Ritter, David; Heinemann, Christoph; Bauknecht, Dierk; Winger, Christian; Flachsbarth, Franziska

Preprint

Model-based evaluation of decentralised electricity markets at different phases of the German energy transition

MODEL-BASED EVALUATION OF DECENTRALISED ELECTRICITY MARKETS AT DIFFERENT PHASES OF THE GERMAN ENERGY TRANSITION

David Ritter*[1], Christoph Heinemann[1], Dierk Bauknecht[1,2], Christian Winger[1] and Franziska Flachsbarth[1]

[1] Oeko-Institut e.V., Merzhauser Strasse 173, 79100 Freiburg, Germany

[2] Faculty of Environment and Natural Resources, University of Freiburg, Tennenbacherstrasse 4, 79106 Freiburg, Germany

* corresponding author (email: d.ritter@oeko.de; phone: +49 761 45295 280)

Keywords: decentralised markets, local energy markets, electricity market modelling, renewable integration, energy transition

1 Abstract

This paper investigates decentralised markets in the German electricity system, defined as markets in specific regions in which regional electricity demand is met primarily by regional generation and the remaining demand is met on a system-wide level in a second step. The research question is: What impact do the size of decentralised markets and the type of authorised participants have in different levels of the energy transition? The results show that the greatest effects from decentralised markets are caused by an increased usage of gas-fired power plants, as they are the major dispatchable generators in the future electricity system, resulting in significantly higher CO_2 emissions and electricity generation costs, but also higher local self-supply rates. With very high RES-E shares the results hardly differ between the reference case and decentralised market models. The size of decentralised markets has a lower impact than limited access for certain fuel types or generation capacity size. Although decentralised markets can reduce the load on the grid, the need for grid expansion does not decrease. Overall, we conclude that from a system perspective decentralised markets can lead to negative effects if they are not regulated appropriately, especially during the transformation phase of the electricity system.

2 Introduction

The motivation for this paper is based on the current discussion about the decentralisation of the energy system (e.g. Bauknecht, Funcke, and Vogel 2020). The process of decentralisation includes small-scale technologies like, for example, PV panels and household batteries as well as to some extent a new distribution and localisation of power plants, as in the case of wind power (Wimmer 2014). However, decentralised markets are also discussed as a possible market that addresses the main challenges in the transformation of the energy system. These challenges are described later in this introduction. This paper analyses the effects of such decentralised markets, including different design options. It focuses on the German electricity system, which is why the literature used also focuses on the German or European electricity system.

How does the idea of decentralised markets differ from the general decentralisation of the energy system explained above? Scientific research concerning decentralised markets frequently focuses on the subsidiarity principle, i.e. the division of the energy system into geographically delimited cells that balance power generation and demand at local level before making use of higher grid levels (Bayer et al. 2019; Zuber and Grunow 2017; Brand et al. 2017). There are also system modelling studies that claim to model such a decentralised energy system or even a cellular system, but focus on the decentralised allocation or deployment of renewable energy sources within a certain state or region (Falkenberg et al. 2016). Other studies have their emphasis on the size of regions needed for covering the local electricity demand by using renewable electricity generation capacity, without looking at the operational side of meeting this demand in local markets (Tröndle, Pfenninger, and Lilliestam 2019). The focus is mainly on a 100% renewable system (Tröndle et al. 2020) and not on the current electricity system nor the transformation phase.

More specifically for decentralised markets the current research and political debate is based on the subsequent drivers (partly based on Canzler et al. 2016; Bauknecht, Funcke, and Vogel 2020), where, however, specific scientific literature is missing for several of these drivers:

- Reduction of overall system complexity, which might increase due to a high number of small-scale technologies such as PV systems within the system
- Participation and acceptability (Mengelkamp et al. 2019; Bauknecht, Funcke, and Vogel 2020)
- Local possibilities for action (politically but also in the form of business cases) (Bauknecht, Funcke, and Vogel 2020)
- Reduction of grid expansion due to local RES-E deployment (Timpe et al. 2018)
- Local economic drivers (self-supply and autarky) (Mengelkamp et al. 2018)
- The topic is further driven by research projects looking into the potential of blockchain technologies being used in local power markets or community power concepts (Mengelkamp et al. 2018). In addition, peer-to-peer trading which often relies on new digital solutions as well, focuses on direct trading between two individuals within an energy system (Löbbe et al. 2020).

