus, we assume that the SNG price is linked to the hydrogen price. Due to the additional process step of methanation, the production costs of SNG are higher than those of green hydrogen. Contrarily, the transport costs are higher for hydrogen than for SNG due to hydrogen's lower volumetric energy density. We use import costs to calculate the price ratio between SNG and hydrogen. For both fuels, we calculate the average costs of imports to Germany of the 15 origin countries with the lowest import costs for a wide range of production and transport cost scenarios (EWI, 2024b, Moritz et al., 2023). In addition to the import costs, we include a markup for storage costs (see C.6). The results are displayed in Figure 4.4. It reveals that the SNG-hydrogen price ratio lies between 1.1 and 3.1, meaning that SNG is 1.1 to 3.1 times as expensive as hydrogen. The SNG-hydrogen price ratio is varied in a sensitivity analysis within these boundaries and set to 1.9 in the baseline scenario, which is the average ratio in the data.

Future electricity prices are inherently uncertain, shaped by demand, the generation mix, and fuel costs. As a baseline, we adopt the mean electricity price (65 EUR/MWh) from recent energy system studies (Figure 4.3, y-axis). While real-world electricity prices fluctuate hourly, and the effective cost for heat pumps depends on their consumption profile and flexibility (Ruhnau et al., 2020), we use base prices due to the lack of studies reporting heat-pump-weighted electricity prices in future net-zero energy systems.

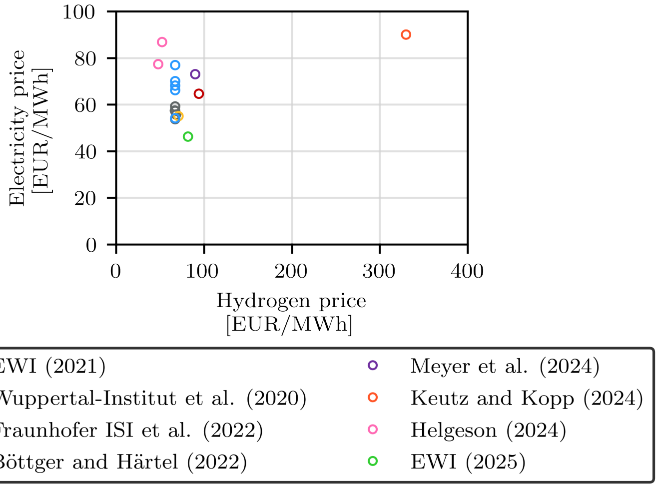


Figure 4.3.: Hydrogen and electricity prices in climate neutral energy system scenarios for Germany.

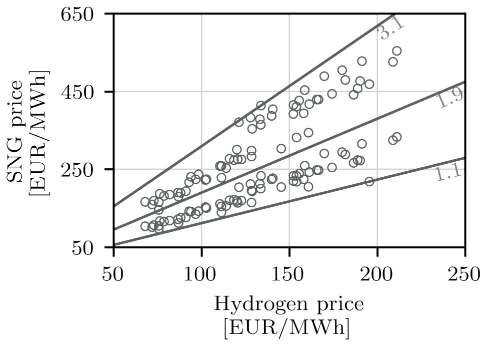


Figure 4.4.: Hydrogen and SNG costs based on EWI (2024b), Moritz et al. (2023) and the resulting price ratios

Electricity prices will also be influenced by hydrogen prices, a critical factor in heating costs and a key variable in this analysis. The relationship is bidirectional: electricity is converted to hydrogen via electrolysis, while hydrogen powers backup generation. However, Figure 4.3 depicts the hydrogen price corresponding to each electricity price (x-axis) and shows that this linkage is not straightforward. To capture the uncertainty in electricity prices driven by hydrogen prices and other factors, we conduct a sensitivity analysis, varying electricity prices between 35 and 95 EUR/MWh, reflecting the range in the referenced studies.

4.2.6. Settlement types

We investigate rural, village, urban, and city settlements in order to understand the influence of the settlement type on the levelized cost of heating. We refer to the 13 settlement types introduced by AGFW (2001) and select four types representing a wide range of settlements for the following analysis (types 1, 2, 7b, and 8). The rural settlement represents a scattered settlement consisting of detached buildings with larger plots of land, such as those found in small village settlements or on the outskirts of cities. The village settlement represents residential areas with detached and semi-detached houses, like larger villages or suburban communities with single- and multi-family dwellings. The primary purpose of rural and village settlements is residential. The urban settlement represents block development, a typical urban building form consisting of large multi-family houses. The typical use of the block development is predominantly residential. The city settlement represents the city buildings in the centers of large cities. Similar to urban settlements, the houses in city settlements are arranged in blocks. The buildings tend to be fewer but larger. Typical uses of city buildings are more commercial and less residential.

Table 4.3.: Settlement type characteristics

Settlement type		Rural	Village	Urban	City
Number of buildings	[-]	100	100	19	19
Heated area per building	[m^2]	130	130	680	680
Heated area per household	[m^2]	130	130	92	92
Heat load decentralized	[kW]	6.5	6.5	34	75
Heat load centralized	[kW]	650	650	646	650
Simultaneity factor	[-]	0.78	0.74	0.68	0.6
Heat distribution loss	[%]	43[a]	18	8	4
Heat density	$[\frac{\text{MWh}}{\text{ha·yr}}]$	51	280	738	1345
Gas density	$[\frac{\text{MWh}}{\text{ha·yr}}]$	54	295	777	1416
Electricity density[b]	$[\frac{\text{MWh}}{\text{ha·yr}}]$	33	180	475	865
Heat distribution costs	$[\frac{\text{ct}}{\text{kWh}}]$	11.26[c]	3.51	1.80	1.20
Gas grid fees[d]	$[\frac{\text{ct}}{\text{kWh}}]$	3.34/2.83	1.98/1.68	1.47/1.25	1.22/1.04
Hydrogen grid fees[d]	$[\frac{\text{ct}}{\text{kWh}}]$	6.26/5.17	3.72/3.07	2.76/2.28	2.3/1.9
Electricity grid fees[d]	$[\frac{\text{ct}}{\text{kWh}}]$	29.29/26.62	18.59/16.9	14.33/13.03	12.21/11.09

[a]extrapolated, see Figure C.3 in the appendix, [b]the electricity density was approximated based on the heating density given in AGFW (2001) and the historical ratio between energy demands for electricity and heat in 2021 given in AGEB (2022), [c]extrapolated, see Figure 4.5, [d]decentralized heating / centralized heating

To enable a comparison between centralized and decentralized heating, we analyze standardized districts with a total heat load of 650 kW, corresponding to 100 buildings in a rural or village settlement. This heat load can be represented without over-extrapolating our investment cost functions. The heat load of the urban and city settlement is scaled accordingly and is rounded to whole houses, given the heated area per building. Table 4.3 shows the characteristics of the four representative settlement types.

4.2.7. Grid fees and costs

Our calculation of future heating costs includes infrastructure costs. Current infrastructure costs exhibit substantial heterogeneity across Germany, some of which can be explained by local heating densities. Additionally, future infrastructure costs are uncertain because they depend on required grid expansion. Residential heating choices themselves may drive part of these expansion costs, but the costs of some infrastructures, e.g., the electricity grid, are influenced by energy system developments that go beyond heating. Here, we use future grid fees to approximate average infrastructure costs within the LCOH approach. We do so because current regulation implies that infrastructure costs are distributed to end customers via grid fees. Note that, however, grid fees do not generally reflect marginal grid costs associated with heating technologies (c.f. Hanny et al., 2022).

We employ a two-step approach to derive a baseline assumption for per-kWh grid fees for different settlement types and centralized (district heating) and decentralized (in-building heat generation) distribution cases. First, we use historical data to estimate a functional relationship between infrastructure costs and heating density, which allows for differentiation of grid fees by settlement type. Second, we scale the previously derived cost functions to future levels. To approximate future cost levels, we use estimates of future grid fees for 2045. The estimates of future grid fees are taken from studies that assume that most heating systems use the corresponding infrastructure and consider the corresponding need for infrastructure expansion (e.g., electricity grid fees are estimated for a scenario with a high share of heat pumps and hydrogen grid fees with a high share of hydrogen boilers). Specifically, we scale the derived cost functions to estimates of future grid fees for households and commercial customers for energy carriers delivered to decentralized and centralized heating systems, respectively. We then use the scaled cost functions to derive point estimates for future grid fees in the different settlement types. The cost functions and resulting assumptions for our baseline scenario are presented in Figure 4.5. Note that we vary grid fees in a sensitivity analysis to reflect heterogeneity within settlement types and additional uncertainties. For simplicity, our per-kWh approach neglects that grid fees have fixed and sometimes power-based components in addition to per-kWh components.

Looking at electricity infrastructure cost specifically, historical data on local distribution grid costs and corresponding heating densities are derived from Bundesnetzagentur (2023b). Future electricity grid fees are uncertain and depend on the diffusion and allocation of renewable energy capacity and demand, such as heat pumps. German grid operators (50Hertz Transmission GmbH et al., 2023) and energy system studies such as ef.Ruhr and EWI (2024), Fraunhofer

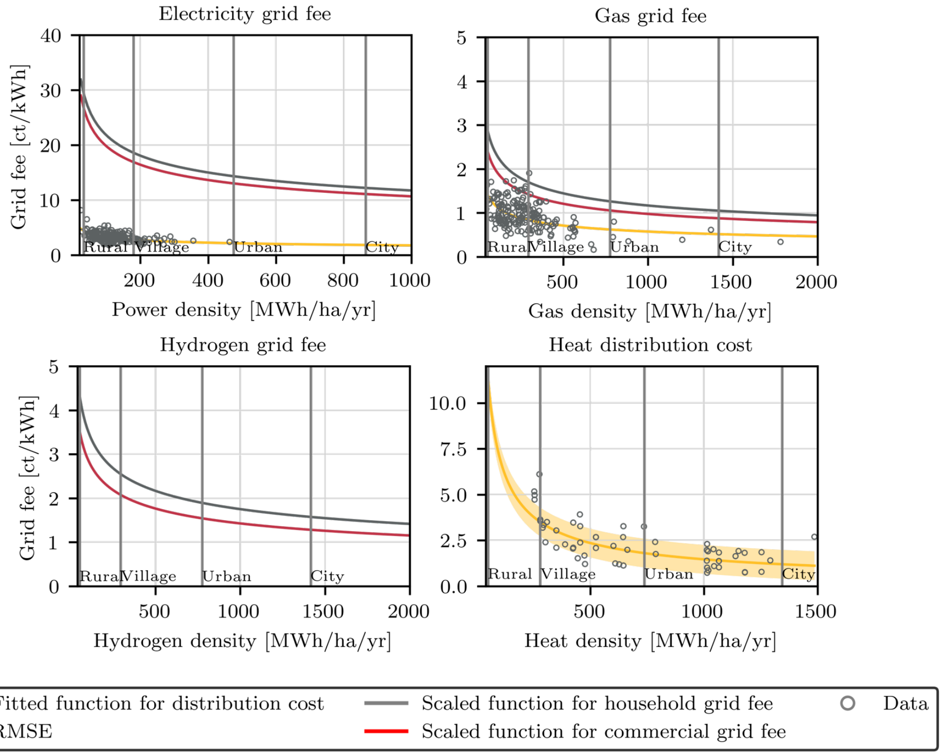


Figure 4.5.: Reference infrastructure costs for electricity, gas, hydrogen, and heating grids depending on the energy density. The data on electricity grid fees contains an additional data point at a power density of 3,455 MWh/ha/yr.

ISI et al. (2024), Agora Energiewende (2024) and Bauermann et al. (2024) expect significant investment needs due to the further deployment of renewables and increasing demand peaks related to heat pumps and electric vehicles. On the other hand, increasing demand could lead to lower grid fees as costs are distributed across a larger base.

For this paper, we estimate future electricity grid fee levels based on projected investment costs and electricity demand from the studies referenced above. Capital costs are derived assuming a weighted average cost of capital (WACC) of 5.5 % and an economic lifetime of 40 years. To approximate full grid costs, we apply a fixed investment-to-operational cost ratio of 1:2 (analogous to ef.Ruhr and EWI (2024)). Per-kWh grid fees are calculated by distributing total grid costs across projected electricity demand in each study. Given that not all sectors contribute equally to grid fees, we account for sectoral exemptions, particularly for certain industrial consumers, and ensure that cost allocation aligns with current voltage-level-based contributions. To do so, sectoral cost-sharing proportions are held constant at today's levels.

The resulting future grid fee levels, which are listed in Table 4.4 alongside electricity demands and infrastructure costs, range from 16.35 ct/kWh to 27.35 ct/kWh

Table 4.4.: Approximation of future grid fees based on 2045 demand and grid investment cost data in existing studies

Study	Grid fees decentralized [ct/kWh]	Grid fees centralized [ct/kWh]	Gross electricity demand [TWh]	Grid investment costs [Billion EUR]
ef.Ruhr and EWI (2024)	20-35	14-29	1128	732
Agora Energiewende (2024)	18	16	1267	514
Fraunhofer ISI et al. (2024)	26-27	23	1191-1276	656-681
Bauermann et al. (2024)	27-28	18–22	1080-1300	651

for households (compared to 9.35 ct/kWh today) and 16.42 ct/kWh to 23.42 ct/kWh for businesses (compared to 7.42 ct/kWh today). For the baseline scenario, we adopt the midpoint of projected increases, yielding 21.85 ct/kWh for household customers and 19.92 ct/kWh for business customers. To capture uncertainty, we apply a ±30 % variation around the midpoint, covering the full range of grid fee level estimates, historical variance of grid costs within each settlement type, and additional uncertainty.

In the case of gas grids, SNG can be transported without modifications through the existing grid. We take historical data on gas distribution costs and energy density Bundesnetzagentur (2023a) to fit the cost functions, which are depicted in Figure 4.5. The functions are scaled to match future gas grid fees estimated for a 95 % emission reduction scenario with a large share of SNG in residential heating (c.f. EWI), 2018). This study finds an increase of the gas grid fees by 20 % for households and 30 % for businesses by 2050 compared to 1.7 and 1.3 ct/kWh, respectively, in 2023.

For the case of hydrogen infrastructure costs, we assume that the variance across and within settlement types is similar to existing gas infrastructure. Thus, we apply the same functional form as for SNG. In terms of the cost level, i.e., the scaling of the cost function, hydrogen grid costs are more uncertain than those of SNG. It is unclear how demand and supply will develop, and a widespread hydrogen grid infrastructure does not exist today. Projections range from 4.2 ct/kWh in 2045 (EWI, 2021) on transport level only, to 4.1-4.6 ct/kWh for transport and distribution in 2030 (Cerniauskas et al., 2020) or 2 ct/kWh for transport and distribution in 2050 (Wuppertal-Institut et al., 2020). Note that Cerniauskas et al. (2020) and Wuppertal-Institut et al. (2020) do not consider decentralized hydrogen heating. The large range can be explained by the different time horizons and underlying demand scenarios. For this article, we derive a baseline assumption from EWI (2024a), a study on potential future hydrogen grid fees in a scenario with widespread hydrogen use in residential heating. On average over all scenarios, hydrogen grid fees in 2045 are about 80 % higher for households and 90 % higher for businesses than 2023 natural gas grid fees, which were 1.7 and 1.3 ct/kWh, respectively. Due to the high uncertainty related to hydrogen grid costs and the heterogeneity in the data on today's gas distribution costs, we vary hydrogen grid fees between -30% and +30% in our sensitivity analysis. This includes the scenario range from EWI (2024a) and the variance present in the historical data.

In the case of heating grids, we parameterize grid costs using data on costs for newly built heat distribution grids depending on the heat density. We opt for using this approach instead of a combination of historical distribution costs and estimated future grid fees for existing grids, because we would like to provide insights into the expansion rather than the continuation of heating grids. Figure 4.5 shows the data and function taken from Erdmann and Dittmar (2010). We conduct sensitivity analyses within a range of -40% to +40% for heat distribution costs to address the variance present in the data. The full parametrization for all cost functions estimated for infrastructure costs can be found in C.7.

4.3. Results and discussion

This section examines the impact of uncertainties and heterogeneities on the levelized cost of heating. We successively focus on uncertainty in the hydrogen price (subsection 4.3.1), uncertainty in other input parameters (subsection 4.3.2), and heterogeneity in supply temperatures (subsection 4.3.3). Finally, we discuss the limitations of our study (subsection 4.3.4).

4.3.1. Uncertainty of the hydrogen price

Of the many relevant uncertainties, we first focus on the uncertainty of future energy prices. We investigate this uncertainty by varying the hydrogen price across a range between 50 EUR/MWh (the lowest 2050 cost estimate in Moritz et al. (2023)) and 250 EUR/MWh (today's cost as according to EEX (2023)). The price of SNG is assumed to vary with the hydrogen price according to a fixed ratio of 1.9, the average over various supply options and cost scenarios in Moritz et al. (2023). Like hydrogen prices, future electricity prices are uncertain. Initially, we assume an electricity price of 65 EUR/MWh. To account for uncertainty, the electricity price is varied from 35 EUR/MWh to 95 EUR/MWh in a subsequent analysis. This range reflects the range from projections for net-zero emission scenarios for 2045 in various energy system studies (Böttger and Härtel, 2022, EWI, 2021, 2025, Fraunhofer ISI et al., 2021, Helgeson, 2024, Keutz and Kopp, 2024, Meyer et al., 2024, Wuppertal-Institut et al., 2020). Additionally, we vary other relevant uncertain parameters, namely electricity, hydrogen, and SNG grid fees, as well as heating grid and heat pump equipment costs. All parameter assumptions are described in detail in the Methods and data section.

Figure 4.6 displays the results on LCOH as a function of hydrogen prices by settlement type to capture heterogeneity in heat demand density. The most salient observation is that the costs decrease from rural to city settlements, which can be explained by higher energy densities reducing grid fees, heat distribution costs, and heat distribution losses.

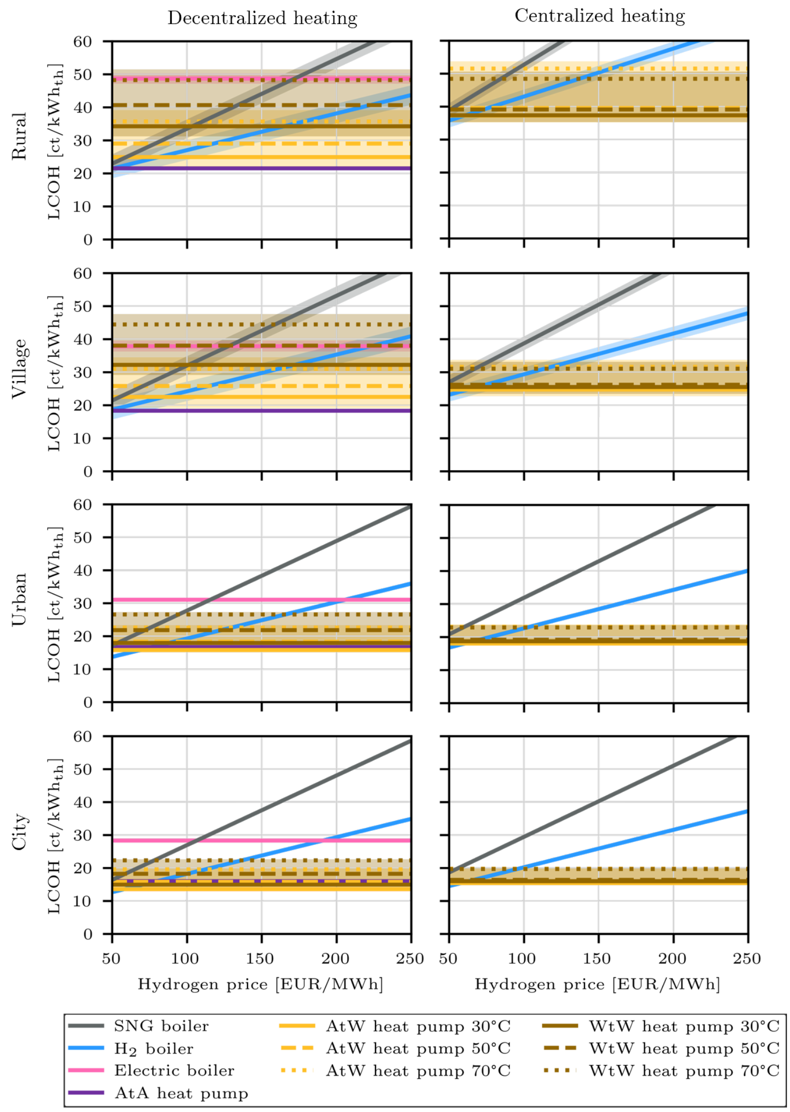


Figure 4.6.: Levelized costs of heating for decentralized heating depending on the hydrogen price and supply temperature of the heating system. The lines reflect average investment costs, and the areas reflect uncertainty in investment costs.

