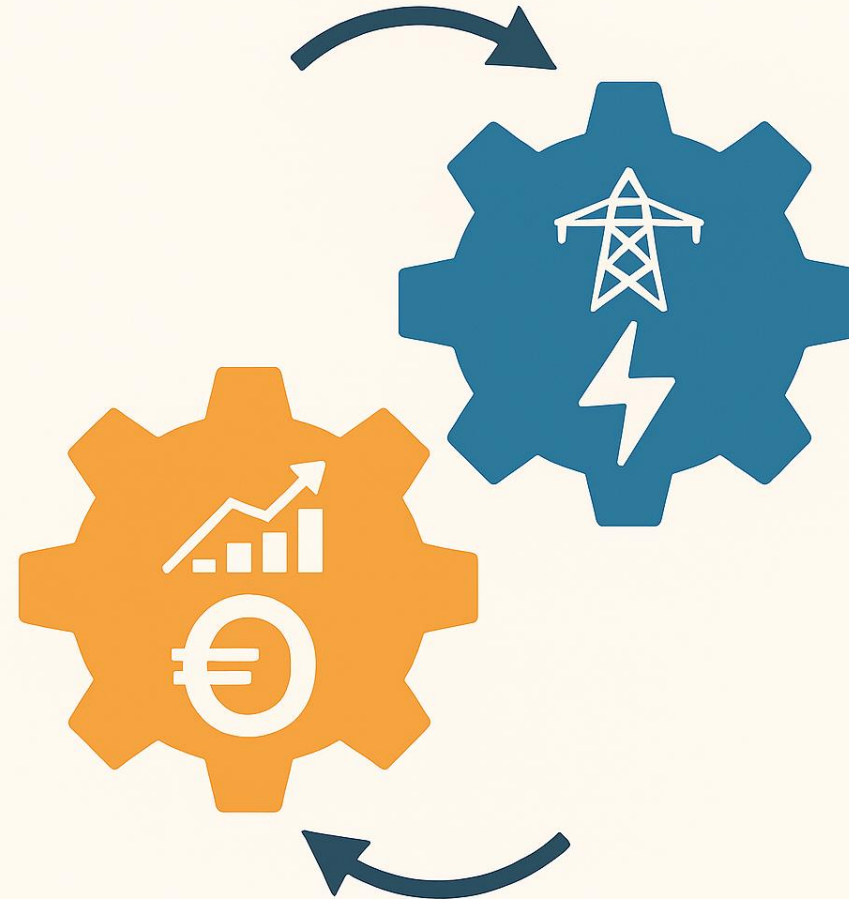


Impact of Spatio-Temporal Network Fees on Market Results and Redispatch Requirements

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ABM4Energy, 30.03.2026

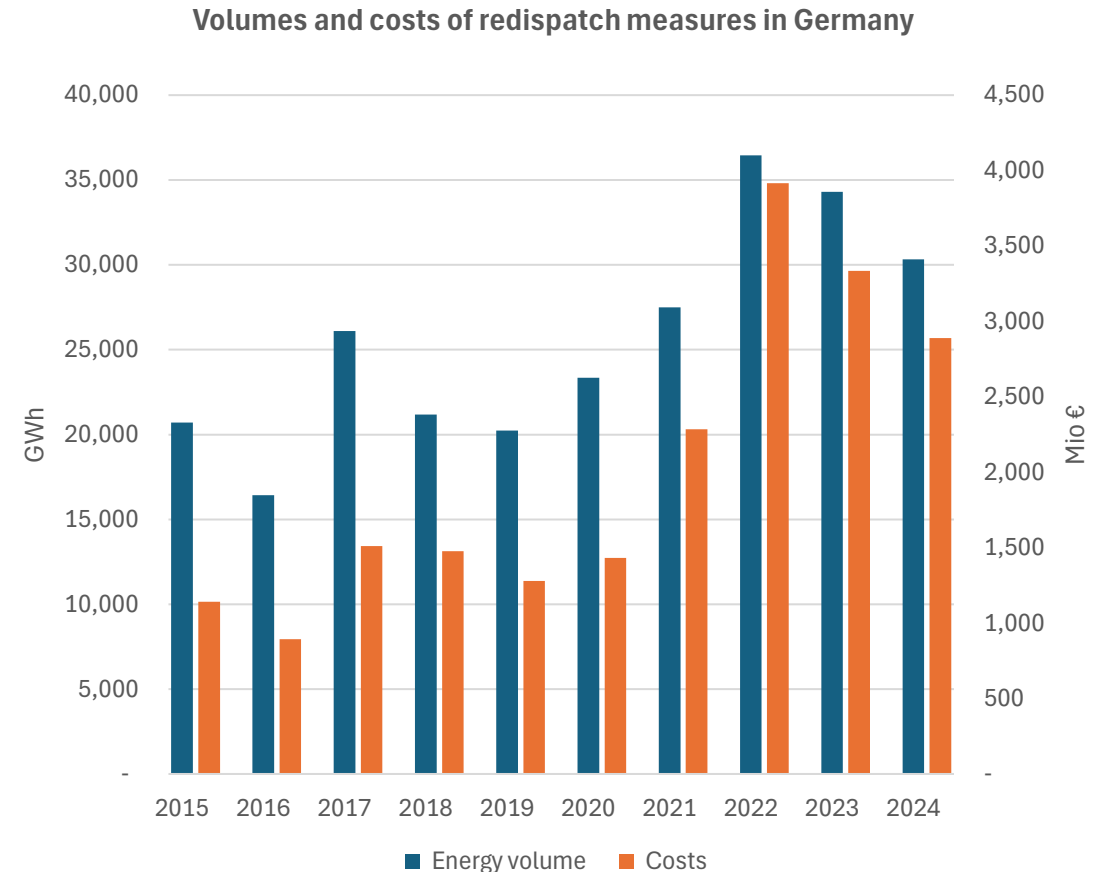


Agenda

- 1. Motivation**
- 2. Methodology**
- 3. Results from a case study**
- 4. Conclusion**