Looking at these drivers for the scientific and political debate on decentralised markets based on grid issues, local energy costs and other issues, we have identified a research gap in the field of system-wide effects of decentralised markets. This research gap was also identified by Weinand, Scheller, and McKenna (2020) who analysed 123 publications on decentralised energy autonomy. We therefore study decentralised markets not from the perspective of local effects, but in terms of their effects on the overall power system. Within our scenario analysis, we focus on three major variations related to the market design and the overall system configuration respectively (size of regions, allowed participants within the decentralised market, RES-E share within the system).

The analysis is based on reviewing the following indicators that are derived from the model-based scenario analysis: CO_2 emissions of electricity generation; regional levels of self-supply with electricity; variable costs of electricity generation; grid congestion and grid expansion needs.

The paper investigates small-scale decentralised markets in the German electricity system. In our case decentralised markets are defined as regions in which regional electricity demand is met primarily by regional generators, irrespective of grid constraints. The research question is twofold. Firstly, how does the size of decentralised markets affect indicators like CO_2 emissions, variable generation costs or the need for transmission grid expansion. Secondly, which effects on these indicators can be observed if only power plants of a certain size or technology are allowed to take part in the decentralised markets.

The analysis focuses on a system perspective and does not include effects on individual market players. In addition, it focuses on the electricity system with only some interactions with the heating or mobility sectors. The modelling work looks at the effects within the bounds of a predefined scenario and for two scenario years. Dynamic effects such as a possible effect of decentralised markets on the overall deployment of RES-E technologies or storage systems is therefore not part of the analysis. The results are valid for the German electricity system and cannot necessarily be transferred to other countries or electricity systems with e.g. a weaker electricity grid or less interconnection to neighbouring countries.

3 Methodology

In this study, different configurations of decentralised electricity markets in the German electricity system were examined for two different upcoming transformation levels of the system. Transformation level A is characterised by a RES-E share in the German gross electricity demand of approx. 70% and transformation level B by approx. 97%.

3.1 Description of decentralised markets analysed

For this analysis decentralised markets are defined as markets for a defined spatial region that include generation, demand as well as storage and other flexibility options such as demand side management (DSM). The decentralised markets are modelled with a two-step subsidiarity approach (Timpe et al. 2018). In the first step, regional demand is covered by regional generation using storage and other flexibility options dispatched by a decentralised market. The remaining demand and still available generation capacities are then covered or made available respectively in the European internal market.

Two dimensions were varied for the configuration of the decentralised markets: the size of the markets and the type of authorised participants on the markets. For the size of the decentralised markets two configurations were implemented, for the authorised participants three configurations. The resulting six variants were modelled with transformation level A and B and compared with each other as well as with the reference case, a load coverage in a centralised market, according to current regulations (cf. Table 1).

Table 1: Overview of the examined cases

	Level A (≈70% RES-E share)							Level B (≈97% RES-E share)							
Size of dec. markets	Reference	20 regions			457 areas			Reference	20 regions			457 areas		
Authorised participants		All	< 20MW	Only RES-E	All	< 20MW	Only RES-E		All	< 20MW	Only RES-E	All	< 20MW	Only RES-E
Scenario names	Ref	All – Reg.	< 20 MW - Reg	RES-E – Reg.	All – Area	< 20 MW – Area	RES-E – Area	Ref	All – Reg.	< 20 MW - Reg	RES-E – Reg.	All – Area	< 20 MW – Area	RES-E – Area

In the first configuration of decentralised markets, the German electricity market is divided into 20 regions. The regions are based on a data set of the German transmission grid made available to Oeko-Institut by the German Federal Network Agency (Bundesnetzagentur, BNetzA) in 2015. The regions are a derivative of 18 regions (plus two offshore zones) that were cited in Dena Grid Study II (Kohler, Agricola, and Seidl 2010) and consider transmission grid areas, federal state borders and potential future grid bottlenecks. In the second configuration, the number of the decentralised markets is increased significantly to 457 areas. These areas are defined by the nodes of the transmission grid, which are the connecting points between transmission and distribution grid. The German market was divided by a voronoi decomposition in such a way that one transmission node is located in the centre of each of the 457 areas. In Appendix A, two maps showing the outline of the 20 regions and the 457 areas can be found.