Focusing on decentralized heating options (left column in Figure 4.6), AtA heat pumps are often the cheapest option, especially in rural and village settlements. AtW and WtW heat pumps tend to be more expensive, implying that their higher investment costs cannot be compensated by their higher seasonal performance factor. Only in cities and urban settlements with low supply temperatures have AtW and WtW heat pumps LCOH close to AtA heat pumps because of the larger average installed capacity per building and related scale effects. WtW heat pumps are particularly expensive in rural and village settlements as the geothermal probe has a high proportion of the costs (see Figure C.1). The LCOH of AtW and WtW converge in urban and city settlements due to larger building sizes. In the following analysis, we refer to the cheapest option among AtW and WtW heat pumps as "decentralized heat pumps". In contrast to hydrogen and SNG boilers, the heat pumps' LCOH is unaffected by rising hydrogen prices because we assume electricity and hydrogen prices to be uncorrelated. Among the other technologies, hydrogen boilers are the cheapest. At low hydrogen prices, SNG boilers have low LCOH too, but diverge with increasing hydrogen prices, as high SNG prices become more important than the slightly lower SNG grid fees boiler costs. Electric boilers suffer from relatively high electricity grid fees and prices more than they benefit from low investment costs.

Turning toward centralized heating (right column in Figure 4.6), heat pumps are the cost-efficient technology for almost all considered hydrogen prices. Large centralized heat pumps benefit most from scale effects compared to decentralized heating. Scale effects also mitigate the cost difference between AtW and WtW heat pumps, which is why we refer to both as "centralized heat pumps" in the following. Furthermore, the LCOH of centralized heat pumps for supply temperatures of 50°C or below converge because lower supply temperatures do not further reduce the effective seasonal performance factor due to the required complementary direct electric hot water heating (see Figure 4.2). Boiler technologies have a higher LCOH than heat pumps due to higher energy costs and smaller scale effects. Only for very low hydrogen prices do boilers and heat pumps achieve a similarly low LCOH. Put differently, centralized heating is particularly attractive for heat pumps as significant scale effects outweigh heat distribution costs and heat losses.

Across decentralized and centralized heating options, AtA heat pumps are among the cheapest options in all settlements. However, heating with AtA heat pumps may be perceived as less comfortable (c.f. Karmann et al., 2017), and AtA heat pumps may also be used for cooling, which is not accounted for in our LCOH comparison. For this reason, we exclude AtA heat pumps from the following analysis. Among the remaining technologies, hydrogen boilers, centralized heat pumps, and decentralized AtW heat pumps are the cheapest options, depending on the settlement type, hydrogen price, and supply temperature. Across settlements, decentralized hydrogen boilers are cost-efficient for lower and heat pumps for medium to high hydrogen prices. In rural settlements, decentralized heat pumps are cost-efficient. In the other settlement types, decentralized or centralized heat pumps can be cheaper, depending on the supply temperature.

4.3.2. Uncertainty in other relevant input parameters

This section analyzes the effect of changes in the previously fixed electricity price, SNG-hydrogen price ratio, grid fees, heating grid costs, and heat pump equipment costs on the cost-efficient heating technology. For these analyses, we consider settlements with heterogeneous supply temperatures. Decentralized options are designed for building-specific supply temperatures, while centralized solutions must cater to the highest supply temperature in the settlement. More precisely, we assume an average supply temperature of 50°C, the average supply temperatures in the current German building stock (Umweltbundesamt, 2023), and a highest supply temperature of 70°C. Below, we conduct sensitivity analyses for settlements with homogeneous supply temperatures.

Figure 4.7 shows the cost-efficient technology and the relative LCOH difference between the best and second-best technology for various hydrogen prices and in different settlement types. Each column in the figure represents one settlement type, and each row displays the effect of changing one input parameter.

Overall, we observe that decentralized hydrogen boilers and centralized and decentralized heat pumps are the cheapest technologies for most of the considered parameter variations. In rural settlements (left column), hydrogen boilers or decentralized heat pumps can be cost-efficient, depending on the hydrogen price. In villages, urban settlements, and cities (the other columns), centralized and decentralized heat pumps are most often cost-efficient and almost in cost-parity. Hydrogen boilers become competitive at lower hydrogen prices, and heat pumps do so for some parameter variations when hydrogen prices are higher. The threshold hydrogen price between hydrogen boilers and heat pumps is around 120 EUR/MWh in rural settlements and decreases to around 80 EUR/MWh in cities. SNG boilers are cost-efficient only if the hydrogen price and the SNG-hydrogen price ratio are at the lower boundary of the investigated parameter ranges.

Varying electricity and SNG prices

The first row of Figure 4.7 analyzes the impact of changing the electricity price between 35 and 95 EUR/MWh (our baseline assumption was 65 EUR/MWh). This variation reflects uncertainty about future base electricity prices, which are driven by aspects such as the availability of renewable electricity and changes in the electricity demand for other applications. Furthermore, the heat pump load patterns are uncertain, affecting the effective heat pump load price relative to the base price (Ruhnau et al., 2020). At low hydrogen prices, a high electricity price amplifies the economic viability of hydrogen boilers compared to heat pumps. This effect becomes less pronounced with increasing heat densities due to decreasing heat losses. At high hydrogen prices, a high electricity price favors decentralized heat pumps compared to centralized ones. This is because the higher seasonal performance factor and the absence of heat losses increase the economic attractiveness of decentralized heat pumps.

The second row of Figure 4.7 investigates the effect of SNG-hydrogen price ratio variations between 1.1 and 3.1 (our baseline assumption was 1.9). This

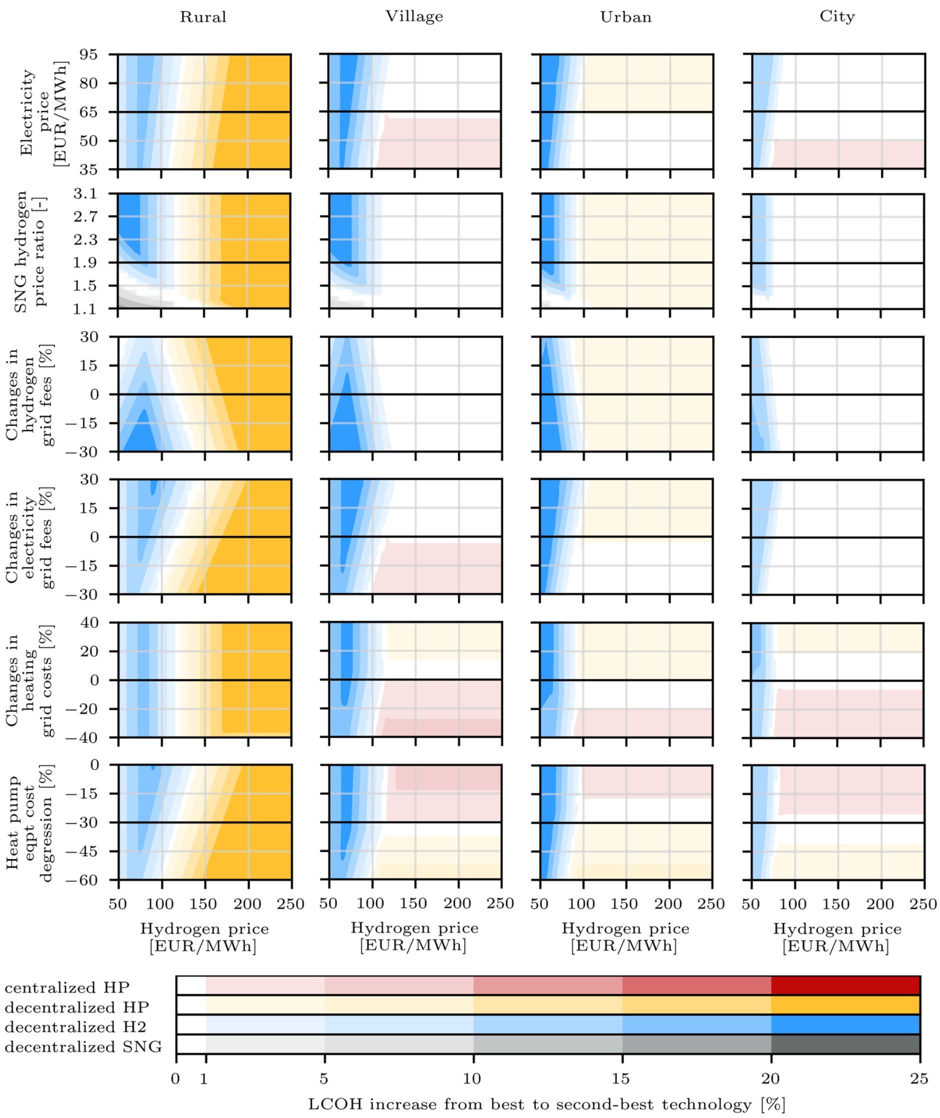


Figure 4.7.: The impact of uncertain and heterogeneous parameters on the cost-efficient heating technology in different settlement types and buildings with heterogeneous supply temperatures. The maximum supply temperature is 70°C, the average supply temperature is 50°C. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.

price ratio is subject to uncertainty due to uncertain future cost degression of electrolyzers, methanation, and a climate-neutral CO_2 source, as well as uncertainty regarding the origin countries of imported fuels. The results show that SNG is hardly cost-efficient in the considered parameter range. If hydrogen is as cheap as 50 EUR/MWh, SNG can compete with hydrogen boilers in rural settlements if the SNG price does not exceed 1.6 times the hydrogen price. For higher hydrogen prices and in more urban settlements, the SNG-hydrogen cost ratio must be even lower to make SNG competitive.

Varying grid fees and grid costs

The third row of Figure 4.7 analyzes uncertainty and heterogeneity in hydrogen grid fees. Our baseline assumption for this parameter stems from a future scenario that assumes a relatively high share of hydrogen boilers (EWI, 2024a). We consider a ± 30 % variation relative to this baseline to reflect heterogeneity within the considered settlement types and cost uncertainty. The uncertainty is related to limited experience with hydrogen grids and to the hydrogen demand to which grid costs will be distributed. As expected, we observe that increasing hydrogen grid fees reduce the competitiveness of hydrogen boilers relative to other options. For the example of villages, a 30 % increase in hydrogen grid fees implies that hydrogen boilers would only be cost-efficient at hydrogen prices below 100 EUR/MWh. Similar trends can be observed for the other settlement types, with hydrogen still playing a somewhat larger role in rural settlements and a smaller role in urban settlements and cities.

The fourth row of Figure 4.7 examines the effect of varying electricity grid fees. Our baseline assumption of 21.85 ct/kWh represents the average of expected electricity grid fees in 2045, which we derive from several recent studies on grid expansion costs (Agora Energiewende, 2024, Bauermann et al., 2024, ef.Ruhr and EWI, 2024, Fraunhofer ISI et al., 2024). In contrast to the hydrogen grid fees, uncertainty in electricity grid fees is driven not only by future heat demand but also by the diffusion of electric vehicles and renewable generators. Additionally, electricity grid fees can vary within settlements (Bundesnetzagentur, 2023b). We reflect uncertainty and within settlement heterogeneity by a variation of -30 % and +30 % from the baseline. This variation corresponds to the rounded cost range in the studies and includes heterogeneity within the settlements. As expected, we see that higher electricity grid fees favor the economic viability of hydrogen boilers over heat pumps. Furthermore, higher electricity grid fees favor decentralized heat pumps over centralized ones. The competitiveness of the different technologies is more sensitive toward a change in electricity grid fees in rural and village settlements than in urban settlements due to higher baseline grid fees. Overall, increased electricity fees lead to similar effects as higher electricity prices. Among the infrastructure cost sensitivities, electricity grid fees have the highest impact on the cost-efficiency of heat pumps and hydrogen boilers.

The fifth row of Figure 4.7 investigates the sensitivity of our results to changes in the heating grid costs. The analysis confirms the intuition that higher heating grid costs promote decentralized technologies, namely hydrogen boilers at low hydrogen prices and decentralized AtW heat pumps at high hydrogen prices. Across settlements, the viability of centralized heat pumps is similarly sensitive toward a change in heating grid costs in villages, urban settlements, and cities. If heating grid costs decrease by 40 %, decentralized heat pumps are cost-efficient in all three settlement types for most considered hydrogen prices, albeit with a cost advantage of less than 10 % compared to decentralized heat pumps. In rural settlements, heating grids remain uneconomical even if heating costs decrease by 40 % due to significantly higher heat distribution costs and heat losses.

Varying heat pump equipment costs

The sixth row of Figure 4.7 analyzes the effect of uncertain heat pump equipment costs. In our baseline scenario, we assume that equipment costs decrease by 30 % from today due to learning. We consider a cost reduction between 0 % and 60 % as uncertainty regarding future learning. In rural settlements, decentralized heat pumps intuitively become more competitive relative to hydrogen boilers as heat equipment costs decrease. In the other settlements, the relative cost efficiency of heat pumps compared to hydrogen boilers changes only slightly. Furthermore, we find that equipment cost reductions favor decentralized heat pumps. This is because the share of heat pump equipment costs in the total system costs is larger for decentralized than for centralized heat pumps.

4.3.3. Heterogeneity in the supply temperatures

The previous sensitivity analyses examined settlements with heterogeneous supply temperatures representing today's distribution with an average of 50°C (relevant for decentralized heating) and a maximum of 70°C (relevant for centralized heating). This section looks at settlements with homogeneous supply temperatures.

Figure 4.8 shows the sensitivity analysis for a supply temperature of 30°C, representing a newly developed area with high building energy efficiency. Decreasing the supply temperature improves the economics of both decentralized and centralized heat pumps, but the advantage is larger for decentralized ones. This is because the difference in the seasonal performance factor between decentralized and centralized heat pumps increases at lower supply temperatures (see Figure 4.2). As a result, heat pumps become cost-efficient at lower hydrogen prices than in the previous analysis. The threshold hydrogen price between hydrogen boilers and heat pumps is around 80 EUR/MWh in rural settlements and decreases to around 60 EUR/MWh in cities. In rural settlements, decentralized heat pumps have a clear cost advantage of more than 25 % for higher hydrogen prices. In the other settlement types, the cost advantage over centralized heat pumps is mostly less than 15 %. The opposite effect occurs if we assume supply temperatures of 70°C, e.g., in a settlement with homogeneously low building-specific energy standards (see Figure C.4 in the Appendix). In this case, centralized heat pumps are favored over decentralized ones. However, cen-

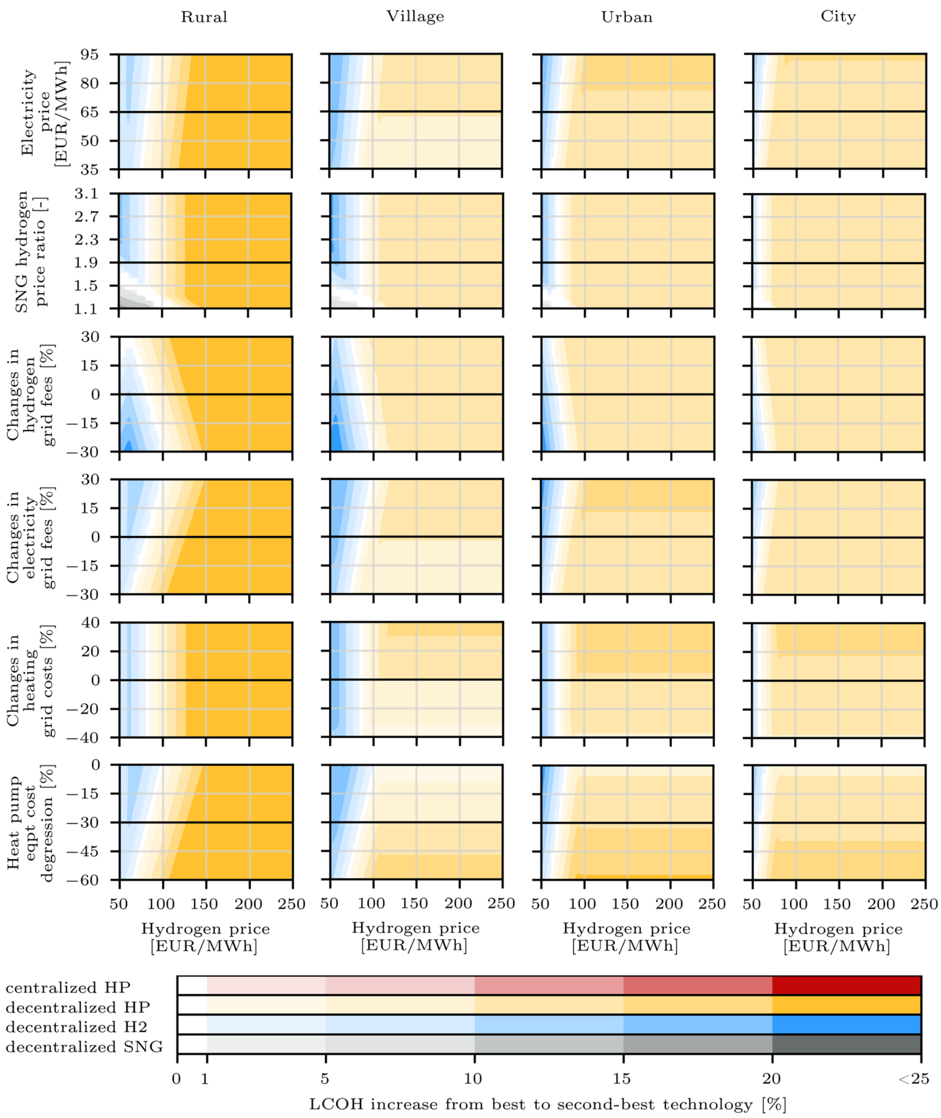


Figure 4.8.: The impact of uncertain and heterogeneous parameters on the cost-efficient heating technology in different settlement types and buildings with a supply temperature of 30° C. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.

tralized and decentralized heat pumps remain almost in cost parity. Also, the threshold hydrogen price between hydrogen boilers and heat pumps shifts to the right and is around 180 EUR/MWh in rural settlements and decreases to around 110 EUR/MWh in cities. Note that, in the future, settlements with lower supply temperatures are likely to occur more often as energetic refurbishment of the existing building stock progresses.

4.3.4. Limitations

When interpreting these results, some limitations should be kept in mind. First, while our analysis aims to be comprehensive on uncertainties and heterogeneities that affect the future cost-efficiency of heating technologies, we do not investigate possible transition pathways to reach this future. Potential capital or labor shortages in the context of the system-wide transition may reduce the relative attractiveness of heating options with a high implementation effort compared to our analysis, e.g., building new infrastructure. Second, we do not consider hybrid heating systems. Especially centralized heat pumps could be combined with hydrogen-fired combined heat and power plants or industrial waste heat (c.f. EWI, 2021), which would make heating grids more attractive than our analysis suggests. Similarly, decentralized heat pumps could be combined with existing gas boilers, which could operate as backup based on SNG or biogas. This could reduce peak power demand, heat pump equipment cost, and electricity grid expansion (c.f. Billerbeck et al., 2024, EWI, 2025, Rosenow, 2022).

Additionally, we neglect biomass and solar thermal, which could complement both centralized and decentralized technologies, albeit with a limited overall potential. Third, to be consistent with our exogenous assumptions on grid fees, we only investigate uniform investment decisions, meaning that all buildings in one area use the same heating option. In settlements with heterogeneous buildings, the individual building optimum can differ from the collective optimum. For instance, if the optimal uniform decision is to use centralized heat pumps, buildings with low supply temperatures may be incentivized to switch to decentralized heat pumps, increasing the heating grid costs for the remaining consumers. Relative to our results, this may increase the attractiveness of decentralized heat pumps, which use non-heating-exclusive infrastructure, over centralized heat pumps and hydrogen boilers, which use heating-exclusive infrastructure.