Motivation

- Redispatch costs are likely to rise due to increased RES generation
- Grid expansion is expensive and time consuming
- Internalizing grid constraints in market operation could help in reducing grid related congestion and redispatch costs
- Idea: Spatially and temporally differentiated incentives for producers in form of dynamic grid fees
- Research questions:
 - How to determine grid fees in advance of market clearing and redispatch calculation?
 - What are the impacts of the fees on market and grid operation?

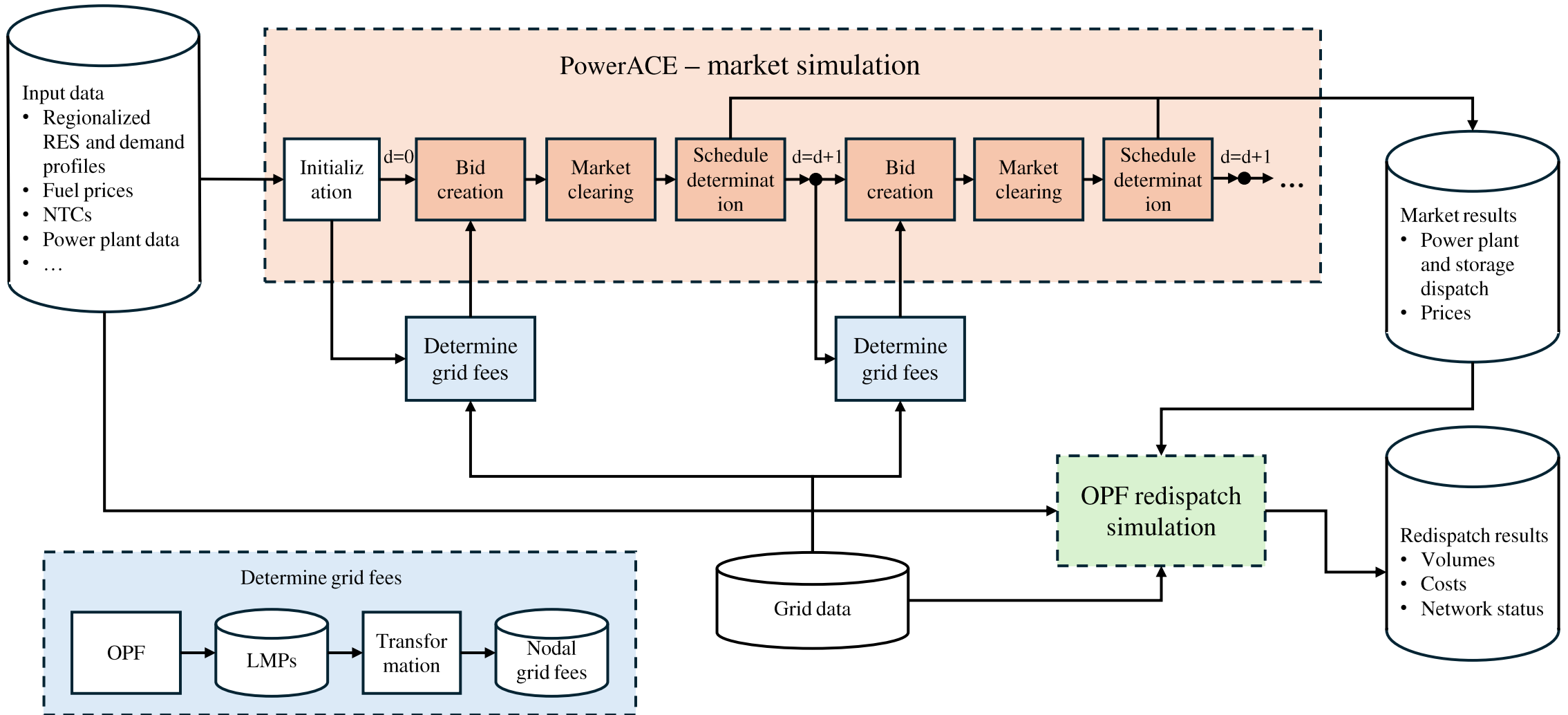


[1]

Network charges

- Currently, in Germany only consumers pay grid fees to finance the power grid; producers do not
 - Proposal by the Federal Network Agency (AgNes [2]): Include producers, distinguishing between financing function and incentive function
-
- Financing function
 - Contribution to coverage of grid expansion costs
 - Capacity charges for producers based on grid connection capacity
 - Incentive function
 - Promotion of grid friendly behavior
 - Volume-based
 - Temporally and spatially differentiated with sign-consistent design
 - Depending on the effect of power injection (alleviating or exacerbating congestion)