With regard to authorised producers, in the first option considered all production units in the region respectively the area are authorised to participate in the decentralised markets and thereby contribute to the regional load coverage in modelling step 1. In the configuration "< 20 MW" all production units with an installed capacity below 20 MW, which is a typical threshold value for connecting facilities to the medium-voltage grid (Agricola et al. 2012), are part of the decentralised markets. In the variant "RES-E" only renewable energy units and flexibility options are allowed to participate in the decentralised market.

The examined configurations of decentralised markets were analysed with regard to the indicators CO_2 emissions, variable electricity generation costs and local self-supply. Since the largest effects occurred for transformation level A, an in-depth analysis of the electricity generation structure, the effects on the transmission grid and regional differences in electricity prices for this transformation level is described subsequently.

3.2 Data and model description

The input data for generation capacities installed, electricity and heat demand, flexibility options as well as fuel and CO_2 prices for Germany is mainly based on Klimaschutzszenario 95 from Repenning et al. (2015). For the present analysis of decentralised markets, some parameters were adjusted for a more decentralised generation structure. For example, parts of the renewable energy production from wind offshore was shifted to photovoltaic plants. A detailed description of the procedure can be found in Kühnbach et al. (2020). The scenario Reference B described in this paper was used for the present analysis. Input data for the neighbouring European countries is based on eHighway 2050 scenario 100% RES (Andersky, Sanchis, and Betraoui 2016) with some minor adaptation that is described in Ritter et al. (2019) for the so-called ambitious scenario. The main input data for Germany can be found in Appendix A. All input data is made available in the data base Zenodo (an overview is given in Appendix A).

Modelling was carried out using Oeko-Institut's PowerFlex Grid EU electricity market model (Ritter et al. 2019; Koch et al. 2018). The model calculates the cost optimal dispatch of power plants, storage facilities and flexible electricity consumers in order to meet the demand for electricity in the integrated European electricity market. All ENTSO-E member states besides Cyprus and Iceland are considered in the model. Generally, in PowerFlex countries are modelled as uniform market areas without price zones or grid constraints. For the examination discussed in this paper the German electricity market was split into several decentralised markets (cf. chapter 3.1). The exchange between countries is implemented as a transport model, where exchange is limited by net transfer capacities (NTC).

Investment decisions are not part of the model. The development of generation units is hence a model input. The power plant fleet consists of dispatchable units and producers with a predefined generation profile. For Germany, dispatchable units above 100 MW are implemented as individual units, while smaller plants are aggregated. In other countries, the power plant fleet is implemented in aggregated vintage classes. Annual generation of volatile renewable technologies wind onshore, wind offshore, solar energy and run-of-river is used to scale historical generation profiles in an hourly resolution for the year 2016. This renewable production can be curtailed within the model if supply exceeds demand. Some power plants that do not respond to market signals are implemented with constant generation as so-called must-run units (e.g. mine gas or blast furnace gas plants).

Electricity generation from combined heat and power plants also depends on current heat demand, which, despite the heat storage considered, reduces their flexibility to react to electricity market needs. The demand profiles consist of historical profiles from 2016 and generic profiles for upcoming electricity applications such as for electric vehicles. Parts of the electricity consumption are implemented as demand respond options that can postpone their demand for some hours. These applications include parts of industrial demand, electric vehicles, and electric heat generation. Hydrogen demand is provided as a model input, and the model can determine the time of generation in a market-optimised manner. Beside these demand flexibility options and the dispatchable units, battery storage and pumped hydro storage are considered as flexibility options. In this study, the flexibility options described were only considered for the German electricity market. The amount of the flexibility options considered is shown in Appendix A.