4.4. Conclusion and policy implications

This article investigates which heating technologies are cost-efficient in a future climate-neutral energy system, given uncertainties in energy, technology, and infrastructure costs and heterogeneity in settlement types and buildings. To that end, we calculate the future levelized costs of heating technology options for a set of exemplary buildings and settlement types in Germany and conduct extensive sensitivity analyses. Across the wide range of heterogeneity and uncertainty that we consider, we find that AtA heat pumps are the most cost-efficient technology. While AtA heat pumps may provide additional cooling benefits, their heat may be perceived as less comfortable. If we exclude AtA heat pumps from our technology set, decentralized hydrogen boilers, centralized heat pumps, and decentralized AtW and WtW heat pumps are the most cost-efficient technologies. The relative future competitiveness of these three heating options strongly depends on the settlement type, future hydrogen and electricity prices, infrastructure costs and related grid fees, and potentially decreasing heat pump costs.

Intuitively, hydrogen boilers become less competitive with increasing hydrogen prices, hydrogen grid fees, and heat densities. While hydrogen boilers may be competitive in rural settlements for more parameter combinations, they appear uneconomical in cities across the considered scenarios. Among the heat pump technologies, we find decentralized and centralized heat pumps to be similarly cost-efficient over a wide range of input assumptions. Decentralized heat pumps benefit from higher seasonal performance factors, while centralized heat pumps benefit from significant scale effects on heat pump investment costs. In rural settlements, decentralized heat pumps have a larger cost advantage over centralized ones due to high heating grid costs and heat losses. High electricity prices and grid fees improve the competitiveness of hydrogen boilers, particularly in rural areas, and favor decentralized heat pumps over centralized ones. In settlements with heterogeneous supply temperatures or a homogeneous supply temperature of 70°C, decentralized and centralized heat pumps are almost in cost parity. In settlements with a homogeneous supply temperature of 30°C, decentralized heat pumps have a cost advantage over centralized ones.

Our results allow us to draw three main conclusions for policy- and decision-makers in the German context. First, SNG does not seem economical in the long term, even though it could utilize existing infrastructure in the short term. For most of the investigated combinations of input parameters, either hydrogen or heat pumps are cheaper than SNG. Second, there seems to be a limited scope for decentralized hydrogen boilers. According to our results, hydrogen may be economical only at low hydrogen prices in rural settlements. Settlements with higher heat densities preferably use heat pumps unless hydrogen prices are very low. High hydrogen prices and uncertain hydrogen grid fees can deteriorate the competitiveness of hydrogen boilers. In this context, a negative feedback loop may emerge in the expectedly small hydrogen market, as potential hydrogen demand for heating may increase hydrogen prices. Given the high uncertainty in the hydrogen price and grid fees, hydrogen boilers also seem to be a riskier option. By contrast, heat pumps are generally less exposed to the risk of increasing energy and infrastructure costs due to their high seasonal performance factor. Third, the decision between decentralized and centralized heat pumps requires a case-by-case analysis, considering local heating grid costs, energy efficiency of existing buildings, and potential synergies with combined heat and power and industrial waste heat. High heating densities in cities and neighborhoods with high supply temperatures favor centralized heat pumps. In contrast, decentralized heat pumps seem more economical in rural areas and neighborhoods with lower supply temperatures. For the example of Germany, making this choice should be the focus of the local heating planning processes, which have just started and are due in 2028.

Next to these immediate conclusions in the German context, our research provides a starting point for further research. Future studies may extend our analysis to other countries. Warmer climatic conditions may reinforce the competitive advantage of heat pumps, while other technologies may benefit in colder climates. In addition, it would be interesting to compare expected future energy prices (including price ratios) and grid fees across countries. In doing so, researchers may build on our proposed method to account for uncertainty and heterogeneity and use and extend our primary dataset of relevant input parameters. Finally, further research could address the above-discussed limitations of our study by investigating the role of transition costs, hybrid heating systems, and non-uniform heating choices.

5. Cost and cost distribution of policy-driven investments in decentralized heating systems in residential buildings in Germany

5.1. Introduction

Germany aims to achieve climate neutrality by 2045. Yet most of its 20.8 million residential buildings rely on fossil fuels like natural gas and oil (Statistisches Bundesamt, 2024), and energy efficiency is low (Diefenbach et al., 2016). Decarbonization will require significant investments in heating systems and building envelopes, largely from private households.

To encourage investments in decentralized, low-carbon building energy technologies, Germany employs various policy tools: renewable energy requirements mandate minimum renewable shares for new buildings and heating systems, while subsidies for energy efficiency, heating system replacement, and residential energy generation, along with CO_2 pricing, incentivize shifts toward renewables.

A recent addition to the policy landscape requires 65 % renewable energy for newly installed heating systems, effectively banning fossil-fired systems. This sparked a public debate over transition costs, as renewable systems like electric heat pumps often have higher upfront costs than fossil-fired ones. Opponents argue that, despite subsidies, many homeowners may struggle to cover these costs (Pitel, 2023). Following a heated debate, the policy's start date was postponed and tied to the release of municipal heat plans, which evaluate local district heating and hydrogen options until 2028. This gives homeowners the option to consider decarbonization solutions beyond their immediate decision-making scope.

Despite this delay, Germany's combined policies will increase the decarbonization pressure on building owners. However, a detailed analysis of associated costs, which would facilitate discussions on alleviating these burdens, is lacking. Initial government estimates projected the investment costs for homeowners arising from the renewable energy requirement alone to reach 9 billion EUR and 5 billion EUR annually from 2029 onward. This compares to projected operational cost savings of 11 billion EUR in the next 18 years Deutscher Bundestag (2023). However, it is unclear how other policy elements like subsidies and CO_2 pricing contribute to these costs or how costs are distributed across building types. Given Germany's heterogeneous building stock, costs are likely to differ widely.

Addressing this knowledge gap, this paper calculates policy-induced costs and their distribution across building types. Using a novel application of a building-level energy supply optimization model, we compute optimal investment and operational decisions for decentralized technologies under policy across 794 archetype buildings representing Germany's residential stock. This method enables us to calculate optimal investments, decarbonization, and costs across Germany's residential buildings, capturing the complex interaction of various policy elements in economic decision-making. We focus on the *additional* costs associated with policy by comparing a reference scenario without policy with a scenario incorporating renewable requirements, subsidies, and CO_2 pricing.

Our findings show that, under high medium-term gas prices, moderately increasing electricity prices, and the policies considered, costs vary significantly by building type. Multifamily homes (MFH) with single-story heating systems and buildings with recently installed fossil heating systems face high burdens, mainly due to CO_2 costs. Buildings with low energy demand, on the other hand, can make net benefits from the subsidies.

While employing state-of-the-art methods, our approach has some limitations: we assume rational, cost-optimal decision-making and perfect information, and our scenarios (including sensitivity analyses) only partially address uncertainty in future energy prices. Additionally, our building-level model does not consider ownership structure, potential owner-tenant dilemmata, or technologies requiring broader infrastructure decisions, such as hydrogen heating. Despite these caveats, our results offer valuable insights for policymakers: buildings with high burdens could be prioritized for alternative heat sources in municipal heat planning. Similarly, our findings can inform the design of the CO_2 price revenue recycling mechanism currently discussed by the German government.

The paper is structured as follows: Section 5.2 reviews related literature and highlights this paper's contributions. Section 5.3 details the methodology, including the building energy optimization model and the derivation of the representative buildings. Section 5.4 outlines German building energy policy and introduces the scenarios. Section 5.5 presents the model results. Section 5.6 discusses the results an addresses methodological limitations. Section 5.7 concludes with a summary and directions for further research.[32]

[32] Additional materials, including building lists, technical and economic assumptions, and detailed descriptions of investment decisions, are available at https://doi.org/10.5281/zenodo.12698514.

5.2. Related Literature and Contribution

The literature on German building energy policy is extensive, with many studies using models to simulate building decision-making in response to policy. Two modelling approaches dominate: empirical models and optimization models. Among the empirical models, discrete choice models are a common choice because they allow modelling technology investment. For instance, Bauermann (2016) employs a nested logit model to assess policies like renewable requirements, subsidies, and CO_2 prices across 75 representative German buildings. The model incorporates annualized costs, preferences, and a diffusion lag parameter. Although dated, the results show that combining CO_2 prices and subsidies significantly influences decarbonization and household costs.

Similarly, Özer et al. (2024) combine discrete choice and technology diffusion models for heating technology investments across the EU-27. They explore various price and policy scenarios and find that subsidies and CO_2 prices reduce household sensitivity to energy prices. However, their study does not address the resulting household costs.

Other studies, such as (Frondel and Schubert, 2021, Kirchner et al., 2019), use empirical price-elasticities applied to annual energy demand without explicitly modelling technology investments. Doing so, Frondel and Schubert (2021) estimate household costs under CO_2 pricing in Germany. Kirchner et al. (2019) use empirical price-elasticities in a macroeconomic model to analyze the impact of CO_2 pricing in Austria. Both studies find that CO_2 pricing disproportionately burdens lower-income households, making it regressive.

While having been applied extensively for policy analysis, empirical models often simplify demand by aggregating it on an annual basis (or monthly in Özer et al. (2024)). This simplification makes them computationally efficient but limits their ability to capture the time-varying characteristics of certain technologies, like solar, heat pumps, or storage, and the temporal fluctuations in demand.

To address these complexities, many researchers use optimization models with multiple time steps. These models typically run on hourly resolution across multiple scenario years and incorporate intertemporal constraints. They determine capacity and operational decisions based on cost-minimization. Examples include (Huckebrink and Bertsch, 2022, Knosala et al., 2022, Kotzur et al., 2020), who apply optimization models without explicitly analyzing building energy policy. For example, Kotzur et al. (2020) develop and validate a model for optimal heating technology investments for 200 representative German buildings, while Knosala et al. (2022) analyze ten buildings to identify break-even points between hydrogen- and electricity-based heating under varying energy prices. Huckebrink and Bertsch (2022) develop a model for optimal decarbonization of a sample city. In contrast, Frings and Helgeson (2022) focus on policy impacts, analyzing subsidies and CO_2 pricing for four single-family homes (SFH). They find substantial cost increases under CO_2 pricing.[33] Similarly, Aniello and Bertsch (2023) optimize energy supply for one example SFH under different regulatory scenarios. They show that dynamic grid fees and electricity prices favor electric heat pumps. In a follow-up study, Aniello et al. (2024) find that pricing CO_2 with cost-reflective network charges, instead of subsidies and taxes non-reflective of CO_2, lowers general decarbonization costs. However, for individual households, costs rise without subsidies.

Overall, optimization models effectively capture building sector decision-making, both with and without policy influence. Yet, they are often computationally intensive, as most models include integer variables for piecewise linear investment cost functions. This complexity restricts the number of buildings and scenarios that can be modeled.

Summarizing the existing literature, no single study combines a comprehensive policy analysis for the entire German building stock with a detailed optimization model. Moreover, discussions of cost distribution are rare among studies that use optimization models.

This paper addresses this gap by applying a high-resolution, consumer decision-making model with policy considerations to 794 archetype buildings representing Germany's building stock. By comparing this with a reference scenario, we identify *additional* costs and burdens related to policy-driven investments in decentralized energy technologies. We use these results to discuss cost distribution effects from building energy policy in Germany. Although we do not consider socio-economic factors, our approach bridges the gap between detailed technical-economic modelling under incentive-based policies and simpler price-elasticity models that assess distribution effects.

5.3. Modelling Residential Buildings

Building Optimization Model

We employ a building-level technology investment and operation optimization model to simulate building decision-making under policy. The model, named "Consumer Management of Decentralized Options" (COMODO) was first introduced by Frings and Helgeson (2022). The following offers an overview of the model and its application, with a more detailed description available in Frings and Helgeson (2022) and the online repository for this paper.

COMODO includes 16 different electricity, space heating, and hot water generation and storage technologies. We model only decentralized technologies that generate heat directly in the building and use existing infrastructure. Technologies like hydrogen boilers and district heating, are excluded from this analysis be-

[33]This paper is co-authored by Cordelia Frings.

cause they require higher-level decision-making. Figure 5.1 provides an overview of the available technologies.

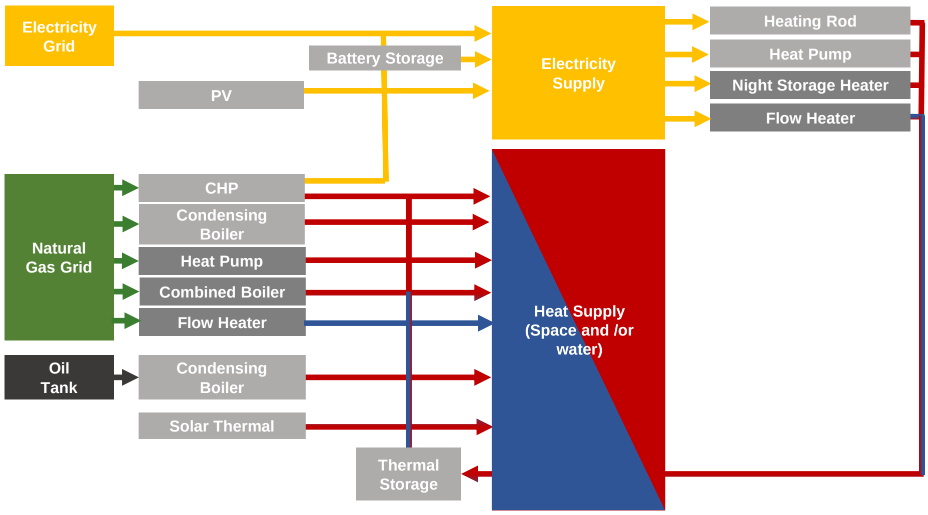


Figure 5.1.: COMODO model overview: Energy flows are shown as lines, and energy demands or supplies as boxes. Yellow represents electricity, red represents space heat, blue represents hot water heat, green represents natural gas, and black represents oil. Technologies are depicted by gray boxes, with those newly introduced for this paper marked in darker gray.

The model covers the period from 2020 to 2045 in five-year increments and simulates building energy supply at an hourly resolution for four representative weeks.[34] Hourly time series for space heating, hot water, and non-heating electricity demands for existing and newly constructed MFH and SFH are based on standard profile guidelines from Verein Deutscher Ingenieure (2019). Hourly photovoltaic (PV) and solar thermal potentials are calculated by determining the global radiation on tilted roof surfaces, accounting for their orientation.

Investment costs are modelled as piecewise linear cost functions in order to account for non-linear scale effects in costs, requiring integer variables. The reduce the computational effort, we reduced the number of integer variables by adjusting the investment and FOM cost functions of the technologies compared to Frings and Helgeson (2022).

The application of the model depends on the building type. SFH are naturally modelled as a singular unit. For MFH, we differentiate between central and single-story heating. MFH with central heating are treated as a single consumer, optimizing energy provision for the entire building. In MFH with single-story heating, each apartment is considered an individual consumer, though all units within a given MFH type are identical. To facilitate MFH analysis, the technology catalog from Frings and Helgeson (2022), which primarily includes central

[34]The representative weeks were derived using an error-minimizing search algorithm and standard k-means procedure.

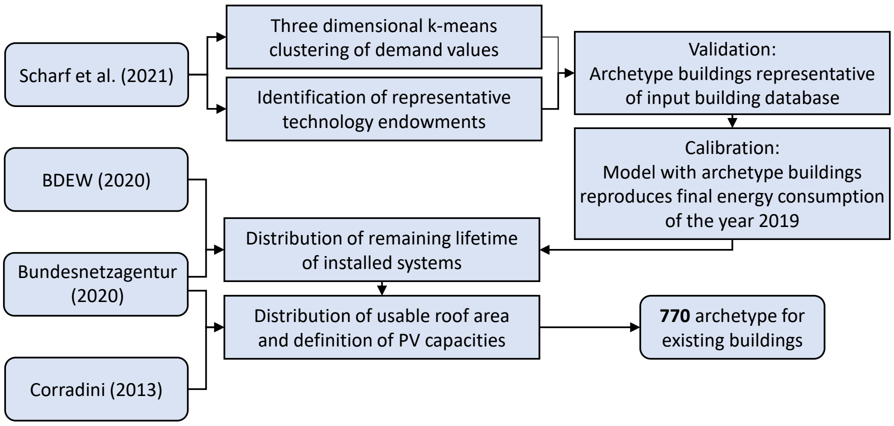


Figure 5.2.: Building aggregation approach

heating systems, was expanded to include single-story heating technologies, such as gas boilers and split heat pumps.

Investment decisions in the model are constrained by building-specific characteristics, such as available roof area for PV and solar thermal installations. Additionally, the technology choice is constrained by the heating circuit's flow temperature requirements. All technologies must be replaced after reaching their technology-specific assumed lifetime. Consumers may also replace technologies prematurely if the operating costs of existing systems exceed the investment costs for new systems.

Representative Buildings

We derive a set of 770 archetype buildings that are representative for the existing residential building stock in Germany. The database provided by Scharf et al. (2021)[35], which includes energy demand and installed heating technology data for Germany's 2019 building stock, serves as a basis. We match their data with data on additional building attributes, catering to the input requirements of the building optimization model. Figure 5.2 illustrates the approach for determining the archetype buildings.

We distinguish between SFH and two types of MFH: Buildings with up to 3 apartments and buildings with more than 3 apartments. Each building is characterized by three annual demand values: space heating, hot water heating, and non-heating electricity. Within each building type, we define several demand categories to capture variations in building efficiency and household size. Using a three-dimensional k-means clustering approach, we identify 13 representative combinations of demand for the existing building stock.

[35]This work was co-authored by Fabian Arnold as part of the *Erdgas Bridge* research project, supported by the German Federal Ministry for Economic Affairs and Energy.

Regarding existing technologies, we categorize buildings based on their heating sources: oil, gas, heat pump, night storage, and *other* (including biomass, district heating, liquid gas, and coal). To determine the distribution of each technology type within the 13 identified building categories, we first calculate the share of each technology's contribution to meeting demand based on the underlying database. We then adjust these shares to align with the final energy consumption of German residential buildings in 2019, as reported by AGEB (2021). The representative buildings are further characterized by heating system age, rooftop space, and existing PV installations, following distributions from BDEW (2020), Corradini (2013), and Bundesnetzagentur (2023c), respectively.[36]

For new builds, we define 24 building types based on EnEV 55 and EnEV 40 efficiency standards for buildings constructed before and after 2030, respectively.[37] The new buildings are equipped with electric heat pumps and PV systems by default.

The selection of representative buildings enables the model to capture various characteristics of the German building stock. Using the 13 identified demand combinations, we can closely replicate the demand distribution from Scharf et al. (2021).[38] The buildings also reflect the distribution of heating system types and age in the existing stock, as well as the solar installation potential. However, by focusing on representative buildings, we exclude outliers, such as those with unusually high or low demand or rare system combinations. A complete list of the archetype buildings is included in the online repository for this paper.

5.4. Building Energy Policy

5.4.1. Current Legislation

German building energy policy includes renewable energy requirements for new and replacement heating systems, lump-sum investment subsidies, feed-in tariffs for PV and CHP, and CO_2 prices. Together, these elements create a complex incentive structure for building energy investments. According to the *Law on Building Energy* (German: GEG), new heating systems must achieve a renewable energy share of 65 %. Renewable systems include electric heat pumps and direct electric heaters, hybrid systems, and biomass heating with wood pellets. The renewable requirement currently applies to new buildings, while for existing buildings, the requirement's start date depends on the *Law on Heat Planning*

[36]Additional details on building definitions are available in the online repository.

[37]EnEV refers to the *Energy Saving Ordinance*, which set efficiency standards before the *Law on Building Energy* was passed (see next section). EnEV standards 55 and 40 indicate percentage energy savings compared to a reference building.

[38]See Figures D.1 and D.2 in D.1.

and Decarbonization of Heating Networks (German: WPG).[39] Until municipal heat planning is finalized, building owners are not required to meet the 65 % renewable requirement. Thus, installing conventional gas boilers is still allowed, provided building owners undergo obligatory consultation.

However, for gas systems installed between January 1, 2024, and the publication of municipal heat plans, gas systems must operate with at least 15 % climate-neutral gas, such as from biomass or hydrogen, beginning in 2029.[40] MFH with single-story heating systems have an exemption from the 65 % renewable requirement. If a single-story boiler fails and needs replacement, the decision to centralize heating must be made within five years, with implementation required within eight years. If single-story heating continues, all new boilers must meet the 65 % renewable requirement five years after the first boiler's failure. Exceptions and hardship provisions apply to all parts of the law.