Methodology – Overview



Methodology – Agent Based Market Simulation Model PowerACE

Characteristics

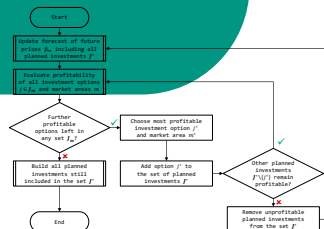
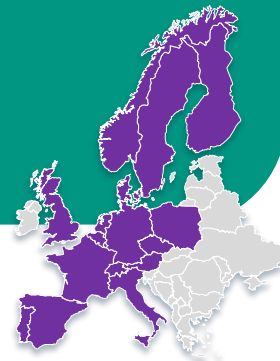
- Hourly simulation of the day-ahead market (8760 h/a)
- Combined daily market clearing
- Yearly investment decisions
- Time horizon until 2050
- No perfect foresight, i.e., investment decisions
- Cross border effects

Input Data

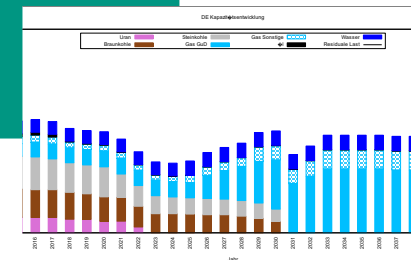
- Fuel and CO₂ prices
- Detailed power plant data with techno-economical parameters (e.g., efficiency, ...)
- Hourly RES profiles and demand profiles
- Trading capacities between market areas

Model results

- From market simulation, e.g.,
- Power plant dispatch
 - Spot market prices and volumes
 - CO₂ - Emissions
- From investment evaluation, e.g.
- Capacity development
 - Investment decisions



Source: Genoese (2010),
Fraunholz (2021),
Zimmermann & Keles (2023)



Methodology – Optimal Power Flow Model

- Aim: find the (cost-) optimal operating state of an electrical energy system considering network constraints
- AC formulation

$$P_{i,t}^{\text{in}} - P_{i,t}^{\text{out}} - V_{i,t} \sum_{k \in I, k \neq i} V_{k,t} (G_{ik} \cos(\theta_{i,t} - \theta_{k,t}) + B_{ik} \sin(\theta_{i,t} - \theta_{k,t})) - V_{i,t}^2 G_{ii} = 0,$$

$$Q_{i,t}^{\text{in}} - Q_{i,t}^{\text{out}} - V_{i,t} \sum_{k \in I, k \neq i} V_{k,t} (G_{ik} \sin(\theta_{i,t} - \theta_{k,t}) - B_{ik} \cos(\theta_{i,t} - \theta_{k,t})) + V_{i,t}^2 B_{ii} = 0,$$

- Dispatch and redispatch simulations possible
- Locational Marginal Prices (LMPs)
 - Direct outcome of the OPF solution (result for the dual variable of the nodal power balance equation)
 - Dispatching cost variation for a unit increment of demand at a bus [€/MWh]

Methodology – Determination of Dynamic Network Charges

- Median based allocation of temporally and spatially dynamic tariffs
- Parameters: τ and S_{max}

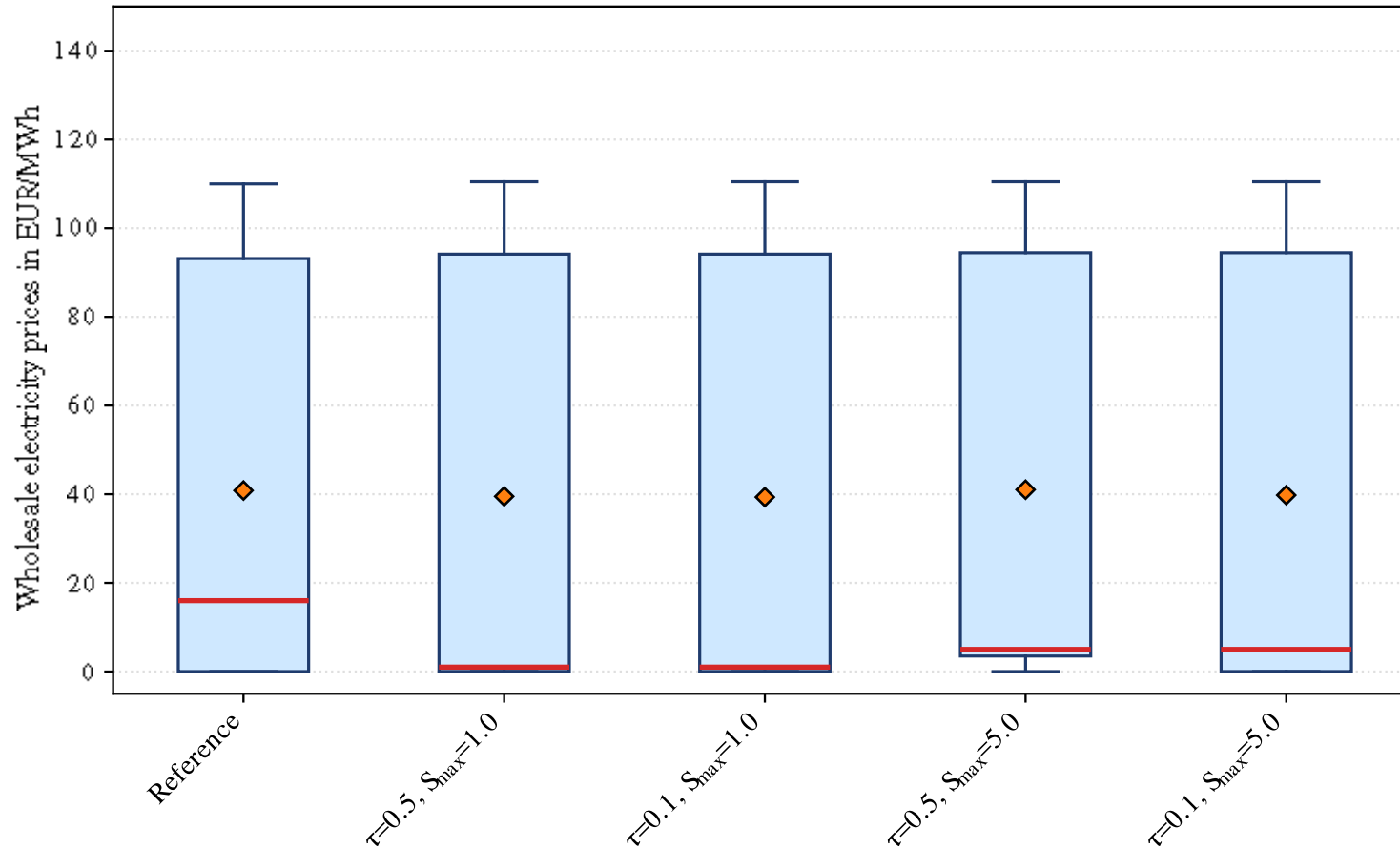
For $t = 0 \dots 24$:

1. Order LMPs for current t based on their values and determine the median
2. Determine the sign of the network charges
 - a. Nodes with LMP > median: negative sign
 - b. Nodes with LMP < median: positive sign
3. Determine the magnitude of the network charges
 - a. Only nodes within the τ -percentile (lowest and highest LMPs) receive a charge $\neq 0$, all others get 0
 - b. Nodes with non-zero charges are grouped into ten LMP-based tiers. The group with the most extreme LMPs receives the maximum magnitude S_{max} , which is reduced by 10% for each successive tier
4. The producers are assigned the network charge of the node they are connected to as additional variable costs

Case Study

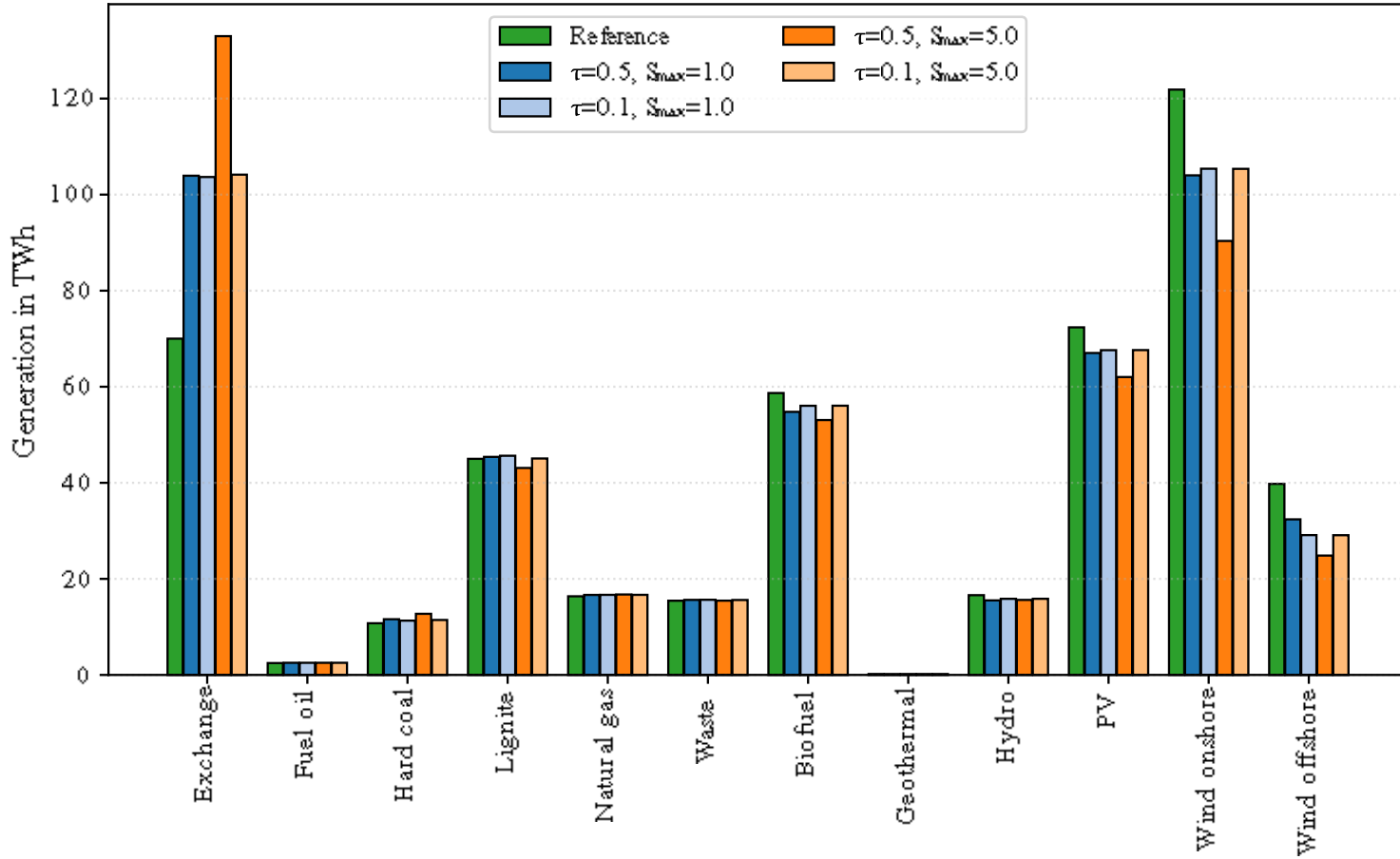
- Scenario based on the year 2025
- Temporal coverage: 1 year with hourly resolution
- Spatial coverage:
 - Market simulation: Germany and neighboring countries (DE-LU, AT, BE, CH, CZ, DK, FR, NL, PL)
 - Redispatch simulation: DE-LU with fixed exchange flows from market simulation
 - OPF for grid fee determination: DE-LU and neighboring countries (neighbors simplified without grid constraints)
- Grid data: DE-LU transmission grid (220kV and above)