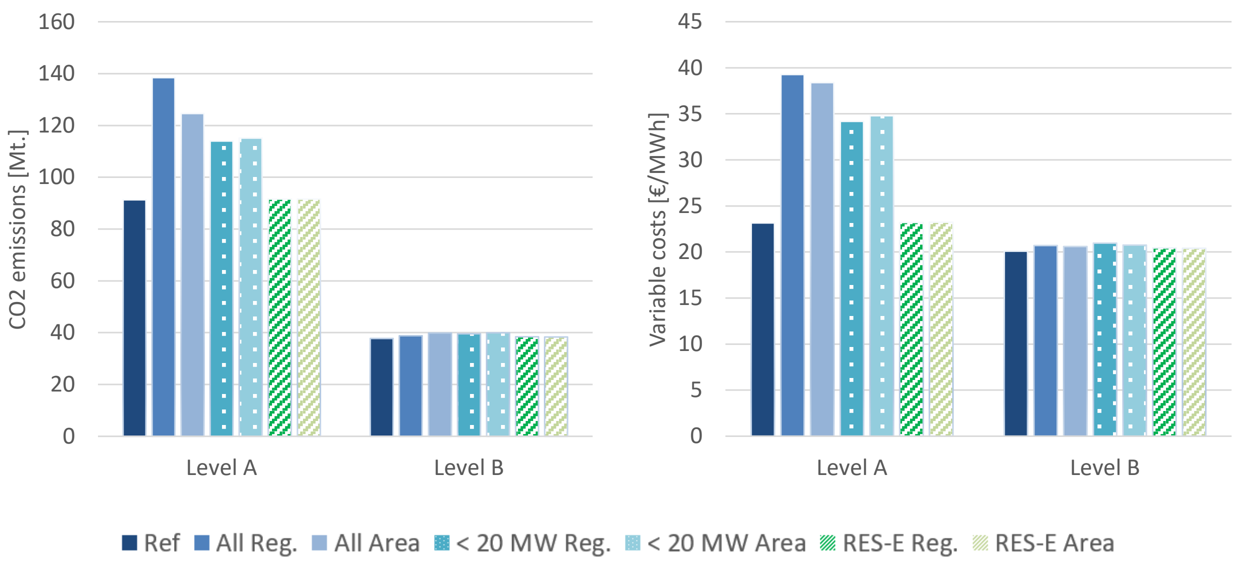
In order to achieve the ideal result from a market perspective, no grid constraints are considered in the market modelling. Based on the market modelling results, the congestion and the need for expansion of the German transmission grid were calculated. To carry out the grid analyses, the electricity market modelling must be performed with regionally resolved input data. The regionalisation parameters applied for this purpose are given in Appendix A. For foreign areas, no grid evaluations are carried out. The grid optimisation is an iterative process of adding or reinforcing line elements of the existing power grid from a pool of potential updates derived from current grid development plans. Instead of a perfect optimisation, it uses a heuristic approach to select modifications to find local minima of grid congestion with the smallest number of additional line elements (Koch et al. 2018).

4 Results

This chapter presents the results of the electricity market modelling. All result parameters are made available as data sets in the data base Zenodo (see Appendix A).

Figure 1 shows the resulting CO_2 emissions (left side) and the variable electricity generation costs (right side) in the German electricity sector for the transformation level A and B for the different configurations of a decentralised market and the reference case, where plants are dispatched on a centralised market.

Figure 1: **CO_2 emissions (left side) and variable electricity generation costs (right side) in the German electricity sector**



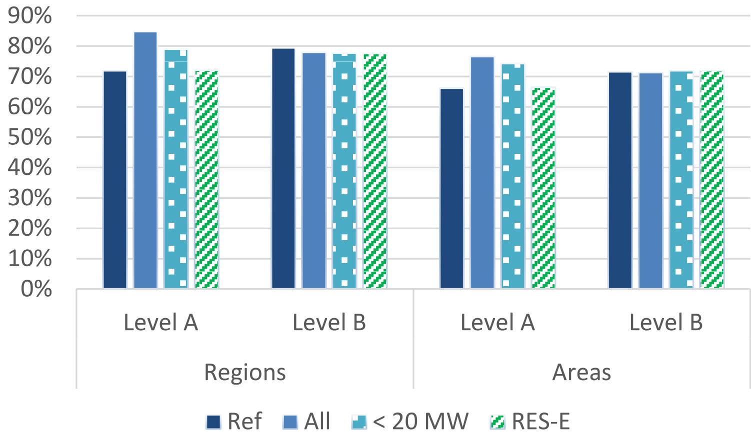
In general, decentralised markets, if designed as priority regional balancing of electricity demand and generation, lead to higher emissions and higher variable electricity generation costs compared to the reference scenario. The extent of this effect depends on the authorised participants and the RES share in the system, and to a lower extent on the size of the decentralised markets. The main effect causing the differences in CO_2 emissions and variable generation costs is that expensive and CO_2-emitting fossil power plants can have higher hours of operation in decentralised markets because they are prioritised over cheaper and less CO_2-intensive generation potential outside the local energy market. The local least cost-based merit order therefore differs from the merit order of the whole electricity system.