The 65 % renewable requirement is supported by federal investment subsidies under the *Guideline for Federal Funding for Efficient Buildings - Individual Measures* (German: BEG EM). Homeowners can receive a one-time subsidy of 30 %, with additional subsidies of 30 % for lower-income households and 20 % for early system replacement (valid until 2028).[41] An extra 5 % subsidy applies to heat pumps that use natural refrigerants or certain heat sources. Households may combine bonuses, though total subsidies are capped at 70 % of costs. Additional lump-sum subsidies of up to 20 % are available for efficiency measures, such as building refurbishment. Furthermore, the KfW, a semi-state-owned bank, offers low-interest loans for specific heating technologies and building envelope improvements.

Additionally, residential electricity generation by PV is subsidized through the general German RES support scheme, *Law on the Expansion of Renewable Energies* (German: EEG). Homeowners receive feed-in tariffs, which encourage them to install rooftop PV systems and feed excess electricity into the grid. The PV feed-in tariffs also affect the opportunity costs for using electric technologies in combination with PV, such as electric heating or storage.

Beyond technology-specific funding mechanisms, the *Law on National Certificate Trading for Fuel Emissions* (German: BEHG) implements a national CO_2 price for sectors not covered by the EU-ETS. Under this scheme, consumers in the transport, building, and non-EU-ETS industrial sectors pay per ton of CO_2 emitted from fuel combustion. The CO_2 price encourages both energy consumption reduction and fuel switching, such as replacing fossil heating systems. CO_2 prices are widely recognized as effective tools for incentivizing emission reductions. Weitzman (1974) argues that compared to direct quantity controls, CO_2

[39] The WPG requires federal states to develop heating plans (covering district heating and hydrogen) by June 30, 2026, for cities over 100,000 residents and by June 30, 2028, for smaller municipalities.

[40] This renewable share will rise to 30 % by 2035 and 60 % by 2040.

[41] The additional subsidy decreases by 3 percentage points every two years beginning in 2029 and phases out after 2036.

pricing is suitable for incentivizing abatement across many units, as those with lower abatement costs reduce emissions first. In Germany, CO_2 prices will rise from 25 EUR/tCO_2 in 2021 to 55 EUR/tCO_2 in 2025. After 2025, prices will be set by a market for CO_2 certificates.

5.4.2. Scenario Design

To estimate *additional* costs associated with building energy policy, we set up two scenarios. The *reference* scenario computes the optimal investment and operational decisions for the archetype buildings in a business-as-usual setting, free from policy influence. The *policy* scenario includes key elements of German building energy policy, assessing their impact on decentralized building energy technologies. Comparing these scenarios allows us to identify additional decarbonization efforts and costs introduced by the policies, thereby isolating anyway costs (unavoidable costs).

Reference and Baseline Economic Assumptions

Economic decision-making for energy technologies depends on fixed and operational costs, which vary according to building-specific demands. Fixed costs include both fixed operational expenses and capital costs, defined as the annualized investment costs over the technology's lifetime.[42] All economic assumptions are in real terms, reflecting 2020 levels.

Fuel prices are assumed to be exogenous. Oil and natural gas prices are based on projections from the German Federal Environment Agency's 2023 report (Mendelevitch et al., 2022). End-user prices include taxes, fees, and surcharges at 2020 levels.

End-user electricity prices, including wholesale rates, taxes, fees, and surcharges, follow a price path based on assumptions for the individual components. Wholesale electricity prices are based on market modelling to ensure consistency with gas prices and climate targets and were derived using an updated version of the electricity market model used in (EWI, 2021).[43] Taxes are assumed constant, with electricity taxed at ct/kWh 2.05 and VAT at 19 %. Grid fees are projected to increase by 19 % by 2030 (vs. 2018), 27 % by 2040, and 33 % by 2050 (Mendelevitch et al., 2022). We account for the end of the EEG surcharge in 2023. Electricity for heat pumps is assumed to receive a reduced tariff, set at 90 % of the general end-consumer electricity price.

A summary of fuel price assumptions for end-consumers is presented in Table 5.1.

[42] Costs are discounted at 1.6 %, based on the long-term borrowing rate from European Central Bank (2021).

[43] For further details, see D.2.1.

Table 5.1.: End-consumer fuel price development (ct/kWh)

	2020	2025	2030	2035	2040	2045
Oil	5.1	6.9	5.8	5.8	5.7	5.7
Gas	6.5	10.8	7.4	7.3	7.1	7.0
Electricity	32.2	30.5	26.6	28.4	28.9	30.0

Electricity generated by existing PV systems and fed into the grid is compensated at either the market value or existing feed-in tariffs. We assume that consumers opt to sell electricity directly if electricity prices exceed the fixed feed-in tariffs. The electricity price for selling electricity is based on annual market values, calculated as the wholesale price multiplied by the technology-specific value factor. The eligibility for feed-in tariffs continues until the end of the existing PV system's life (20 years).[44]

Policy Scenario

In the *policy* scenario, buildings must meet a 65 % renewable energy requirement starting in 2025. This requirement mandates that new investments produce at least 65 % of heat demand (for space heating and domestic hot water) from renewable sources. Thus, we neglect the link between individual (GEG) and municipal heat planning (WPG) in the model. The impact of this assumption is discussed in Section 5.6.

Buildings receive two types of subsidies that reduce investment costs: lump-sum subsidies per the BEG EM, and feed-in tariffs for electricity generated from PV systems. Lump-sum subsidies are set at 30%, reflecting the BEG EM's basic support for renewable investments.

Electricity generation from newly installed PV panels is subsidized with fixed feed-in tariffs. According to Art. 49, EEG, these tariffs decline by 1 % monthly, reaching 6.2 ct/kWh for SFH and 5.4 ct/kWh for MFH for systems installed in 2025, and 3.4 ct/kWh and 2.9 ct/kWh, respectively, for systems installed in 2030. After 2030, market values are higher than the feed-in tariffs.

Additionally, CO_2 prices increase the operational costs of fossil technologies in proportion to fuel-specific emission factors and system efficiency, raising the relative cost of high-emission technologies. Following German energy policy, electricity is assigned an emission factor of zero since emissions are accounted for within the electricity sector. The BEHG sets the CO_2 price to rise from 24 EUR/tCO_2 in 2021 to 38 EUR/tCO_2 in 2025.[45] After 2025, prices will emerge

[44] Details on market values, PV system shares, and feed-in tariffs by construction year are available in D.2.1 and D.2.2 and on the online repository.

[45] In nominal terms: 25 EUR/tCO_2 and 45 EUR/tCO_2 respectively. Note that at the time of writing, the CO_2 price for 2025 was still under debate and was since then set to 55 EUR/tCO_2.

from a market for CO_2 certificates. Based on Mendelevitch et al. (2022), we project an increase to 196 EUR/tCO_2 by 2045.

5.5. Results

5.5.1. Investments in the Reference Scenario

Under the economic assumptions of the *reference* scenario, gas boilers are the optimal choice for the primary heating system across nearly all building types. Even buildings with existing electric or gas heat pumps switch to gas boilers. Replacements occur only when existing boilers reach their end-of-life since previous investments are considered sunk. New buildings, lacking pre-existing heating systems, mainly install gas boilers in combination with simple power-to-heat units for peak loads. As an exception, some newly built small MFH install electric heat pumps, benefiting from economies of scale and low energy demands. Thus, heat pumps can be optimal even without policy intervention if no existing heating system with sunk costs is in place.

Figure 5.3 summarizes the primary technology investments, additional systems, and investment timing. The color code indicates fuel types: green for electric heat pumps, red for gas-fueled systems, and gray for oil heating. For categories where only a portion of buildings switches fuels, the color represents a weighted mix based on the number of buildings[46] using each heating technology.

In addition to the primary heating system, many buildings invest in PV, battery storage, solar thermal, and thermal storage systems to reduce electricity and hot water costs amid rising energy prices. Buildings with a PV option install PV by 2040 and many invest in batteries to increase self-consumption. Buildings with high electricity demand invest in batteries by 2030 if they already have PV, while smaller-demand buildings delay battery investments until 2045, when battery costs decrease.

Many high-demand buildings also add solar thermal or electric flow heaters, reducing energy and boiler capacity costs. Most buildings install simple power-to-heat units for peak loads, lowering new boiler capacity costs.

5.5.2. Investments in the Policy Scenario

In the *policy* scenario, heating investment decisions are influenced by the 65 % renewable requirement, lump-sum subsidies, feed-in tariffs, and CO_2 prices.

As shown in Figure 5.4, all buildings eventually install electric heat pumps, at latest when their existing heating systems reach end-of-life. Under policy-driven decarbonization pressure, many buildings invest early, foregoing the benefit from

[46] Building numbers are provided in the building list on the online repository.

Heating technology in 2019	Building type	System failure year	Primary heating system (color) and CO_2 intensity (value)						Additional technologies in 2045		
			2019	2025	2030	2035	2040	2045	PV	Battery	Solar thermal
Oil boiler	SFH	2025	250	165	166	164	162	163	57%	27%	20%
Oil boiler	SFH	2030	250	250	180	164	162	164	57%	27%	20%
Oil boiler	SFH	2035	250	250	250	164	162	163	57%	27%	20%
Oil boiler	SFH	2040	250	250	250	250	162	163	57%	27%	20%
Oil boiler	SFH	2045	250	250	250	250	228	164	57%	27%	20%
Oil boiler	sMFH	2025	256	158	163	163	163	163	55%	55%	53%
Oil boiler	sMFH	2030	256	230	163	163	163	163	55%	55%	53%
Oil boiler	sMFH	2035	256	230	226	164	163	163	55%	55%	53%
Oil boiler	sMFH	2040	256	227	230	230	164	164	55%	55%	41%
Oil boiler	sMFH	2045	256	235	230	230	230	164	55%	55%	41%
Oil boiler	lMFH	2025	260	144	145	145	145	145	26%	26%	100%
Oil boiler	lMFH	2030	260	198	145	145	145	145	26%	26%	100%
Oil boiler	lMFH	2035	260	198	198	145	145	145	26%	26%	100%
Oil boiler	lMFH	2040	260	199	199	199	146	145	26%	26%	100%
Oil boiler	lMFH	2045	260	199	199	199	199	145	26%	26%	100%
Gas boiler	SFH	2025	171	148	150	150	149	162	55%	27%	31%
Gas boiler	SFH	2030	171	167	174	163	162	162	55%	27%	31%
Gas boiler	SFH	2035	171	169	170	163	162	162	55%	27%	31%
Gas boiler	SFH	2040	171	169	170	170	161	162	55%	27%	31%
Gas boiler	SFH	2045	171	169	170	170	164	162	55%	27%	31%
Gas boiler	sMFH	2025	181	159	165	164	164	164	53%	53%	55%
Gas boiler	sMFH	2030	181	157	165	165	165	164	53%	53%	55%
Gas boiler	sMFH	2035	181	157	163	165	165	164	53%	53%	55%
Gas boiler	sMFH	2040	181	158	163	165	165	165	53%	53%	55%
Gas boiler	sMFH	2045	181	158	163	163	163	165	53%	53%	55%
Gas boiler	lMFH	2025	194	151	151	150	150	150	21%	21%	100%
Gas boiler	lMFH	2030	194	151	151	150	150	150	21%	21%	100%
Gas boiler	lMFH	2035	194	151	151	150	150	150	21%	21%	100%
Gas boiler	lMFH	2040	194	151	151	151	150	150	21%	21%	100%
Gas boiler	lMFH	2045	194	151	151	151	150	150	21%	21%	100%
Gas heat pump	sMFH	2040	207	193	193	192	192	192	52%	52%	0%
Gas heat pump	sMFH	2045	206	206	206	206	206	206	52%	52%	0%
Gas single-story	sMFH	2025-2045	134	120	125	125	178	178	57%	57%	0%
Gas single-story	lMFH	2025-2045	134	120	125	125	125	178	18%	18%	0%
Elec. heat pump	SFH	2035	0	0	0	157	153	159	100%	73%	0%
Elec. heat pump	SFH	2040	0	0	0	0	153	159	100%	73%	0%
Elec. heat pump	SFH	2045	0	0	0	0	0	159	100%	73%	0%
New build < 2035	SFH	-	-	126	127	127	133	133	100%	53%	0%
New build < 2035	sMFH	-	-	64	69	69	69	83	100%	100%	41%
New build < 2035	lmFH	-	-	100	109	109	109	109	100%	100%	100%
New build ≥ 2035	SFH	-	-	-	-	112	119	119	100%	53%	0%
New build ≥ 2035	sMFH	-	-	-	-	71	71	71	100%	100%	41%
New build ≥ 2035	lmFH	-	-	-	-	96	96	96	100%	100%	100%

Figure 5.3.: Investment and timing and CO_2 footprint in the *reference* scenario. Note: Colors represent installed primary heating systems by year and building category, with red for gas, gray for oil, and green for electric heat pumps. Mixed colors indicate the weighted number of buildings using each technology if choices vary. Numbers show average CO_2 intensity in g/kWh of heating. The right columns list the percentage of buildings with PV, batteries, and solar thermal installations in 2045 by category.

Heating technology in 2019	Building type	System failure year	Primary heating system (color) and CO_2 intensity (value)						Additional technologies in 2045		
			2019	2025	2030	2035	2040	2045	PV	Battery	Solar thermal
Oil boiler	SFH	2025	250	0	0	0	0	0	57%	0%	20%
Oil boiler	SFH	2030	250	231	0	0	0	0	57%	0%	20%
Oil boiler	SFH	2035	250	231	227	0	0	0	57%	0%	20%
Oil boiler	SFH	2040	250	227	227	224	0	0	57%	0%	20%
Oil boiler	SFH	2045	250	231	228	226	178	0	57%	0%	20%
Oil boiler	sMFH	2025	256	0	0	0	0	0	55%	55%	59%
Oil boiler	sMFH	2030	256	218	0	0	0	0	55%	55%	59%
Oil boiler	sMFH	2035	256	218	122	0	0	0	55%	55%	59%
Oil boiler	sMFH	2040	256	218	122	76	0	0	55%	55%	59%
Oil boiler	sMFH	2045	256	218	122	76	0	0	55%	55%	59%
Oil boiler	lMFH	2025	260	0	0	0	0	0	26%	26%	100%
Oil boiler	lMFH	2030-2045	260	197	0	0	0	0	26%	26%	100%
Gas boiler	SFH	2025	171	0	0	0	0	0	55%	8%	31%
Gas boiler	SFH	2030	171	104	0	0	0	0	55%	8%	31%
Gas boiler	SFH	2035	171	112	112	0	0	0	55%	8%	31%
Gas boiler	SFH	2040	171	112	112	112	0	0	55%	8%	31%
Gas boiler	SFH	2045	171	112	112	113	111	0	55%	12%	31%
Gas boiler	sMFH	2025	181	0	0	0	0	0	53%	53%	55%
Gas boiler	sMFH	2030	181	0	0	0	0	0	53%	53%	55%
Gas boiler	sMFH	2035	181	26	26	0	0	0	53%	53%	55%
Gas boiler	sMFH	2040	181	26	26	26	0	0	53%	53%	55%
Gas boiler	sMFH	2045	181	26	26	26	0	0	53%	53%	55%
Gas boiler	lMFH	2025	194	0	0	0	0	0	21%	21%	100%
Gas boiler	lMFH	2030	194	4	0	0	0	0	21%	21%	100%
Gas boiler	lMFH	2035	194	4	2	0	0	0	21%	21%	100%
Gas boiler	lMFH	2045	194	4	3	3	3	0	21%	21%	100%
Gas single-story	sMFH	2025	207	47	48	48	48	46	57%	57%	0%
Gas single-story	sMFH	2030	207	120	49	48	48	47	57%	57%	0%
Gas single-story	sMFH	2035	207	189	192	48	47	47	57%	57%	0%
Gas single-story	sMFH	2040	207	189	192	192	46	46	57%	57%	0%
Gas single-story	sMFH	2045	207	189	192	192	164	46	57%	57%	0%
Gas single-story	lMFH	2025	206	45	41	41	38	36	18%	18%	82%
Gas single-story	lMFH	2030	206	202	42	42	38	38	18%	18%	82%
Gas single-story	lMFH	2035	206	202	198	41	37	37	18%	18%	82%
Gas single-story	lMFH	2040	206	202	198	198	36	36	18%	18%	82%
Gas single-story	lMFH	2045	206	202	198	198	194	36	18%	18%	82%
Gas heat pump	sMFH	2040	134	64	64	64	0	0	52%	52%	0%
Gas heat pump	sMFH	2045	134	64	64	64	64	0	52%	52%	0%
Elec. heat pump	SFH	2035-2045	0	0	0	0	0	0	100%	0%	0%
New build < 2035	SFH	-	-	0	0	0	0	0	100%	53%	0%
New build < 2035	sMFH	-	-	0	0	0	0	0	100%	100%	41%
New build < 2035	lMFH	-	-	0	0	0	0	0	100%	100%	100%
New build ≥ 2035	SFH	-	-	-	-	0	0	0	100%	53%	0%
New build ≥ 2035	sMFH	-	-	-	-	0	0	0	100%	100%	41%
New build ≥ 2035	lMFH	-	-	-	-	0	0	0	100%	100%	100%

Figure 5.4.: Investment and timing and CO_2 footprint in the *policy* scenario. Note: Colors represent installed primary heating systems by year and building category, with red for gas, gray for oil, and green for electric heat pumps. Mixed colors indicate the weighted number of buildings using each technology if choices vary. Numbers show average CO_2 intensity in g/kWh of heating. The right columns list the percentage of buildings with PV, batteries, and solar thermal installations in 2045 by category.

using existing technologies with sunk costs. MFH, which have high capacity demands often invest early due to economies of scale in the technology costs. Among the buildings that invest prematurely, buildings with gas boilers invest by 2025 to avoid high gas prices. Oil-boiler buildings invest after 2030 when CO_2 prices increase. In contrast, buildings with single-story gas heating rarely invest early, as they have to rely on small-scale air-to-air heat pumps for decentralized decarbonization. This technology is not expected to have economies of scale.

All buildings with a PV option install PV by 2025. Electric flow heaters or solar thermal systems are added for hot water decarbonization. Larger buildings invest in battery storage systems, though less frequently than in the *reference* scenario. Feed-in tariffs for PV make grid feed-in more profitable than self-consumption in the *policy* scenario.

Many buildings add simple power-to-heat units to reduce the capacity needs of the primary heating system. Some MFH retain their existing gas boilers for peak heating, as savings on heat pump capacity outweigh gas boiler costs and CO_2 expenses.

5.5.3. Costs and Cost Distribution

Decarbonization policies lead to additional costs compared to the *reference* scenario, as they drive investment in capital-intensive technologies. We distinguish between *full costs*—investment, FOM, and operational costs—and the household *burden*. The burden includes policy-induced transfer payments, i.e., subsidies to building owners and CO_2 payments by households and represents the net costs for the buildings.

In general, the results indicate that the earlier an existing system is replaced, the higher the full costs. Buildings with older systems or attributes encouraging early investment thus have higher additional costs. Due to scale effects, MFH generally incur lower full costs per residential unit than SFH. Figure 5.5 shows individual full costs and specific burdens per unit and across different relevant building characteristics. The costs are expressed as additional expenses over the *reference* scenario from 2020 to 2045. [47]

For most buildings, the burden per unit is less than full costs, meaning they gain net benefits from policies (orange and white areas). Orange represents buildings with high full costs ($> 10,000$ EUR), while white represents those with relatively low full costs ($< 10,000$ EUR). However, in some cases, per-unit burdens exceed full costs, mainly due to CO_2 payments (blue area). A few buildings experience net gains, with burdens lower than in the *reference* scenario due to subsidies (green area).

[47] Buildings with night storage heaters or *other* heating technologies are excluded, as they reinvest in existing technologies. Typically, their burdens are lower than their full costs, as they install subsidized technologies like PV and solar thermal.