Results – Market Prices



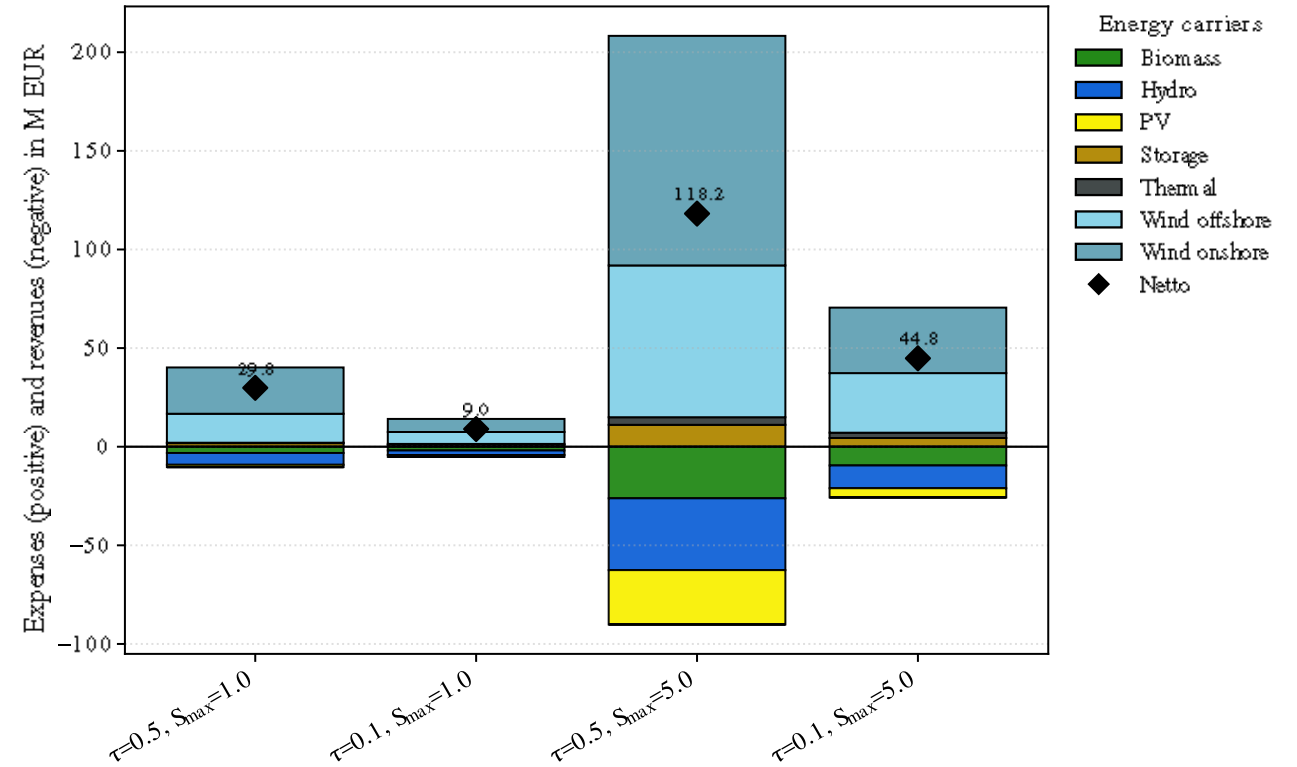
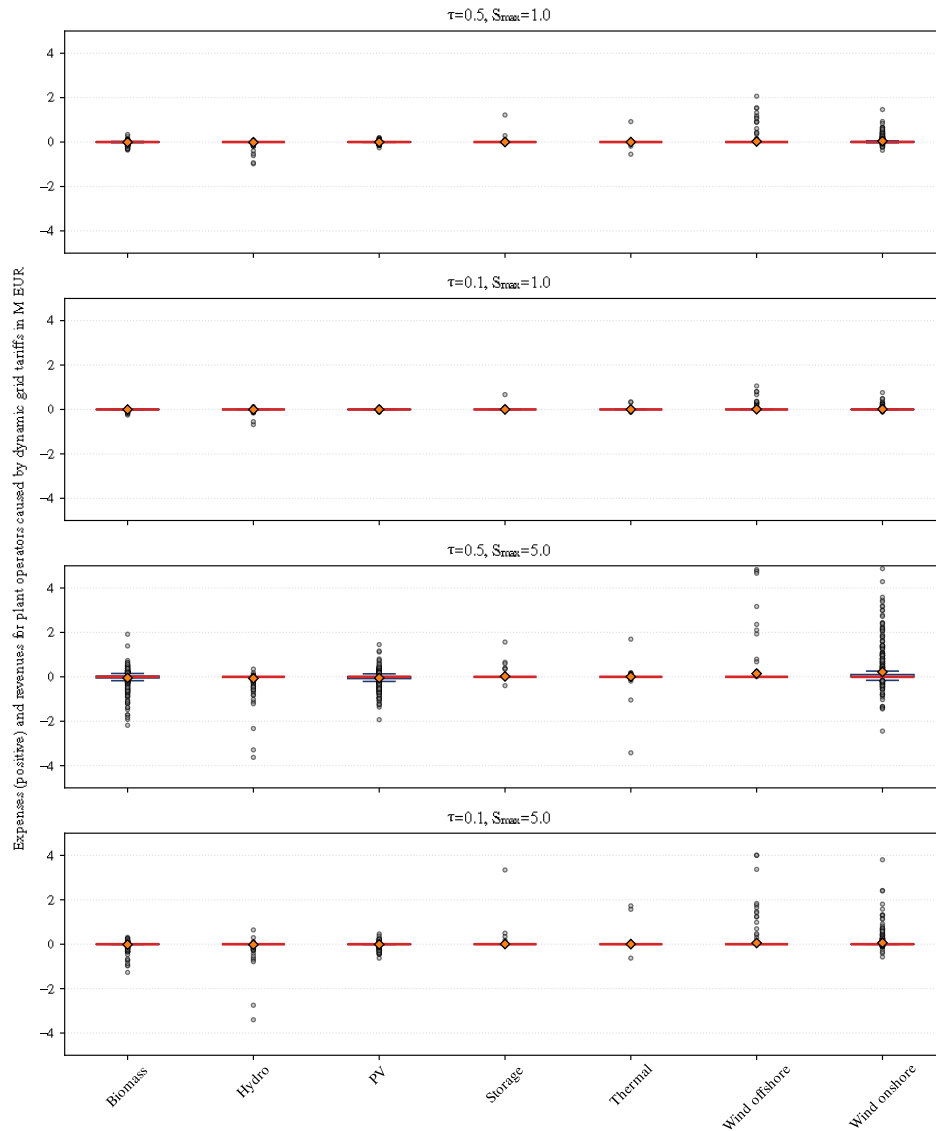
- Only small differences in wholesale prices across all scenarios
- Average price is +-1€/MWh
- Differences in median are due to jumps in the price duration curve, which are shifted by a few hours