For transformation level A, CO_2 emissions increase significantly if all power plants are allowed to participate in regional trading compared to the reference case. This is especially true in the All Reg. case (approx. + 50% of CO_2 emissions). If only small power plants are allowed to participate, the effect is somewhat smaller (approx. + 25%), while emissions are roughly at the level of the reference case if only renewable energy plants are allowed to participate. In Figure 3, it can be seen that for Level A and in all but the RES-E cases, net imports decrease significantly. The additional domestic electricity generation, especially from fossil gas and, in the case of All – Reg, also from hard coal, leads to the increased emissions observed here. As for European-wide emissions, the increase in emissions is mitigated to a certain extent because foreign power plants need to export less to Germany. Therefore, looking at total European CO_2 emissions, additional emissions due to decentralised markets in Germany are between 41 and 56% lower than the ones shown in Figure 1 for the German electricity system. However, it can be assumed that this compensation would not be possible if all European countries implemented similar decentralised markets. In transformation level B, the different variants lead to effects on roughly the same level. This is due to the fact that the adjustment of the dispatch order by a local preference is very low in a market strongly dominated by non-dispatchable RES-E plants.

Looking at the specific variable electricity generation costs (on the right side of Figure 1), i.e. the average costs per MWh of electricity generated, the picture is very similar to the one for CO_2 emissions. The stronger the decentralised merit order of the power plants deviates from the centralised merit order due to regional preferences, the greater the impact on the variable electricity generation costs. Thus, in the case of transformation level A variable electricity generation costs increase by about 50% in the case where all power plants are allowed to participate in the 20 decentralised markets (All – Reg.) and by about 25 % if only small power plants are allowed to participate (<20 MW – Reg. and <20 MW – Area). The costs remain roughly at the reference case level if mainly RES-E plants participate in the decentralised markets, which applies for level A in the RES-E case and for level B in all configurations of the decentralised markets, due to the very high RES-E share.

Figure 2 shows the average local self-supply rates for the different cases examined. The accounting scope to determine local self-supply was chosen according to the size of the decentralised markets, on regional or respectively area level. The parameter ‘local self-supply’ is based on the share of the local load covered by local generation. Its derivation is documented in Appendix B.

Figure 2: **Average local self-supply rates for regional and area level**



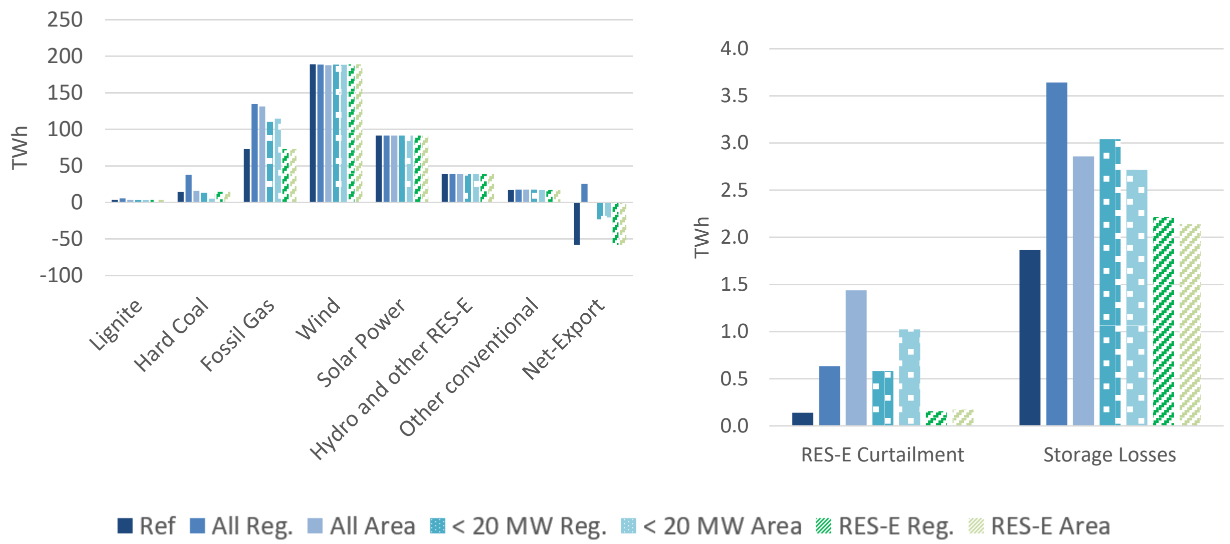
In principle, the level of average local self-supply is lower if decentralised markets are implemented in larger ‘areas’ compared to smaller ‘regions’. However, as can be seen in the reference case, this is only due to the choice of the accounting level. For transformation level A case All, local self-supply can be significantly increased. The average value increases compared to the reference case by 13 percentage points for the regional level and 10 percentage point for the area level. If only small plants below 20 MW are allowed to participate in decentralised markets, a smaller increase occurs (11 percentage points in the regions case and 13 percentage points in the area case). For the case “only RES-E plants” there is no increase in local self-supply, since RES-E generation is at the beginning of the merit order and cannot be optimised compared to the reference case.