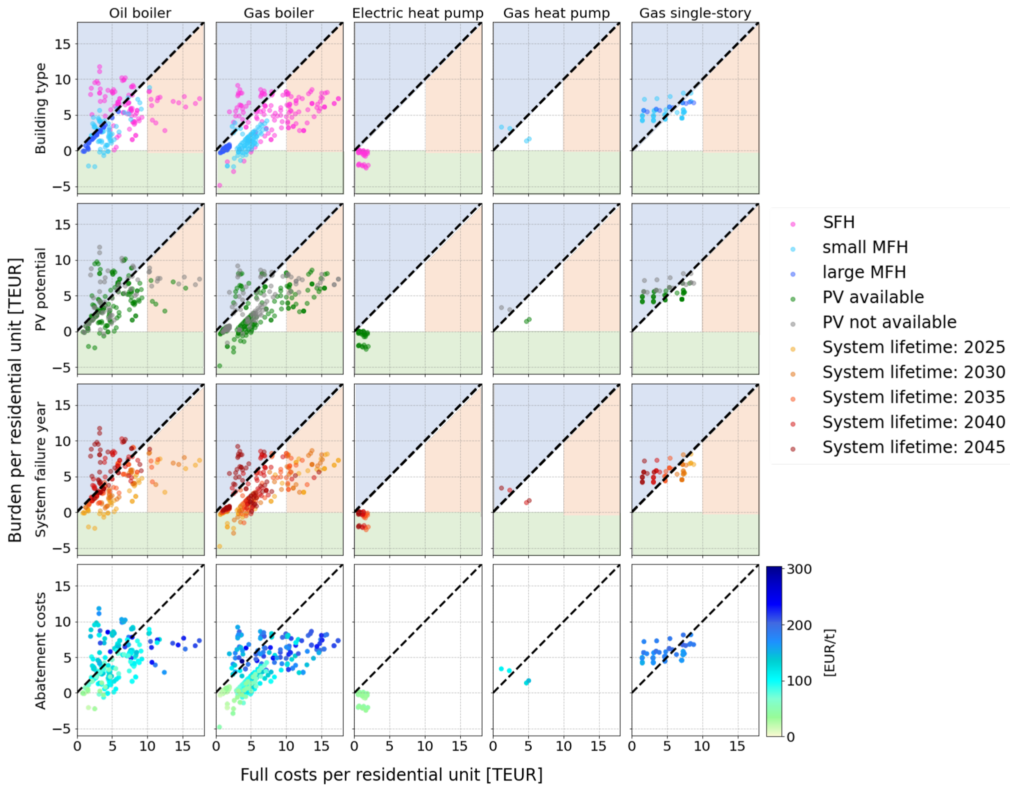


Figure 5.5.: Burden vs. full costs per residential unit by heating system, building type, PV potential, system failure year, and abatement costs from 2020-2045.

Orange Area: Burden < Additional Full Costs, High Additional Full Costs Buildings in the orange area exhibit the highest additional full costs. This category includes SFH with existing oil and gas boilers, especially those with high specific heat demands (> 160 kWh/m^2) and older heating systems. These systems must be replaced early with electric heat pumps, leading to high full costs. The burden for these buildings is lower than full costs (below the dashed line in Figure 5.5), as the government partially covers expenses through feed-in tariffs and subsidies. Early replacement also results in low CO_2 price expenses. Having a PV option further reduces the burden via feed-in tariffs, although it increases full costs. Gas-heated buildings face higher costs than oil-heated ones, as they often invest earlier due to high medium-term gas prices when heat pump costs remain relatively high. Overall, the policies effectively drive substantial decarbonization for these buildings while reducing household burdens.

In the literature, policy efficiency is often evaluated by abatement costs, i.e., the cost per tonne of CO_2 saved. From a cost-saving perspective, it is logical to prioritize decarbonization where abatement costs are lowest. Ideally, a merit order of abatement options could assess if policy measures achieve cost-efficient decarbonization. However, deriving such a curve would require multiple model runs with sequential reductions in allowed CO_2 emissions, which is beyond this paper's scope. Based on the snapshot of average abatement costs in this scenario, orange-area buildings have relatively high abatement costs. This is largely because SFH cannot benefit from economies of scale, resulting in higher per-unit heat pump investment costs compared to MFH.

White Area: Burden < Additional Full Costs, Low Additional Full Costs Buildings in the white area exhibit additional full costs below $10,000$ EUR, which are partly covered by the state (burden < full costs). Buildings in this area are diverse. For instance, this group includes SFH with older systems, lower specific heating demands, and low flow temperatures. These SFH require lower capacities, leading to lower investment costs compared to high-demand SFH. Heat pumps are more efficient at low flow temperatures, reducing energy costs. Consequently, SFH in the white area invest earlier than those in the orange area, achieving higher abatement at lower abatement costs.

MFH with centralized heating also fall into the white area. They incur lower per-unit costs due to economies of scale in large centralized systems, reducing costs per kW of heating capacity. Thus, full costs and burdens per unit decrease as the number of residential units increases. PV options further lower burdens through additional subsidies. MFH in this category achieve substantial low-cost abatement, suggesting that policies effectively promote decarbonization while minimizing the burden.

Additionally, MFH with gas single-story heating fall into the white area, if their existing heating system reaches end-of-life until 2030. Subsidies reduce their burdens, but these buildings exhibit high abatement costs because they have to rely on split heat pumps without economies of scale. In the case of all MFH it has to be kept in mind that inhabitants are often renters and incentives for decarbonization could be distorted by the owner-tenant dilemma, which is discussed in Section 5.6.2.

Blue Area: Burden > Additional Full Costs

MFH with newer gas-fueled single-story heating systems generally do not switch to heat pumps early. Consequently, they incur high CO_2 price expenses, resulting in burdens that exceed full costs (positioned above the dashed line). These buildings have limited decarbonization options, leading to high abatement costs.

SFH and small MFH with new oil or gas boilers, especially without PV options, are also in the blue area, where burdens exceed full costs. In one case, the CO_2 price burden nearly doubles total costs. The highest burdens ($> 11,000$ EUR) are observed in SFH with high specific heat demands and oil boilers that fail in 2045, which cannot install PV. For these buildings, using the existing boiler until its end-of-life is optimal, despite the policies. As a result, they incur high CO_2 costs. Buildings with gas heat pumps and no PV options also fall into the blue category, though to a lesser extent, as the heat pump's efficiency reduces energy and CO_2 costs.

Green Area: Profits

Decarbonization policies generate net profits for buildings with existing fossil boilers that have low energy demands, older heating systems, and a PV option. These buildings, located in the green area, incur low additional full costs due to minimal capacity needs. Subsidies and feed-in tariffs overcompensate their additional costs, resulting in windfall gains. The lowest burden (approximately $-4,800$ EUR) is observed in SFH with the lowest specific heat demand (101 kWh/m^2), where the gas heating system requires replacement in 2025, and the flow temperature is 35 °C. This well-insulated, modern house has minimal additional full costs, as the electric heat pump is nearly optimal even without policies. In this case, subsidies drive significant decarbonization.

Similarly, buildings with existing electric heat pumps make net profits from subsidies. They achieve the highest gains if their PV system fails in 2025, allowing them to invest in new PV and receive high feed-in tariffs, resulting in a negative burden of around $-2,000$ EUR. However, it should be noted that these buildings recently faced high investment costs for electric heat pumps, which are treated as sunk costs in this analysis.

5.6. Discussion

5.6.1. Robustness of the Results

The results showed that the combination of policy elements significantly impacts optimal decision-making for decentralized technologies. Thus, German building energy policy could drive substantial decarbonization by encouraging the replacement of fossil-fueled heating with electric heat pumps. This finding aligns with Bauermann (2016), who shows that both subsidies and renewable energy requirements or CO_2 pricing promote investments in heat pumps and other renewable technologies. Regarding household costs, Bauermann (2016) shows that under subsidies and renewable requirements, total household heating costs do not exceed historical values — without however analyzing the cost distribution. Similarly, Aniello et al. (2024) using an optimization model for two example SFH, conclude that German subsidies favor electric heat pumps and PV. Their findings on household costs support our result that subsidies can create a net benefit over gas boiler and solar thermal heating (which is comparable to our *reference* scenario).

In addition to policy-driven technology choices and costs, our findings reveal that decision-making strongly depends on building characteristics, such as energy demand, existing heating technology, and system age. Although there are differences in scenarios and technology sets, the impact of building type on optimal heating technology is also confirmed by Knosala et al. (2022) and Kotzur et al. (2020). Both studies show that optimal investments vary between SFH and MFH and by renovation standards, which relate to demand. However, neither study considers heating system age, despite our findings showing that remaining system lifetime has a significant effect on optimal technology choice and costs.

Knosala et al. (2022) further demonstrate that energy prices can greatly influence optimal heating technology investments by varying electricity and hydrogen prices systematically. To test the robustness of our results under changing energy prices, we analyze an alternative scenario with strictly rising electricity prices, detailed in D.3 in the Appendix.

Our analysis indicates that the results in the *policy* scenario are robust against higher electricity prices, as policy elements, such as the 65 % renewable energy requirement, mandate decarbonization by 2045. Figure D.3 in the Appendix provides an overview of the *policy* scenario results under price sensitivity assumptions. Similar to the main scenario, most buildings install electric heat pumps and, where possible, PV by 2045. However, the incentive for premature heat pump investment decreases relative to the main scenario. Buildings with gas-fueled systems face a trade-off between medium-term high gas prices and long-term high electricity prices. Consequently, buildings with high energy demands and long remaining lifetimes for existing boilers opt to avoid early replacement. Some MFH continue using gas technologies long-term, meeting the

65 % renewable requirement with solar thermal systems, additional electric heating, batteries, and PV. Similarly, some MFH choose gas heat pumps over electric heat pumps. Buildings with oil boilers do not replace systems prematurely under high electricity prices.

In summary, increased electricity prices raise energy costs and slow decarbonization. Investment costs remain similar to the main scenario, as most buildings eventually adopt electric heat pumps. However, household burdens increase due to higher energy and CO_2 costs.

5.6.2. Additional Policy Aspects

Incentives for Building Envelope Efficiency

Increasing building envelope efficiency and reducing heat demand are not included in the endogenous decision-making of the model used in our analysis. Likewise, buildings cannot adjust their flow temperature. Evaluating building envelope efficiency and related costs requires detailed analysis of efficiency measures and anyway costs[48]. For example, Kotzur et al. (2020) demonstrate that refurbishment becomes optimal primarily when it aligns with regular cosmetic maintenance cycles, allowing many costs to qualify as anyway costs.

Yet, our results provide preliminary insights into the role of building envelope improvements, as we model buildings with varying energy demands and flow temperatures but otherwise similar characteristics. For example, in SFH, there is a burden difference of $5,000 - 12,000$ EUR between high-demand (with high flow temperature) and low-demand (with low flow temperature) buildings. Lower-demand buildings invest in heat pumps sooner, benefiting from lower capacity costs, subsidies, and avoiding CO_2 and gas costs. This burden difference represents the maximum amount SFH might pay for a 50 % demand reduction and a flow temperature change. In Germany, refurbishment is incentivized with lump-sum subsidies up to 20 % or a maximum of $60,000$ EUR, and under the BEG EM, homeowners can access low-interest loans. This increases the appeal of refurbishment, potentially leading to earlier heating system investment in SFH.

In MFH with central heating, the burden difference between high and low-demand buildings is lower at around $3,000$ EUR per residential unit. For these buildings, investment timing is less dependent on specific demand. Decarbonization occurs early in any case, so cost differences between high and low demand buildings arise solely from energy costs. Thus, while decarbonization impact is minor, increased efficiency reduces electricity demand and infrastructure needs. Contrarily, in MFH with single-story heating, the burden difference reaches up to $8,000$ EUR per unit for buildings with recent systems. Here, a demand reduction could significantly cut energy and CO_2 costs.

[48]In the case of efficiency measures, this refers to costs associated with general maintenance, such as roof repair, not specifically efficiency improvements (c.f. Galvin, 2023).

Overall, our results suggest that refurbishment efforts should focus on SFH and MFH with single-story heating to maximize decarbonization, but further research is needed to evaluate costs and burdens.

Technology Options, Infrastructure, and Municipal Heat Planning

Our decentralized decarbonization model excludes technologies requiring centralized planning, such as district heating or climate-neutral hydrogen. In densely populated areas, heat pump-powered district heating could offer lower-cost heating, utilizing additional heat sources like industrial waste heat or CHP and enabling cross-sector synergies (c.f. Manz et al., 2024, Moritz et al., 2024). We also exclude hydrogen heating from the available technology options. Rosenow (2022) conclude in a review that hydrogen heating is typically viable only at low hydrogen prices or as hybrid heating that uses (repurposed) existing infrastructure. Moritz et al. (2024) suggest that hydrogen heating could be feasible in rural areas if electricity costs are high.

As noted in Section 5.4, all German municipalities must publish infrastructure plans for hydrogen and district heating. These municipal heat plans will heavily influence the extent of decentralized decarbonization, as modeled in this paper. Our results could inform these plans by providing a benchmark for a transition based solely on decentralized technologies. Policymakers could prioritize buildings with high costs or burdens for alternative heat sources like district heating or hydrogen.

Before municipal heat plans are finalized, it remains possible to install non-compliant systems, like gas boilers. However, owners must ensure renewable gas access by 2029. Whether this leads to more gas boiler installations than our results suggest depends on future costs and the availability of renewable gases, which remain uncertain. Recent data on electric heat pump sales shows a 52 % drop in wholesale sales between Q4 2023 and Q1 2024. Overall, new heating investments declined by 29 %. The Federation of the German Heating Industry attributes this to consumer hesitation after the political debate surrounding the new rules (c.f. Bundesverband der deutschen Heizungsindustrie (BDH), 2024). Policymakers should monitor this trend and mitigate uncertainties that may impact household decisions.

Incentives for Centralizing Single-Story Heating

Our analysis excludes the centralization of heating in MFH with single-story systems. Our results show that these buildings achieve minimal decarbonization and incur high costs under CO_2 pricing due to limited decarbonization options. The cost difference between MFH with central versus single-story heating ranges from $3,000$ to $7,000$ EUR per residential unit. If costs for measures like new piping or temporary housing during construction fall below this range, centralization could be financially viable. Policymakers already recognize centralization of single-story heating in MFH as an important decarbonization measure, implementing extended transition periods for these buildings under the 65 % renewable requirement. Centralization could boost decarbonization, as premature investment is optimal in centrally heated MFH under the *policy* scenario. However, recent census data indicates that 84 % of MFH residents are renters (Statistisches Bundesamt, 2024), which may limit their influence on heating system investments. The resulting owner-tenant incentive dilemma and its potential impact are discussed in the next subsection.

Owner-Tenant Dilemma

The owner-tenant dilemma arises from conflicting incentives between building owners (who own the heating system) and tenants (who pay for heating use). Owners seek to minimize investment and maximize subsidies, while tenants prioritize energy costs, including CO_2 expenses. This dilemma can discourage investments in costly but efficient heating technologies or refurbishment (c.f. Kühn et al., 2024). Policymakers recognize this issue and have introduced the *Law on the Allocation of Carbon Dioxide Costs*, which shifts part of the CO_2 cost burden to owners in buildings with high per m^2 emissions.

In our results, capital costs represent a significant share of additional expenses for buildings that invest in heat pumps early. This suggests that early investments in tenant occupied MFH may not materialize in practice, leading to slower decarbonization and lower owner investment costs, while tenants bear higher CO_2 expenses. Once heating systems reach their end-of-life, the 65 % renewable requirement mandates a system change. However, instead of electric heat pumps, owners might choose lower-capital solutions, such as solar thermal, battery storage, power-to-heat, and gas systems. This would, again, leave tenants with higher CO_2 expenses and reduce decarbonization compared to our results.

Distributional Fairness

Despite the additional factors discussed above, our results show that building type heterogeneity leads to varying cost burdens when investing in decentralized technologies. The introduction of CO_2 prices, which create significant transfers from households to the state, sparked a heated debate on distributional fairness since 2020. Currently, the only policy that considers household socio-economic status is the speed bonus under BEG EM, available only to owner-occupiers (typically SFH). This bonus could encourage early investment in SFH, reducing CO_2 burdens compared to our results. Additionally, BEG EM offers a bonus to owner-occupiers with a taxable income of under $40,000$ EUR, which is not considered in our analysis but may further reduce SFH burdens.

To address future distributional fairness, the current German government's coalition agreement includes a plan to recycle CO_2 revenue through a "climate payment" (SPD et al., 2021). However, the exact recycling mechanism is still undecided. Studies show that CO_2 pricing often has a regressive effect, shifting costs from lower- to higher-income households (e.g. Frondel and Schubert, 2021, Kirchner et al., 2019). Frondel and Schubert (2021) and Kirchner et al. (2019) discuss several recycling options, such as lump-sum payments, tax cuts, or social benefits. While lump-sum payments are incentive-neutral, other mechanisms could impact decarbonization. Kirchner et al. (2019) even find a trade-off between decarbonization efficiency and progressivity. These analyses do not consider existing subsidies, which are funded by taxes, Therefore, subsidies already constitute a redistribution mechanism — albeit, according to our results, one with unequal impacts on different building types.

5.6.3. Methodological Limitations

While our analysis provides valuable insights for policymaking, some methodological limitations must be considered when interpreting the results. Our model optimizes building energy provision purely from a cost perspective, ignoring non-monetary preferences that individual consumers might have, and how these preferences influence decision-making.

Additionally, the model assumes consumers have perfect foresight and complete information, whereas in reality, future (and current) fuel and technology costs are uncertain. Thus, the emission and cost estimates here represent a lower benchmark, as they are based on optimal, perfectly informed technology sizing.

Finally, our model does not account for dynamic interactions with other sectors. In practice, residential energy consumption impacts electricity generation, as well as the infrastructure and cost requirements of electricity and gas grids. Although our sensitivity analysis shows that results are robust against higher electricity prices, the 65 % renewable requirement remains the primary driver of investment decisions, with energy prices mainly influencing the timing of premature investment. However, the model does not capture the endogeneity of building energy demand with respect to energy prices and infrastructure costs.

5.7. Conclusion

This study quantifies the costs and distribution of investments in decentralized heating decarbonization driven by building energy policy. We model the investment decisions in decentralized heating technologies for 794 archetype buildings, representing the German residential building stock, considering renewable energy requirements, subsidies, and CO_2 prices. Under these policies and in a scenario with high medium-term gas prices and moderately increasing electricity prices, we find that many households opt to replace fossil systems with electric heat pumps, achieving rapid decarbonization.

Compared to a reference scenario without policy intervention, the policies increase costs burdens for most building types, though these burdens vary significantly. Some buildings face high burdens, while others benefit from subsidies. Key findings include:

- In MFH with centralized heating, economies of scale for electric heat pumps result in low abatement costs, and subsidies further reduce burdens. These buildings are ideal for decentralized decarbonization, though the owner-tenant dilemma may hinder decision-making.
- In MFH with single-story heating, abatement costs are high due to limited decarbonization options, leading to CO_2 cost burdens of up to $8,000$ EUR between 2020 and 2045. These buildings should consider centralizing heating or exploring alternatives like district heating or hydrogen. The owner-tenant dilemma here also affects optimal choices.
- Single-family homes with recently installed oil and gas systems—often recently subsidized to replace older boilers—face the highest cost burdens, up to $11,000$ EUR, due to significant future CO_2 costs.
- The latter finding warns against investing in new fossil systems before the 65 % renewable requirement takes effect by 2028. Policymakers should work to reduce information asymmetries on this issue.
- Buildings with particularly low heat demands benefit more from the current subsidy system than necessary and even make net profits.

In terms of policy implications, our results reveal that burdens and benefits vary across building types, suggesting a need for additional measures to achieve fair redistribution. While the results are specific to the German case, they hold a warning for policymakers anywhere because they show that combining different transfer-based policy elements can lead to unwanted redistribution. Redistributional fairness is also a potential topic for further research: To support redistribution policy design, future studies could integrate our findings with residents' socio-economic profiles and ownership structures.[49] Additionally, research could focus on redesigning German building energy policy by assessing the impact of individual policy elements, using our *reference* scenario as a benchmark. Finally, our method could be applied to other building stocks, such as non-residential buildings or different countries.

[49]Our results are available for download on the online repository, together with additional descriptions of the results, methods and assumptions.

A. Supplementary Material for Chapter 2

A.1. Notation

Throughout the paper at hand, the notation presented in table A.1 is used. To distinguish (exogenous) parameters and optimization variables, the latter are written in capital letters.