Results – Market Dispatch

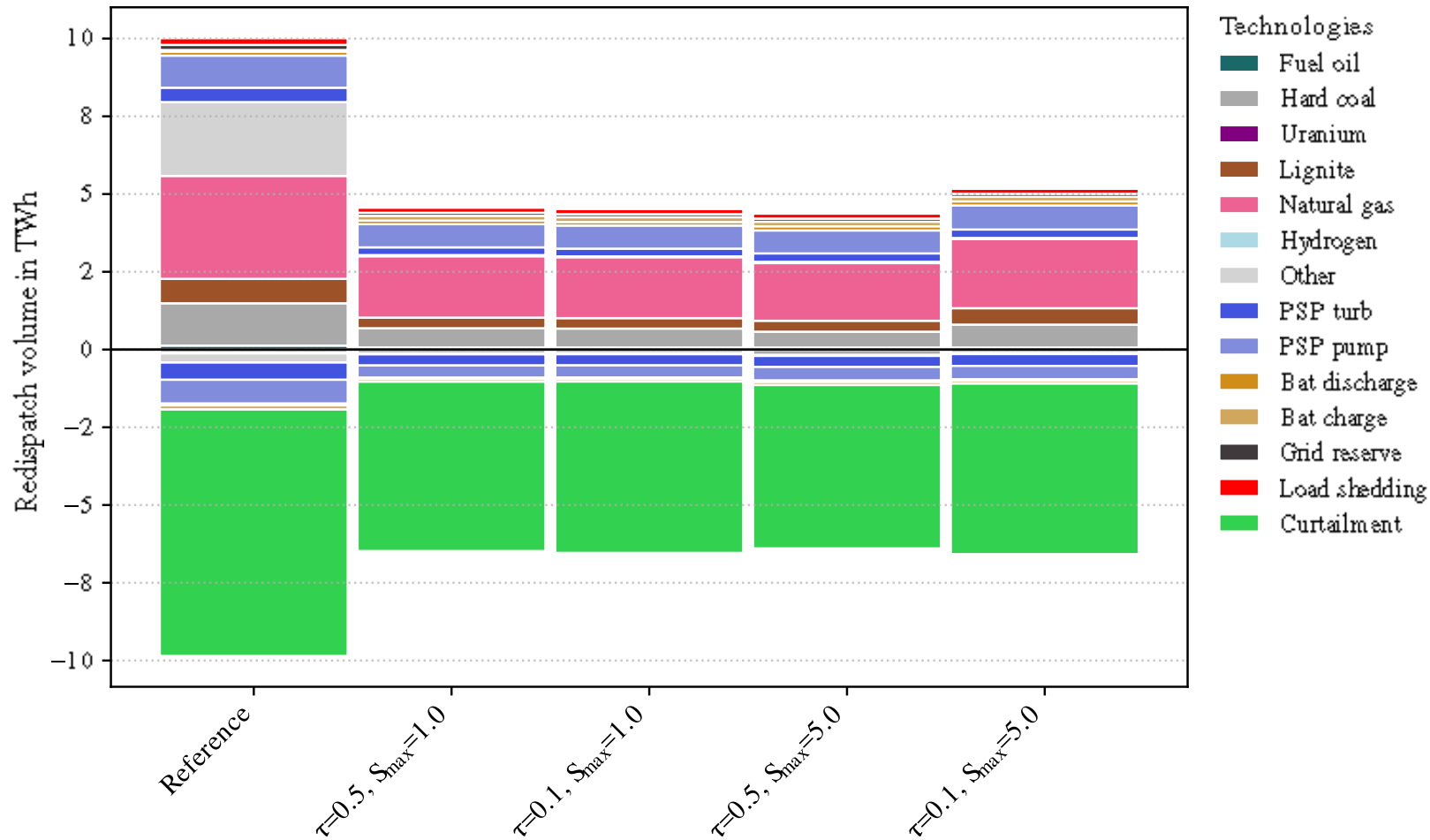


- Main differences to reference case:
 - Higher net imports
 - Lower domestic RES generation

Results – Additional Expenses and Revenues