In transformation level B, there is a high degree of self-supply of approximately 80% in the regions cases and 72% in the area cases. This is because a broad regional distribution of the mainly renewable generation plants is given in systems with high shares of RES-E plants. Local self-supply cannot be further increased by decentralised markets because, with a share of 87% in electricity generation, wind and solar dominate the electricity system. These non-dispatchable generation technologies can hardly react to local incentives, only for example if flexibility options are used differently. For the case with regional decentralised markets local self-supply decreases slightly by 3 percentage points. This could be due to slightly higher RES-E curtailment and higher storage losses. The reasons for the increase of curtailment and storage losses in decentralised markets are discussed below for the example of transformation level A. In general we can observe that decentralised markets can increase the degree of local self-supply at lower levels of the energy transition, but at higher costs and higher CO_2 emissions. With progressing RES-E expansion, the negative effects of higher costs and CO_2 emissions disappear. Yet the degree of self-supply no longer increases because it is already very high in the reference case without decentralised markets and wind and solar power determine market behaviour. In Appendix C, there is a map showing that the degree of self-supply differs significantly within the regions. Regions with high electricity demand and low RES-E potentials (e.g. large cities or locations with electricity-intensive industry) can only achieve very low degrees of self-supply.

The size of the decentralised markets only has a significant effect on CO_2 emissions and variable electricity generation costs if all power plants, especially the larger fossil power plants, participate in the decentralised markets. Otherwise, the differences between the cases with 20 regions and 457 areas are very small. If all power plants participate in decentralised markets, larger decentralised markets show stronger effects compared to the reference case (higher CO_2 emissions and variable electricity generation costs as well as higher self-supply rates). One reason for this is that in the case of very small-scale markets in many regions, the regional generation capacities are not sufficient for substantial regional load coverage and therefore high shares of the electricity demand must be covered supraregionally.

Since the largest effects occur for transformation level A, a deeper analysis of the modelling results is carried out below. Figure 3 shows electricity generation, market-induced RES-E curtailment and storage losses for the German electricity sector for transformation level A.

Figure 3: Electricity generation (left side), RES-E curtailment and storage losses (right side) in the German electricity sector for Level A