Table A.1.: Sets, parameters and variables

Sets		
$i \in I$		Electricity generation and storage technologies
$m, n \in M$		Markets
$l \in L$		Transmission Grid Lines
$c \in C$		Linear independent cycles of modeled grid
$y, y1 \in Y$		Years
$d \in D$		Representative Days
$h \in H$		Hours
Parameters		
$demand(y, d, h, m)$	[MWh]	Electricity demand
$avail(y, d, h, m, i)$	[-]	Availability of technology
$eff(i, m)$	[-]	Efficiency of technology
$linecap(y, m, n)$	[MW]	Available transmission capacity
$\beta(y)$	[-]	Discount factor
$\delta(y, i)$	[EUR/MW]	Annualized investment cost
$\sigma(i)$	[EUR/MW]	Fixed operation and maintenance cost
$\gamma(y, i)$	[EUR/MWh]	Variable generation cost
$cap_{add,min}(y, m, i)$	[MW]	Capacities under construction
$cap_{sub,min}(y, m, i)$	[MW]	Decommissioning of capacity due to lifetime or policy bans
$l(m, n)$	[-]	Relative transmission Losses
$\kappa(m, l)$	[-]	Incidence matrix
$\phi(l, c)$	[-]	Cycle matrix
Variables		
$CAP(y, m, i)$	[MW]	Electricity generation capacity
$GEN(y, d, h, m, i)$	[MWh]	Electricity generation
$CAP_{add}(y, m, i)$	[MW]	Investments in electricity generation capacity
$CAP_{sub}(y, m, i)$	[MW]	Decommissioning of electricity generation capacity
$TRADE(y, d, h, m, n)$	[MWh]	Electricity trade from m to n
$TRADE\_BAL(y, d, h, m)$	[MWh]	Net trade balance of m
$FLOW(y, d, h, l)$	[MWh]	Power flow along line l
TC	[EUR]	Total costs
$FC(y)$ / $VC(y)$	[EUR]	Yearly fixed or variable costs

A.2. Power market model

A.2.1. Basic model

[50]

The central planner invests into new power plants and dispatches generation capacities such that the net present value of the variable (VC) and fixed costs (FC) is minimized, where β represents the discount factor.

The objective is hence:

$$min!\ TC = \sum_{y \in Y} \beta(y) \cdot [VC(y) + FC(y)].$$

Installed electricity generation capacities (CAP) are modeled endogenously: The model invests in new generation capacities (CAP_{add}) and decommissions capacities (CAP_{sub}), which are not profitable. For a realistic depiction of European energy markets, existing as well as under construction capacities ($cap_{add,min}$) and decommissioning due to end-of-lifetime or technology bans ($cap_{sub,min}$) are given exogenously. These parameters serve as lower bounds for building or decommissioning capacities, respectively. The fixed costs per year comprise the annualized investment costs (δ) plus fixed operation and maintenance costs (σ) per installed capacity. The following equations describe these interrelations.

$$\begin{aligned}
CAP(y,m,i) &= CAP(y-1,m,i) + CAP_{add}(y,m,i) - CAP_{sub}(y,m,i) \\
CAP_{add}(y,m,i) &\geq cap_{add,min}(y,m,i) \\
CAP_{sub}(y,m,i) &\geq cap_{sub,min}(y,m,i) \\
&\forall y \in Y, \forall m \in M, \forall i \in I
\end{aligned}$$

$$\begin{aligned}
FC(y) = &\sum_{m \in M, i \in I} CAP(y,m,i) \cdot \sigma(i) \\
&+ \sum_{y1: y-y1 < econ_lifetime(i)} CAP_{add}(y1,m,i) \cdot \delta(y,i)
\end{aligned}$$

Electricity generation (GEN) in each market, day (d) and hour (h) has to level the (inelastic) *demand* minus the trade balance ($TRADE\_BAL$), which depicts the net imports of trade flows ($TRADE$) from other markets. Availability of power plants ($avail \cdot CAP$), which, e.g., considers maintenance shutdowns limit their generation. Trade flows between markets are limited by interconnection capacities ($linecap$). Yearly total variable costs (VC) result from the generation

[50] We set up the basic model according to Schmidt and Zinke (2023), to which we refer for further information on the methodology.

per technology times the technology-specific variable operation costs (γ), which mainly comprise costs for burnt fuel and required CO_2 allowances.

$$
\begin{aligned}
\sum_{i \in I} GEN(y,d,h,m,i) &= demand(y,d,h,m) - TRADE\_BAL(y,d,h,m) \\
GEN(y,d,h,m,i) &\leq avail(y,d,h,i) \cdot CAP(y,m,i) \\
TRADE\_BAL(y,d,h,m) &= \sum_{n} (1 - l(n,m)) \cdot TRADE(y,d,h,n,m) - TRADE(y,d,h,m,n) \\
TRADE(y,d,h,m,n) &\leq linecap(y,m,n) \\
&\forall y \in Y, \forall m,n \in M \;\; \& \;\; m \neq n, \forall i \in I \\
VC(y) &= \sum_{m \in M, i \in I, d \in D, h \in H} GEN(y,d,h,m,i) \cdot \gamma(y,i)
\end{aligned}
$$

A.2.2. Storage equations

The charging level of storage ($STORLEVEL$) is determined by the level in the previous time step and the net-balance of electricity charged and withdrawn. The level cannot exceed the storage volume which is given by the installed capacity and an exogenous ratio of capacity and volume (vol_factor).

$$
\begin{aligned}
STOR\_LEVEL(y,d,h,m,i) &= STOR\_LEVEL(y,t-1,m,i) \\
&\quad - eff(m,i)\cdot GEN(y,d,h,m,i) + eff(i,m)\cdot GEN(y,d,h,i,m) \\
STOR\_LEVEL(y,d,h,m,i) &\leq STOR\_VOL \\
STOR\_VOL &= avail(y,d,h,i)\cdot vol\_factor(i)\cdot CAP(y,m,i) \\
&\quad \forall y \in Y, \forall d \in D, h \in H, \forall m \in M, \forall i \in I_{Storage}
\end{aligned}
$$

The amount of energy which can be shifted between typedays (DAY_SALDO) is limited according to the number of days that a typeday represents (d_rep). The total of the energy shifted by storage must add up to zero.

$$
\begin{aligned}
DAY\_SALDO(y,d,m,i) &= \sum_{h\in H}(GEN(y,d,h,i,m) - GEN(y,d,h,m,i)) \\
DAY\_SALDO(y,d,m,i)\cdot d\_rep(d) &\leq STOR\_VOL(y,m,i) \\
DAY\_SALDO(y,d,m,i)\cdot d\_rep(t) &\geq -STOR\_VOL(y,m,i) \\
\sum_{d\in D} DAY\_SALDO(y,d,m,i) &= 0 \\
&\quad \forall y \in Y, \forall d \in D, \forall m \in M, \forall i \in I_{Storage}
\end{aligned}
$$

A.3. Assumptions on technologies, demand and fuel prices

Table A.2.: Considered technologies and their generation efficiency, assumptions based on scenario *Stated Policies* in World Energy Outlook 2021 (IEA, 2021) and Knaut et al. (2016)

Technologies	Efficiency
Nuclear	0.33
Lignite	0.4
Coal	0.45
Combined Cycle Gas Turbines (CCGT)	0.5
Open Cycle Gas Turbines (OCGT)	0.38
Oil	0.4
Biomass	0.3
PV	1
Wind Onshore	1
Wind Offshore	1
Hydro	1
Pumped Storage	0.78
Battery Storage	0.95

Table A.3.: Development of fuel and carbon prices [EUR/MWh_{th}], based on scenario *Net Zero Emissions* in World Energy Outlook 2022 (IEA, 2022)

Fuel	2019	2030
Uranium	3.0	3.0
Lignite	3.9	4.0
Coal	7.9	7.7
Natural Gas	13.6	25.9
Oil	33.1	44.9
Biomass	21.0	23.0
Carbon [EUR/tCO2]	24.9	95.0

Table A.4.: Development of demand [TWh], for Germany based on BMWK (2022a) and for all other countries on scenario *National Trends* in ENTSO-E (2020a)

Country	2019	2025	2030
AT	67	77	79
BE	85	87	91
CH	62	62	61
CZ	63	73	78
DE	524	600	715
DK	35	52	46
FR	456	496	486
NL	114	114	119
PL	156	181	182

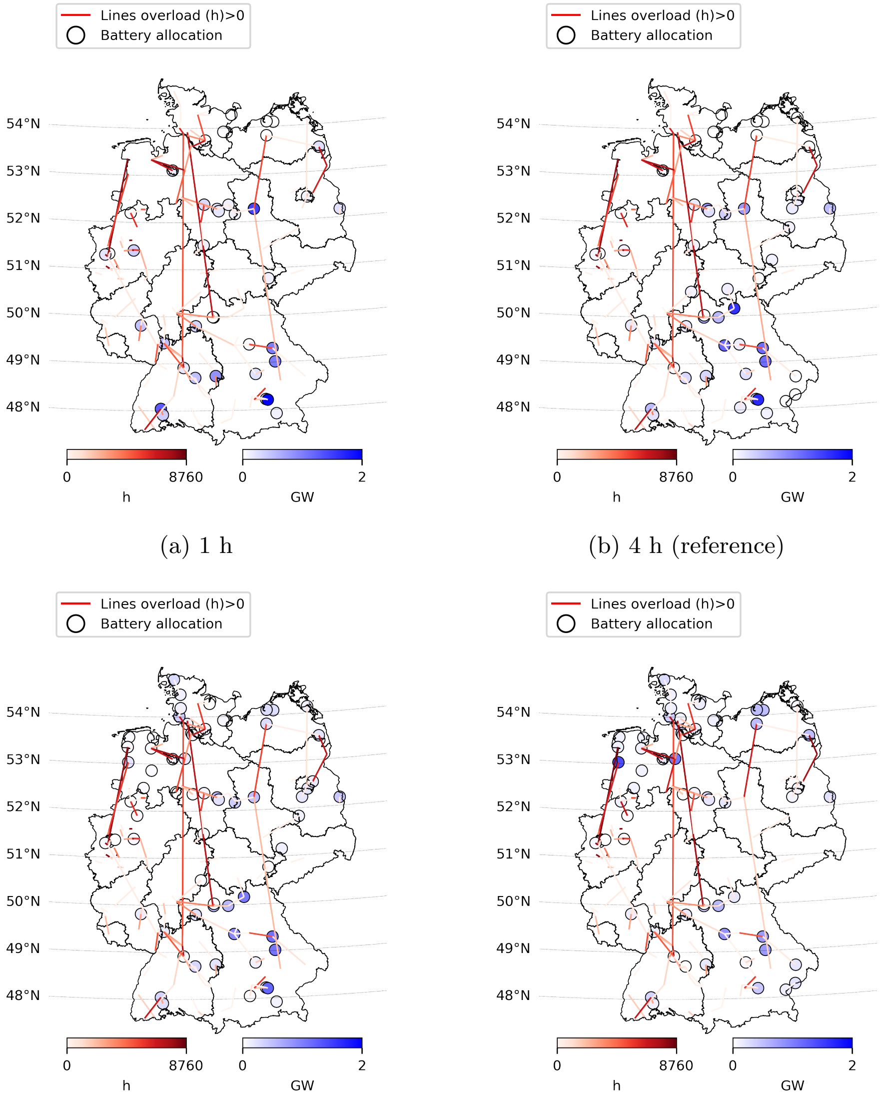
A.4. Sensitivity analyses

A.4.1. Volume factor

Figure A.1 shows variations of the volume factor, i.e., the ratio between connected power (GW) and the energy volume (GWh) of a storage technology. Low volume factors correspond to battery storage, while higher factors can be seen for technologies using a different energy carrier for storage, e.g,. hydrogen. Storage allocation depends significantly on the volume factor. For higher volume factors (¿4h), storage moves northwards and closer to wind generation. Here, they buffer volatile wind generation and increase utilization of the congested lines along the structural grid bottleneck. However, even for higher volume factors, significant capacities are allocated in the south of Germany. Even when volume factors are above 100h and the majority of storage is located above the 52nd parallel, storage is needed to buffer volatile PV infeed in the south.

A.4.2. Battery capacity

Figure A.2 shows sensitivity analyses for the total installed capacity of batteries for a given distribution of wind and solar generation according to the nodal setting. The allocation of batteries close to grid bottlenecks along the 53rd parallel as well as in the south of Germany is robust. In the case of 15 and more GW of batteries, saturation in those areas leads to an allocation in the north, close to wind generation centers. The sensitivity analyses, therefore, highlights again the role of batteries in balancing short-term volatility from demand and solar feed-in time series as opposed to wind generation that requires longer storage of electricity.



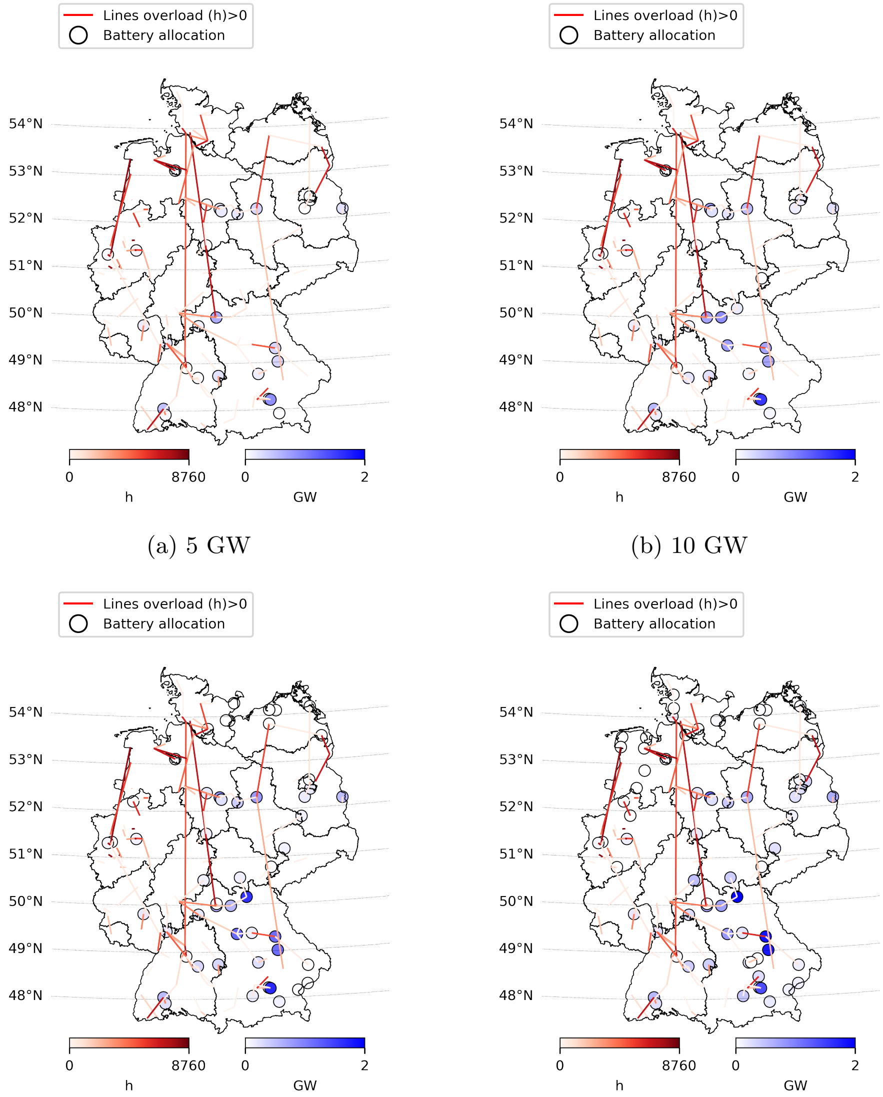
(a) 1 h

(b) 4 h (reference)

(c) 50 h

(d) 200 h

Figure A.1.: Optimal battery allocation based on the distribution of wind and solar in the uniform setting for different battery volume factors



(a) 5 GW

(b) 10 GW

(c) 15 GW (reference)

(d) 20 GW

Figure A.2.: Optimal battery allocation based on the distribution of wind and solar in the uniform setting for different battery capacities

B. Supplementary Material for Chapter 3

B.1. Assumptions on technologies, demand and fuel prices

Table B.1.: Considered technologies and generation efficiency, assumptions based on scenario *Stated Policies* in World Energy Outlook 2021 (IEA, 2021) and Knaut et al. (2016)

Technologies	Efficiency
Nuclear	0.33
Lignite	0.4
Coal	0.45
CCGT	0.5
OCGT	0.38
Oil	0.4
Biomass	0.3
PV	1
Wind Onshore	1
Wind Offshore	1
Hydro	1
Pumped Storage	0.78
Battery Storage	0.95

Table B.2.: Development of demand [TWh] based on the *National Trends* scenario in ENTSO-E and ENTSO-G (2022)

Country	2019	2030
AT	67	83
BE	85	95
CH	62	64
CZ	63	74
DE	524	595
DK	35	53
FR	456	485
NL	114	139
PL	156	182

Table B.3.: Development of fuel prices [EUR/MWh_{th}], based on scenario *Stated Policies* in World Energy Outlook 2022 (IEA, 2022)

Fuel	2019	2030
Uranium	3.0	5.5
Lignite	3.9	5
Coal	7.9	7.7
Natural Gas	13.6	25.0
Oil	33.1	44.8
Biomass	21.0	22.0

C. Supplementary Material for Chapter 4

C.1. Related literature and research gap

With this article, we add to a large body of literature that deals with the question of how to decarbonize residential heating. Researchers approach this question at different scopes, ranging from individual buildings over districts to regional or national energy systems. Furthermore, they use a variety of methods, such as technical simulations and optimization models. Table C.1 gives an overview of the relevant literature for the example of Germany. While previous studies have covered the important aspects of building heterogeneity, fuel price uncertainty, and infrastructure individually, none have captured all of them.

Table C.1.: Parameters considered in this study compared to other studies

Publication	Building sector heterogeneity	Infrastructure heterogeneity and uncertainty	Energy price uncertainty	Heat pump cost uncertainty
Chaudry et al. (2015)			✓	✓
Kisse et al. (2020)	for one neighbourhood	✓		
Kotzur et al. (2020)	✓			
Wuppertal-Institut et al. (2020)	✓	ex-post		
EWI (2021)	✓	ex-post		
Fraunhofer ISI et al. (2021)	✓	✓		
Knosala et al. (2022)		indirectly via end consumer price variation	✓	
Lux et al. (2022)		✓		
Czock et al. (2025)	✓		electricity prices only	
Billerbeck et al. (2024)	✓	✓		
Our analysis	✓	✓	✓	✓

First, Kotzur et al. (2020) and Czock et al. (2025) focus on representing building sector heterogeneity by applying optimization models for individual buildings to large sets of archetype buildings. Kotzur et al. (2020) show that at least 200 archetype buildings are needed to represent building diversity accurately, and Czock et al. (2025) use even 770 archetype buildings to reflect building heterogeneity, including the type and age of existing heating systems. Kotzur et al. (2020) neglect infrastructure costs and fuel price uncertainty. Czock et al. (2025) perform a sensitivity analysis on electricity prices but keep other energy prices fixed. Second, using a similar individual building model, Knosala et al. (2022) model uncertainty in energy prices. They calculate optimal energy provision over a range of hydrogen and electricity prices. However, their analysis is limited in considering heterogeneity (only 10 different building types) and infrastructure costs (only current grid fees). Third, Lux et al. (2022) and Kisse et al. (2020) focus on the costs of hydrogen transport and electricity distribution infrastructure, respectively. On the other hand, these studies simplify the building stock's heterogeneity and neglect future fuel price uncertainty. Note that Kisse et al. (2020) do reflect local heterogeneity in a case study for one neighborhood. Their results cannot be generalized for the German building stock.

Another set of studies considers both building sector heterogeneity and infrastructure costs (EWI, 2021, Fraunhofer ISI et al., 2021, Wuppertal-Institut et al., 2020). This is typically done through the coupling of different models. For example, EWI (2021) and Wuppertal-Institut et al. (2020) both soft-couple bottom-up models of the German building stock with energy market optimization models to determine a decarbonization pathway for Germany until 2045. However, infrastructure costs for electricity, hydrogen, and methane are quantified ex-post and not considered in the choice of heating technologies. By contrast, Fraunhofer ISI et al. (2021) and Billerbeck et al. (2024) endogenize infrastructure costs. Another difference is that Billerbeck et al. (2024) only consider transmission infrastructure costs, while Wuppertal-Institut et al. (2020) and Fraunhofer ISI et al. (2021) also include costs of distribution grids. Across this type of studies, uncertainty is typically neglected (Wuppertal-Institut et al., 2020) or represented only through a small set of scenarios (Billerbeck et al., 2024, EWI, 2021, Fraunhofer ISI et al., 2021). This can be explained by the modeling being computationally too expensive for a more detailed uncertainty analysis. Scenario variation typically concerns the shares of electricity and hydrogen in decarbonization, and none of the studies explicitly focuses on price uncertainty. Chaudry et al. (2015) incorporate fuel price and technology cost uncertainty and calculate levelized costs of decentralized heating in the UK by running a simple individual building model over a range of inputs. However, they do not consider heterogeneous building types.