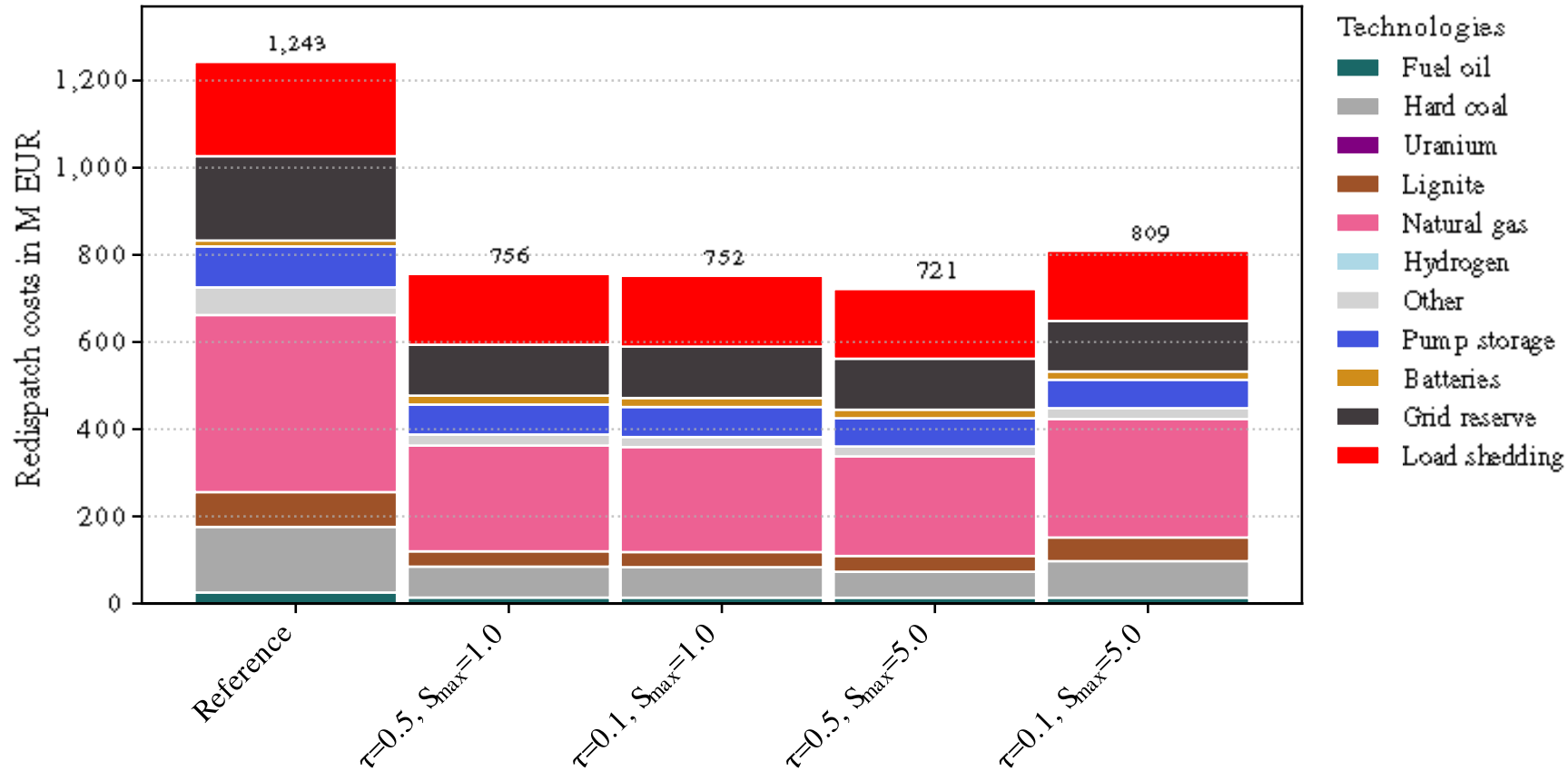


Results – Redispatch Volumes



- Significant reduction in redispatch volumes
- Mainly caused by less (+30%) grid related RES curtailment