Despite the differences in methods, most studies conclude that a mix of decentralized heating with heat pumps and district heating is generally the most feasible option for the building sector. Decentralized hydrogen heating is either viewed as an edge-case at very low hydrogen prices or as a backup option, except for EWI (2021), who assume a slower diffusion of heat pumps and the repurposing of gas grids for hydrogen instead. Centralized hydrogen heating more likely plays a role, especially in energy system studies that model combined heat and power (CHP) plants. This finding is not a German particularity but coherent with a review of international studies on residential building decarbonization (Rosenow, 2022).

Given the question of *cost-efficiency* in heating, researchers mostly opt for optimization-based approaches, which are often computationally expensive. Some studies resort to using heuristic searchers instead. In both types of studies, different methods exist to represent the building stock and to model infrastructure. Fuel price uncertainty, if modeled, is usually represented by varying assumptions and comparing a limited number of scenarios. None of the reviewed studies explicitly model uncertainty, for example, in a systematic Monte Carlo or stochastic approach. Ultimately, there seems to be a trade-off between the level of detail in representing building stock heterogeneity, infrastructure cost (especially distribution level), and fuel price uncertainty. Given the methodological difficulties, a research gap arises with regard to the robustness of existing results on future optimal heating decarbonization against the relevant heterogeneity and uncertainties.

C.2. Equipment cost data and functions

We collected list prices for the German market from the manufacturers Buderus, Carrier, Elco, Vaillant, Viessmann for the following components: air-to-air heat pumps, air-to-water heat pumps, water-to-water heat pumps, gas-condensing boilers, electric boilers, electric instant water heaters, buffer tanks, hot water tanks, and heating rods. Moreover, we collected data on the installation costs of gas-condensing boilers and AtW heat pumps in Germany from the installation firms Alfons Rott GmbH & Co. KG, E. Altmann GmbH, Guido Schaefer GmbH, König GmbH & Co. KG, Moritz & Barmer GmbH, Octupus Energy, Thermondo, Wilhöft Heizungsbau GmbH. We fit a cost function to the collected data, with installed capacity as an independent variable. We employ nonlinear least squares fitting using the curve fit function from the SciPy (scipy.optimize) library to estimate the parameters of functions from the data. We fit linear functions without intercept ($f(x) = mx$), linear functions with intercept ($f(x) = mx + b$), and power functions ($f(x) = ax^b$), where $f(x)$ represents the costs, and x represent the installed capacity. We choose the one with the lowest RMSE from the three fitted functions. In the case of gas condensing boilers, a 2-step piecewise-linear function resulted in the best fit. This function reflects that boilers with a heating capacity below 50 kW are relatively cheaper than larger boilers because they typically have factory-installed control and are produced in larger numbers. In the case of district heating stations, we assume equipment costs of 4000 EUR for a heating capacity of up to 15 kW as these are off-the-shelf products. This assumption is based on personal communication with the manufacturer Pewo Energietechnik GmbH. Based on personal communication with Habo Wärmetechnik GmbH & Co. KG, district heating stations with larger capacities are typically individually designed. We use a power function provided by Blesl et al. (2023) for district heating stations with larger capacities. In order to be able to reflect the variance in the data, we generate high-cost and low-cost functions. High-cost functions are the fitted functions plus 1/3 of the standard error, and low-cost functions are the fitted functions minus 1/3 of the RMSE. The primary data and fitted functions are shown in Figure 4.1.

Some cost functions cannot be directly derived from data. Hydrogen boilers are not yet available commercially. According to personal communication with the manufacturer Viessmann, the sales prices of hydrogen boilers will be around of 10 % higher than those of natural gas boilers. Thus, our investment cost function for hydrogen-condensing boilers is the cost function of gas-condensing boilers multiplied by 1.1.

In the same fashion, we calculate the installation costs of district heating stations and electric boilers based on the installation costs of gas-condensing boilers. According to personal communication with the heating company Moritz & Bramer GmbH, the installation of a district heating station costs 10 % less than the installation of a gas condensing boiler since no chimney system is necessary. Installing an electric boiler costs 20 % less since neither a chimney system nor gas piping is necessary. We assume identical installation costs for AtW and WtW heat pumps as we calculate the costs of the groundwater well separately. The fixed operation and maintenance costs are parametrized as a function of the installed capacity based on personal communication with Moritz & Bramer GmbH and can be found in C.2. The annual FOM costs of the geothermal probe for WtW heat pumps are calculated as 3 % of the investment costs (c.f. npro energy (2023)).

Typically, installation companies add a contribution margin to the material costs to cover their administrative expenses. We assume a contribution margin of 50 % to all major equipment units. Costs for small materials are included in the installation cost functions, which are displayed in Figure 4.1.

Regarding energy efficiencies of boilers, gas condensing boilers can have an efficiency of 95 % under optimal conditions (according to manufacturer's information by Buderus, Elco, Vailland and Viessmann). However, a detailed in-situ study in the United Kingdom showed that average efficiencies are 82 % (GASTEC, 2009). A reason for lower efficiencies is that return temperatures are too high to condense the water in the boiler exhaust gas fully. For our analysis, we assume an efficiency of 90 % for gas and hydrogen condensing boilers and neglect the effect of the supply temperature on the boiler efficiency. For electric boilers, we assume an energy efficiency of 99 % according to manufacturer's information by Buderus.

The calculation of installation costs for AtA heat pumps is based on personal communication with Aircon-Technik GmbH. We calculate the installation costs bottom-up depending on the heating capacity by:

$$f(x) = w(t_{out}n_{out} + t_{in}n_{in} + t_{line}l_{line}) + l_{line}sc_{line} + n_{in}sc_{cond} + n_{branches}sc_{branch} \quad \text{[EUR]} \tag{C.1}$$

, where $t_{in} = 0.5$ are person days per inside unit, $t_{out} = 1$ are person days per outside unit, $t_{line} = 1/48$ are person days per meter of refrigeration line, $P_{in} = 2$ is the average power of an inside unit kW, $P_{out,max} = 85$ is the largest outside unit available in the manufacturer's price lists, $sc_{branch} = 200$ is are the specific costs of a refrigeration line branch in EUR, $bpu = 1$ are the number of refrigeration line branches per inside unit, $sc_{line} = 20$ are the specific costs of a refrigeration line canal in EUR/m, $w = 600$ are the specific wages per person day in EUR/d, $n_{in} = x/P_{in}$ are the number of inside units, $n_{out} = x/P_{out,max}$ are the number of outside units, where x is the heating capacity of the building in kW, $n_{branches} = n_{in}bpu$ are the number of branches, and $l_{line} = n_{in}sl_{line}$ is the total length of refrigeration line. We generate ranges for the installation costs by varying the costs for the condensate pump and the length of the refrigeration lines. $sl_{line} = [2.5; 7.5]$ is the range for the specific average refrigeration line length per inside unit in m/inside-unit, and $sc_{cond} = [0 - 100]$ is the range for the specific costs of condensate pump per inside unit EUR/inside-unit. Equation C.3

can be simplified to $f(x) = 388.31x$, where x is the heating capacity and $f(x)$ are the installation costs in EUR.

C.3. Calculation of heating system investment costs

We design AtW and WtW heat pump systems for bivalent monoenergetic operation. The heat pump is designed to cover the heat load of the building at the bivalence point. The heating rod is designed so that, together with the heat pump, it covers the heating load of the building at the standard outside temperature. The standard outside temperature is defined as the lowest two-day average value reached or fallen below ten times in 20 years. The bivalence point and the standard outside temperature depend on the climate zone. We use the reference climate for Germany in accordance with DIN V 18599-10 (reference location Potsdam). The standard outside temperature in the reference climate is -12.7°C, and the corresponding bivalence point is -5°C (according to DIN EN 12831). For the design of AtW and WtW heat pump system, we approximate the COP of the heat pump as

$$COP^{AtW,WtW} = 0.5 \frac{T_{supply}}{T_{supply} - T_{out}}, \quad T \text{ in [K]} \tag{C.2}$$

, where T_{supply} is the supply temperature of the heating system and T_{out} is the outside ambient air temperature. The supply temperature depends on the outside temperature. The maximal T_{supply} is required to provide an inside temperature of 20°C at the standard outside temperature. We estimate the T_{supply} at the bivalence point, assuming a linear heating curve (c.f. Bader and Ihle (2021)). We design AtA heat pump systems for monovalent operation. The heat pump is designed to cover the heat load of the building at the standard outdoor temperature point. For the design of the AtA heat pump system, we approximate the COP with a formula taken from Eguiarte et al. (2020)

$$COP^{AtA} = 2.85633 + 0.072432 T_{out} + 0.000546578 T_{out}^2, \quad T \text{ in [°C]} \tag{C.3}$$

, where T_{out} is the outside temperature.

We calculate the investment costs of heating systems, excluding heat distribution outside or within the building. In decentralized heating, these investment costs are the specific investment costs of each building's heating system. In centralized heating, these investment costs are the specific investment costs of the central heat generation system and the decentralized district heating stations in each supplied building. The heat pumps and boilers in most decentralized heating are designed to cover heating and hot water demand. Only in AtA heat pump systems is hot water generated by an electric instant water heater. In centralized heating, the heating capacity is designed to be smaller than the heat load of all supplied buildings due to a simultaneity factor. Buffer and hot water storages are designed according to typical specific capacities Buderus (2019). Table C.2 shows key assumptions of the investment cost calculation.

Table C.2.: General techno-economic assumptions

Parameter	Unit	Value
Energy efficiency of gas and hydrogen boilers	[-]	0.90
Energy efficiency of electric boilers	[-]	0.99
Interest rate	[%]	5
Depreciation period	[yr]	20
Full load hours of heating technologies	[h/yr]	2000
FOM AtW and WtW heat pumps decentralized	[EUR/kW$_{\mathrm{th}}$/yr]	25
FOM AtW and WtW heat pumps centralized	[EUR/kW$_{\mathrm{th}}$/yr]	2.5
FOM gas and hydrogen boiler decentralized	[EUR/kW$_{\mathrm{th}}$/yr]	20
FOM gas and hydrogen boiler centralized	[EUR/kW$_{\mathrm{th}}$/yr]	2.5
FOM of district heating stations	[EUR/kW$_{\mathrm{th}}$/yr]	20
FOM of ground water well	[% of CAPEX/yr]	3
Specific heat load of buildings	[W/m^2]	50
Specific hot water demand	[kWh/occupant/yr]	500
Heated area per occupant	[m^2]	30
Specific heat load for domestic hot water	[W/occupant]	200
Specific buffer storage capacity for decentralized heat pumps	[l/kW$_{\mathrm{th}}$]	200
Heating capacity of heat pumps at bivalent point	[kW$_{\mathrm{th}}$/kW$_{\mathrm{th}}$ specific heat load]	0.73
Heating capacity of the heating rod at bivalent point	[kW$_{\mathrm{th}}$/kW$_{\mathrm{th}}$ specific heat load]	0.36
Contribution margin of HPs in bivalent monoenergetic operation	[%]	0.98

Equipment costs from list prices do not reflect the equipment prices in offers of installation firms. On the one hand, installation firms add a contribution margin to equipment costs to cover their fixed costs. On the other hand, manufacturers often grant a discount to installation firms. Both contribution margin and discounts are not transparent. We are looking for a contribution that calibrates our modeled investment costs well against offers for the installation of heat pumps and gas boilers. We find a contribution margin of 25%.

Figure C.1 shows the investment cost structure of the heating systems in different settlement types. The cost structure in the rural and village settlement types is identical because both settlements have the same building type, and the simultaneity factor is very similar. Across settlements, we see that investment costs decrease from the rural to the city settlement type. For decentralized heating, this decrease is due to scale effects caused by larger buildings. For centralized heating technologies, the decrease is caused by higher simultaneity factors. Across all technologies, installation costs and the contribution margin

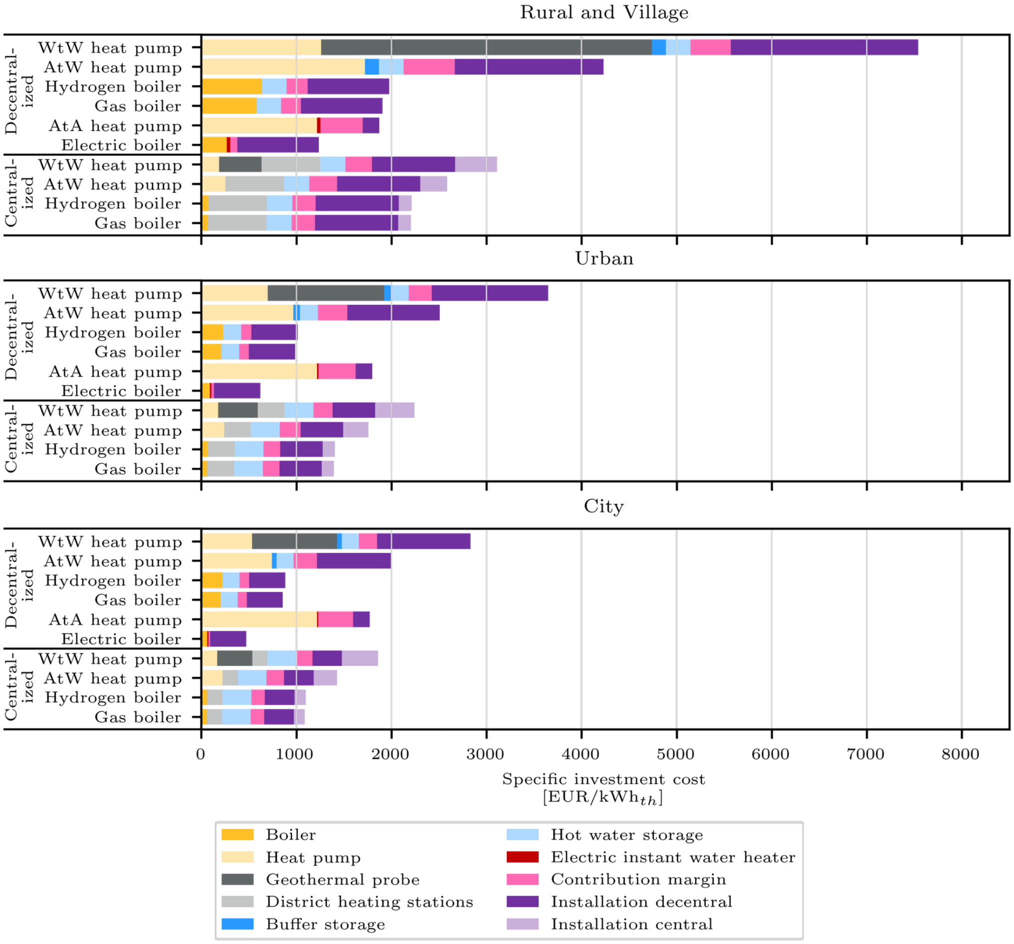
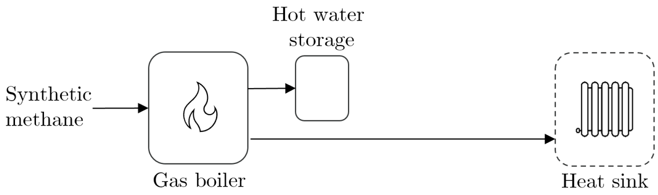
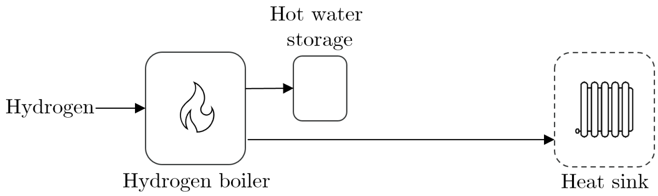


Figure C.1.: Structure of the specific investment costs of different heating systems by settlement type for buildings with a maximal supply temperature of 50°C account for around half of the investment costs. In centralized heating, the majority of the installation costs are for the decentralized district heating stations and hot water storages. In decentralized heating, the heat generator most of the equipment costs. In centralized heating, the centralized heat generator accounts for less than half of the equipment costs. Decentralized equipment like district heating stations and hot water storages make up the remainder of the equipment costs.

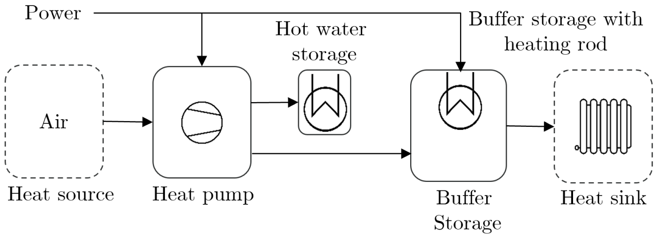
C.4. Heating systems



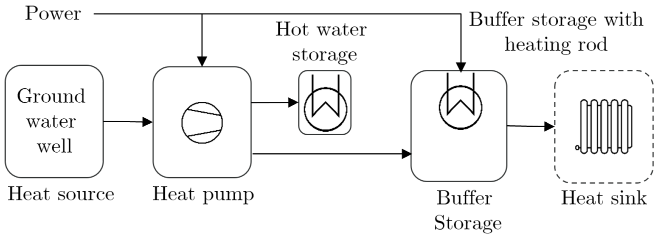
(a) Gas boiler decentral



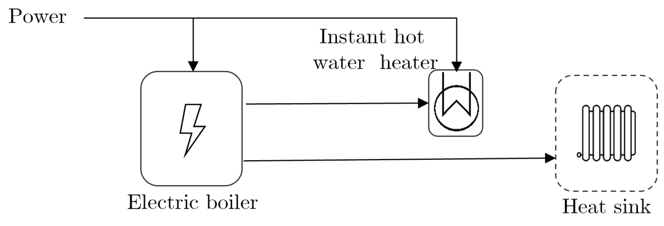
(b) Hydrogen boiler decentral



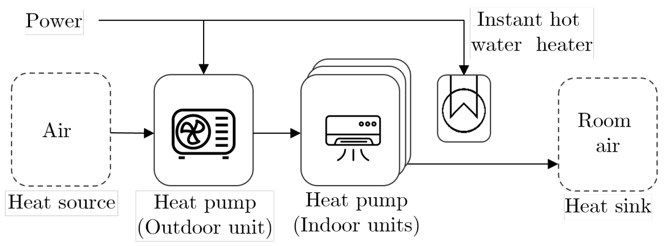
(c) AtW heat pump decentral



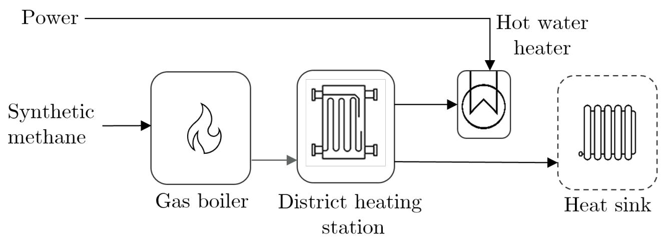
(d) WtW heat pump decentral



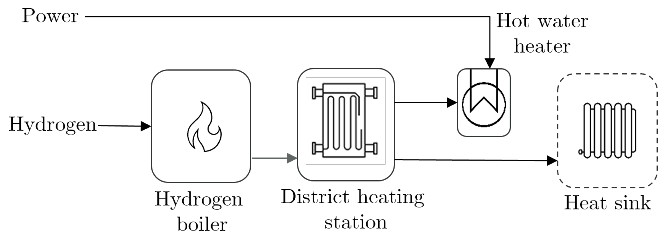
(e) Electric boiler decentral



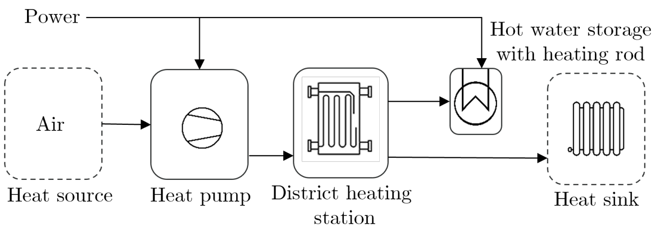
(f) AtA heat pump decentral



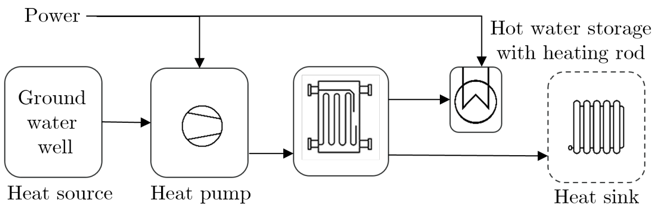
(g) Gas boiler central



(h) Hydrogen boiler central



(i) AtW heat pump central



(j) WtW heat pump central

Figure C.2.: Energy flow charts and major equipment units of the heating systems

C.5. Estimation of heat losses

The heat loss of heating grids depends on the temperature of the grid and the settlement type. The AGFW (2001) provides typical heat losses per settlement type (see Figure C.3). Due to a lack of information, we assume that these heat losses refer to the average heating grid temperature in Germany. We estimate the grid length weighted average temperature of heating grids in Germany based on data by Agora Energiewende and Fraunhofer IEG (2023). Further, we assume that heat loss is caused by conduction to the ground with a ground temperature of 10°C and a temperature spread between supply and return of 20 K. We estimate the heat losses for different grid supply temperatures based on these assumptions. Table C.3 shows the estimated heat losses. Due to a lack of data, we extrapolate the heat loss for the rural settlement type from existing data according to Figure C.3

Table C.3.: Heat losses of a heating grid depending on it's supply temperature and the settlement type

Supply temperature	Rural	Village	Urban	City
40°C	14 %	6 %	3 %	1 %
60°C	24 %	10 %	4 %	2 %
80°C	34 %	14 %	6 %	3 %

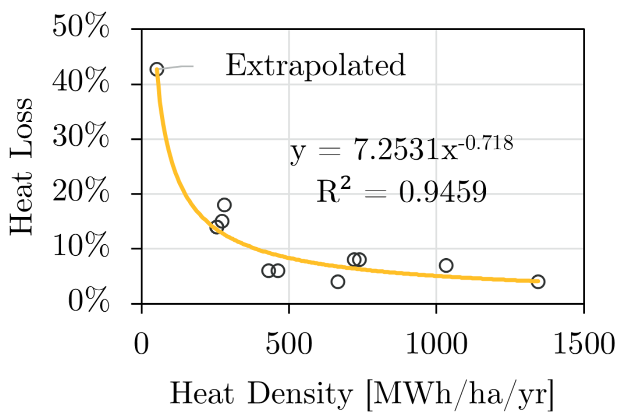


Figure C.3.: Extrapolation of heat loss over heat density for the rural settlement

C.6. Hydrogen and SNG price estimation

We use the following scenarios from EWI (2024b) to generate data on import costs for hydrogen and SNG:

- 2025, baseline cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, CO_2 from DAC
- 2050, baseline cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, CO_2 from DAC
- 2025, optimistic cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, CO_2 from DAC
- 2050, optimistic cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, CO_2 from DAC
- 2025, baseline cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, biogenic CO_2
- 2050, baseline cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, biogenic CO_2
- 2025, optimistic cost scenario, high cost new hydrogen pipelines, greenfield gas pipelines, biogenic CO_2
- 2050, optimistic cost scenario retrofitted hydrogen pipelines, brownfield gas pipelines, biogenic CO_2

We assume that biogenic CO_2 is available for 50 USD/t. In addition to the import cost, we add a markup for storage costs of 5.2 EUR/MWh for hydrogen and 3.3 EUR/MWh for SNG. The storage costs are derived from model results by Keutz and Kopp (2024), who calculate hydrogen and natural gas storage requirements for climate neutrality scenarios and different weather years. We levelize the storage costs by dividing them by the annual demand.

C.7. Parametrization of grid fees

Equation C.4 specifies the calculation of the baseline grid fees for gas, hydrogen, and electricity grids depending on the energy density of the settlement type by:

$$f(x) = \Big(1 + \frac{(1+a)\overline{gf} - \overline{dc}}{\overline{dc}}\Big) b x^c \tag{C.4}$$

, where a is the baseline assumption of future increase of grid fees compared to 2023 levels, $\overline{gf}$ are the average grid fees for households (decentralized heating) or commercial (centralized heating) of 2023, $\overline{dc}$ are the average gas or power distribution cost of the German distribution system operators, b and c are parameters of a power function fitted to the distribution cost over energy density data of the German distribution system operators. Table C.4 shows the parameters for the calculation of the grid fees according to Equation C.4

Table C.4.: Calculation of scaled grid fee functions

$f(x)$ $[\frac{\text{ct}}{\text{kWh}}]$	x $[\frac{\text{MWh}}{\text{ha·yr}}]$	$\overline{gf}$ $[\frac{\text{ct}}{\text{kWh}}]$	$\overline{dc}$ $[\frac{\text{ct}}{\text{kWh}}]$	a [-]	b [-]	c [-]
Gas grid fees decentralized	Gas density	1.89	0.956	0.2	4.7884	-0.307
Gas grid fees centralized	Gas density	1.48	0.956	0.3	4.7884	-0.307
Hydrogen grid fees decentralized	Gas density	1.89	0.956	0.8	$\frac{4.7884}{0.8}$	-0.307
Hydrogen grid fees centralized	Gas density	1.48	0.956	0.9	$\frac{4.7884}{0.8}$	-0.307
Power grid fees decentralized	Power density	9.35	3.275	1.68	11.193	-0.268
Power grid fees centralized	Power density	7.42	3.275	1.34	11.193	-0.268

C.8. Calculation of the seasonal performance factor

We estimate the seasonal performance factor SPF_3 of AtW and WtW heat pumps using data-based functions. The SPF_3 includes the heat pump, the heating rod, pumps, and ventilators as electrical consumers. Lämmle et al. (2022) provide a functional relationship between the SPF_3 and the mean heat pump temperature based on field measurements in Germany. They also provide the mean heat pump temperature for nominal supply and return temperatures. Based on this data, we derive a linear relationship between the SPF_3 and the nominal supply temperature for the supply temperatures between 30°C and 70°C. We also derive an uncertainty range based on the variance in the data. For centralized heating with heat pumps, we assume that the domestic hot water is heated via the heating grid if possible. We assume a temperature spread of 10 K between the heating grid and the supply temperature of the building. Suppose the domestic hot water temperature is higher than the temperature of the heating grid minus the temperature difference of 10 K. In that case, the remaining domestic hot water heating is done via a heating rod. The SPF_3 is the weighted average of the heat pump's SPF_3 and the heating rod's efficiency.
For AtA heat pumps, we calculate the SPF_3 for the reference climate in Germany. To that end, approximate the SPF_3 by the heat load weighted average COP. We use an hourly heat load time series from EWI (2025) and estimate the COP of AtA heat pumps based on Equation C.3.

C.9. Sensitivities in settlements with homogenous supply temperature

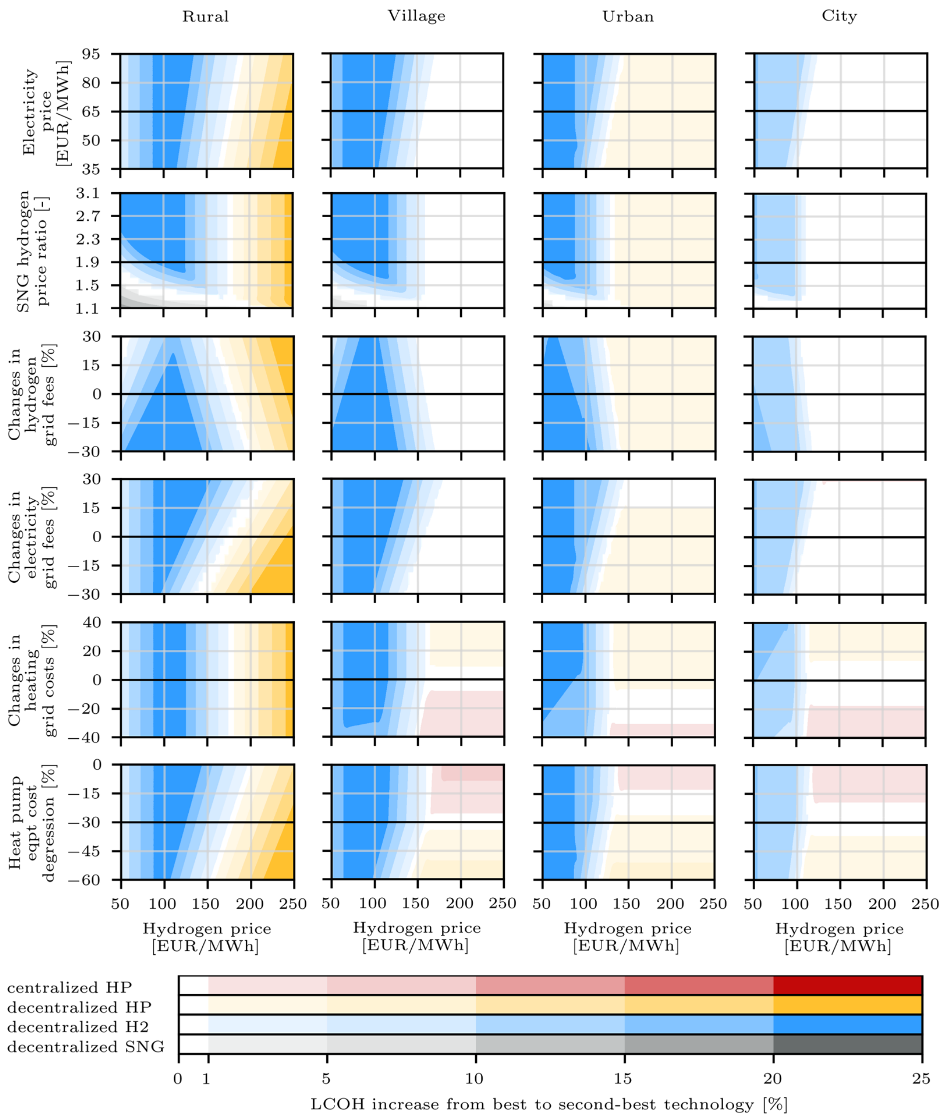


Figure C.4.: The impact of uncertain and heterogenous parameters on the cost-efficient heating technology in different settlement types for buildings with a supply temperature of 70°C. Colors indicate the cost-efficient technology. Color shades indicate the LCOH increase from the cost-efficient to the second-best technology. Black lines show the baseline assumption of each varied parameter.

D. Supplementary Material for Chapter 5

D.1. Validation of the Archetype Buildings

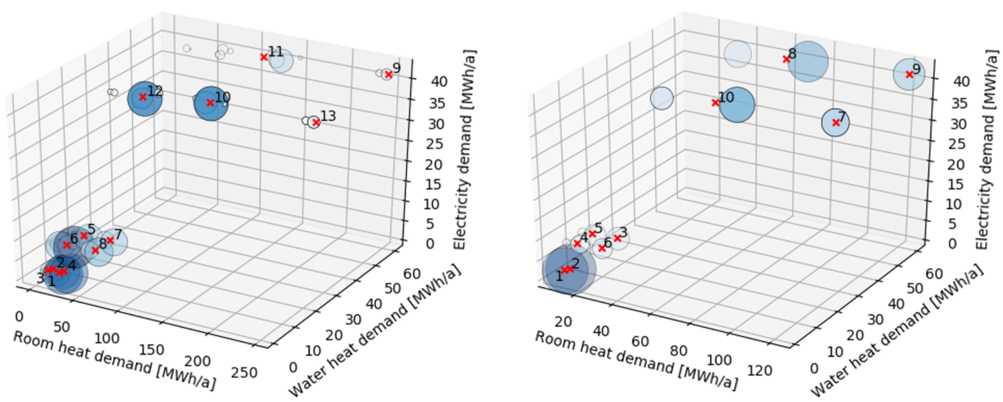


Figure D.1.: Representative demand combinations (red) and demand combinations from Scharf et al. (2021) (blue). Left: 13 combinations representing the existing building stock. Right: 10 combinations representing buildings constructed after 2011, used as a basis for defining newly constructed buildings. The size and shade of the blue marker represent the weight used in clustering, equal to the sum of heat and electricity demand.

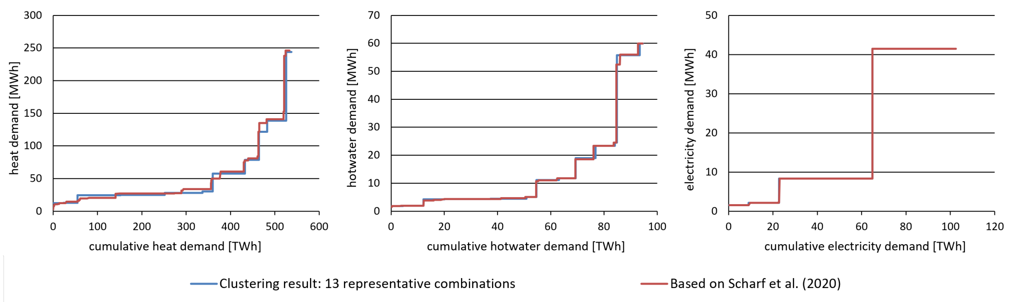


Figure D.2.: Cumulative demand values of the German building stock in 2019 compared between the database of Scharf et al. (2021) and our model.

D.2. Scenario Assumptions

D.2.1. Wholesale Electricity Price and Market Value

To project wholesale electricity prices through 2045, we use the energy system model DIMENSION, an optimization model for energy supply in Europe based on demand projections in end-use sectors. The model was initially published in Richter (2011) and has been used and extended in various studies (e.g., Bertsch et al. (2016), Peter (2019), Helgeson and Peter (2020) and Bucksteeg et al. (2022)). We apply the model version and assumptions (EWI, 2021). Additionally, fuel price assumptions are adjusted according to (Mendelevitch et al., 2022) to align with the COMODO model assumptions. Table D.1 shows the projected wholesale electricity prices and assumed PV system value factors, which form the basis for PV market remuneration in the COMODO.

Table D.1.: Assumed wholesale electricity prices and value factors of PV systems. PV value factors are based on Hirth (2013).

	2025	2030	2035	2040	2045
Wholesale electricity price [EUR/kWh]	0.083	0.044	0.056	0.057	0.064
Value factor PV	0.8	0.7	0.6	0.5	0.4

D.2.2. Existing PV Systems and Feed-In Tariffs

Based on Bundesnetzagentur (2023c), the construction of PV systems over the last 20 years is categorized into five-year periods, each represented by a mid-year (2005, 2010, 2015, 2020). A distinction is made between systems in SFH (< 10 kW) and MFH (10-40 kW). Table D.2 shows the share of each period in total PV system installations. In the model, archetype buildings are allocated according to these shares, assuming a 20-year lifetime for PV systems, starting from the average year of each period.

In both scenarios, existing PV systems receive feed-in tariffs based on historical support schemes. Feed-in tariffs by construction year are weighted by the number of systems built in each period to calculate the average tariff for each period. The resulting feed-in tariffs in the model are shown in Table D.2.

D.3. Sensitivity Analysis

To test the robustness of our results against electricity price increases, a sensitivity analysis was conducted using an alternative, strictly increasing electricity price path shown in Table D.3. All other parameters remain consistent with the main analysis.

Heating technology in 2019	Building type	System failure year	gCO_2 per kWh heat and hot water demand						Share of buildings with add. technologies		
			2019	2025	2030	2035	2040	2045	PV	Battery	Solar thermal
Oil boiler	SFH	2025	250	0	0	0	0	7	57%	17%	36%
Oil boiler	SFH	2030	250	245	0	0	0	0	57%	17%	36%
Oil boiler	SFH	2035	250	245	229	0	0	0	57%	17%	36%
Oil boiler	SFH	2040	250	242	229	226	0	0	57%	17%	36%
Oil boiler	SFH	2045	250	245	227	226	217	7	57%	27%	36%
Oil boiler	sMFH	2025	256	0	0	0	0	0	55%	55%	79%
Oil boiler	sMFH	2030	256	218	0	0	0	0	55%	55%	79%
Oil boiler	sMFH	2035	256	218	226	0	0	0	55%	55%	79%
Oil boiler	sMFH	2040	256	218	226	222	0	0	55%	55%	79%
Oil boiler	sMFH	2045	256	218	225	222	219	0	55%	55%	79%
Oil boiler	lMFH	2025	260	4	4	4	4	67	26%	26%	100%
Oil boiler	lMFH	2030	260	197	39	39	39	39	26%	26%	100%
Oil boiler	lMFH	2035	260	197	197	39	39	39	26%	26%	100%
Oil boiler	lMFH	2040	260	197	197	197	67	67	26%	26%	100%
Oil boiler	lMFH	2045	260	197	197	197	197	67	26%	26%	100%
Gas boiler	SFH	2025	171	0	0	0	0	3	55%	33%	38%
Gas boiler	SFH	2030	171	112	0	0	0	0	55%	33%	38%
Gas boiler	SFH	2035	171	145	145	0	0	0	55%	33%	38%
Gas boiler	SFH	2040	171	145	144	144	6	6	55%	23%	38%
Gas boiler	SFH	2045	171	146	144	144	144	3	55%	27%	38%
Gas boiler	sMFH	2025/2030	181	0	0	0	0	0	53%	53%	75%
Gas boiler	sMFH	2035	181	67	70	0	0	0	53%	53%	75%
Gas boiler	sMFH	2040	181	121	125	125	0	0	53%	53%	75%
Gas boiler	sMFH	2045	181	138	143	143	143	0	53%	53%	75%
Gas boiler	lMFH	2025	194	4	4	4	4	68	21%	21%	100%
Gas boiler	lMFH	2030	194	6	4	4	4	68	21%	21%	100%
Gas boiler	lMFH	2035	194	12	12	12	12	68	21%	21%	100%
Gas boiler	lMFH	2040	194	49	48	48	28	68	21%	21%	100%
Gas boiler	lMFH	2045	194	78	78	78	150	68	21%	21%	100%
Gas single-story	sMFH	2025	207	55	58	58	58	76	57%	57%	0%
Gas single-story	sMFH	2030	207	124	66	66	65	72	57%	57%	0%
Gas single-story	sMFH	2035	207	193	193	70	70	70	57%	57%	0%
Gas single-story	sMFH	2040	207	193	195	195	72	70	57%	57%	0%
Gas single-story	sMFH	2045	207	193	193	192	192	76	57%	57%	0%
Gas single-story	lMFH	2025	206	56	52	52	48	72	18%	18%	82%
Gas single-story	lMFH	2030	206	202	69	69	65	65	18%	18%	82%
Gas single-story	lMFH	2035	206	202	198	70	67	67	18%	18%	82%
Gas single-story	lMFH	2040	206	202	198	198	69	69	18%	18%	82%
Gas single-story	lMFH	2045	206	202	198	198	194	72	18%	18%	82%
Gas heat pump	sMFH	2040	134	119	134	134	0	0	52%	52%	48%
Gas heat pump	sMFH	2045	134	119	134	134	134	0	52%	52%	48%
Elec. heat pump	SFH	2035-2045	0	0	0	0	0	0	100%	73%	0%
New build < 2035	SFH	-	-	0	0	0	0	0	100%	100%	3%
New build < 2035	sMFH	-	-	24	26	26	26	39	100%	100%	73%
New build < 2035	lMFH	-	-	0	0	0	0	29	100%	100%	100%
New build ≥ 2035	SFH	-	-	-	-	0	0	0	100%	100%	3%
New build ≥ 2035	sMFH	-	-	-	-	37	37	37	100%	100%	73%
New build ≥ 2035	lMFH	-	-	-	-	19	19	19	100%	100%	100%

Figure D.3.: Investment and timing and CO_2 footprint (electricity price sensitivity). Note: Colors represent installed primary heating systems by year and building category, with red for gas, gray for oil, and green for electric heat pumps. Mixed colors indicate the weighted number of buildings using each technology if choices vary. Numbers show average CO_2 intensity in g/kWh of heating. The right columns list the percentage of buildings with PV, batteries, and solar thermal installations in 2045 by category.

Table D.2.: Assumed share of existing PV systems and corresponding feed-in tariffs by construction year

	Share (%)		Feed-in tariff (ct/kWh)	
Construction year	SFH	MFH	SFH	MFH
2005	10.3	12.2	52.08	52.44
2010	29.2	53.5	33.52	34.39
2015	16.8	7.1	13.37	13.34
2020	43.7	27.2	8.5	7.59

Table D.3.: Electricity prices in the main scenario and sensitivity analysis (ct/kWh)

	2020	2025	2030	2035	2040	2045
Main	32.2	30.5	26.6	28.4	28.9	30.0
Sensitivity	32.2	30.5	32.6	36.4	38.8	42.0

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