Results – Redispatch Costs

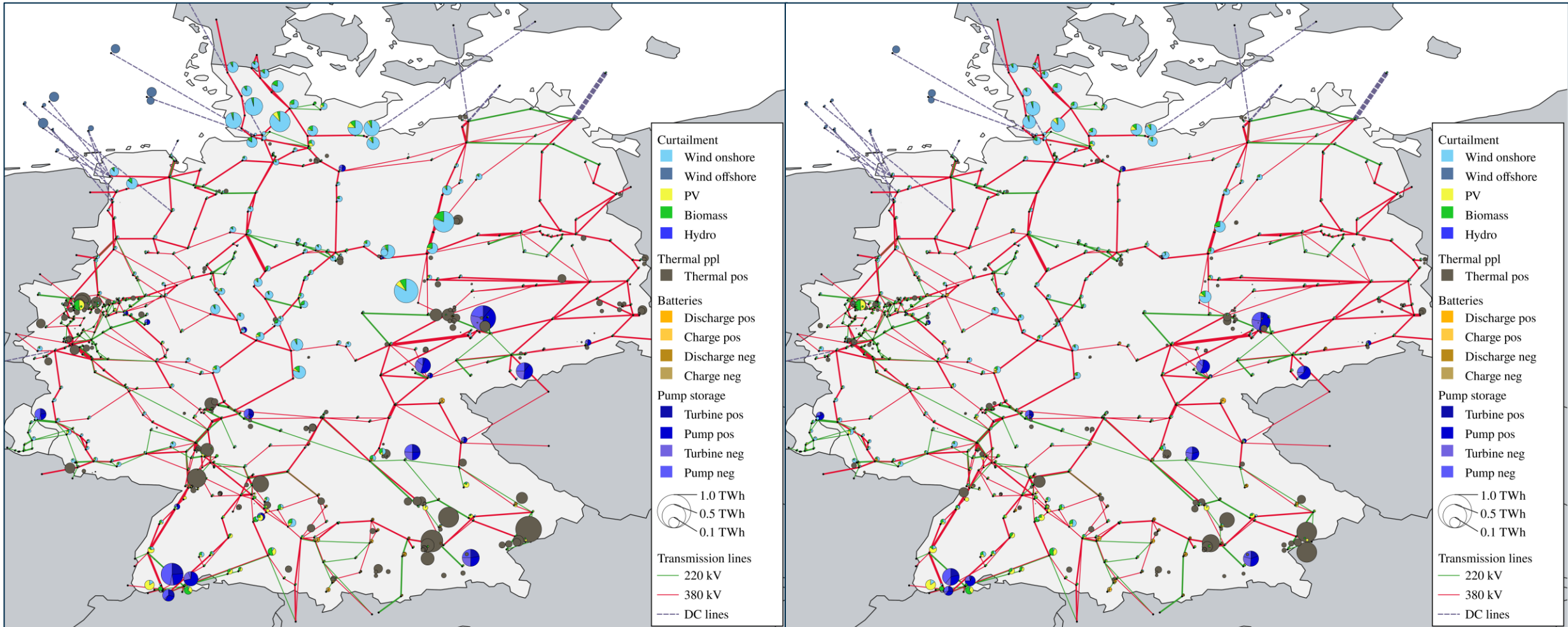


- ~ 40% cost reduction could be achieved
- Mainly due to less positive redispatch measures by thermal power plants

Results – Redispatch Distribution

Reference case

$\tau = 0.1, S_{max} = 1.0$



Critical Appraisal

- Promising results with redispatch cost reduction of 40% and only small impacts on the wholesale market
- Successful coupling of agent-based market model and AC-OPF transmission grid model

But:

- Only one scenario for one year was simulated
 - Simulations for future years and multiple scenarios
- Limiting the geographic scope of dynamic grid fees on Germany leads to substitution of domestic generation with imports
 - Expand the application of dynamic network charges to additional European countries
- Marginal bidding strategies for all market participants
 - Include more sophisticated bidding strategies, especially for RES this could make huge differences
- The resulting prices are generally too low compared to historic values, which suggests that the impact of dynamic network charges is being overestimated
 - Further assessment needed

References

[1] Bundesnetzagentur | SMARD, “The development of congestion management.” 2025. [Online]. Available: <https://www.smard.de/page/en/topic-article/212250/217910/the-development-of-congestion-management>

[2] Bundesnetzagentur, “Einspeiseentgelte: Orientierungspunkte der BNetzA - Festlegungsverfahren AgNes,” Feb. 2026, [Online]. Available: https://www.bundesnetzagentur.de/DE/Beschlusskammern/GBK/GBK_Termine/Downloads/2026/02_2026/20.02./AgNes_Orientierungspunkte_Einspeiser.pdf?__blob=publicationFile&v=3