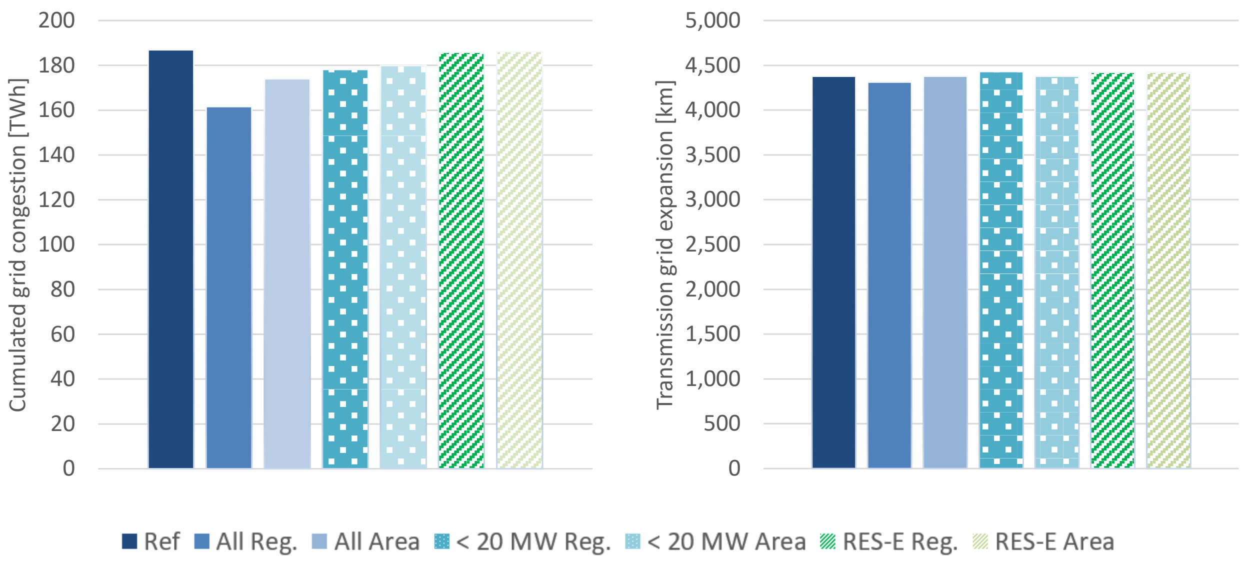
In terms of generation, the greatest differences to the reference case are again seen in the All – Reg variant, where the generation of hard coal and fossil gas power plants increases. This additional electricity generation leads to a significant reduction of imports, compared to the reference case. If the regional markets are designed on a smaller scale or large power plants are excluded from participation, significant changes are only seen in electricity generation from natural gas power plants, including lower electricity imports compared to the reference case. As already observed for the previous indicators, the results for the RES-E cases are almost congruent with the reference case. The increase in hard coal and fossil gas generation observed here cause the increased CO_2 emissions and variable electricity generation costs shown above.

Market-induced RES-E curtailment and storage losses are at a very low level in the scenario studied and tend to be increased by decentralised markets. As regards RES-E curtailment, this is due to the fact that when regional components are considered in the dispatch order, RES-E plants in other regions will only be used later (namely after regional balancing) and can then no longer be used in some hours as they exceed the remaining demand. As a result of incentivising regional balancing of demand and generation, regional storage technologies are increasingly used. This leads to higher storage losses in the overall system. Overall, the effects of RES-E curtailment and storage losses are relatively low and lead to only a marginally lower RES-E share in electricity demand (up to 1 percentage point).

We now turn to effects on the grid. Figure 4 shows the grid congestion of the German transmission grid before its expansion on the left side and the resulting estimated needs for expansion of the transmission grid for Level A on the right. As initial situation for the grid expansion the starting grid of the German transmission grid development plan 2019 (Netzentwicklungsplan - NEP) was used. In addition to existing lines, it considers lines that are at an advanced stage of the permitting process.

For the parameter grid congestion, the number of hours with congestion of the individual line sections are summed up over the year. On the right-hand side of Figure 4 transmission grid expansion needs for the different cases in transformation level A are shown. The grid expansion requirement is determined iteratively by selecting lines from a predefined set[1] until a specified grid overload level can be met[2]. The exact definition and procedure for both grid congestion and grid expansion are described in Appendix B.

Figure 4: Grid congestion before expansion (left side) and transmission grid expansion (right side) for Level A



With regard to effects on the electricity grid, decentralised markets can reduce grid congestion by 14% in the case when all power plants are allowed to participate in the 20 regions' configuration. In the All – Area case, where the size of the decentralised markets is significantly smaller, the alleviation is half of that level only, at 7 %. If only small power plants are permitted (< 20 MW cases), the reduction of grid congestion is approximately at the same level (5% and 4%). In the case with only RES-E plants, grid congestions are roughly at the level of the reference case.

However, the analysis on grid expansion needs shows that for all cases the demand is roughly at the same level (cf. right side of Figure 4). This is due to the fact that optimised local demand coverage may reduce the use of the transmission grid, but typically does not reduce peaks in grid usage significantly. Since the demand for grid expansion is mainly determined by these peaks, the need for grid expansion cannot be noticeably reduced. This correlation is also illustrated in Appendix C with the annual duration curve of the average grid capacity utilisation for the reference case and the All cases, which are the three cases with the strongest difference of grid usage. While in the hours with the strongest grid capacity utilisation all cases are almost on the same level, grid capacity utilisation was reduced in hours with low levels. This results in an overall lower grid usage but not in a reduced need to expand the grid.

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1 Based on the data set of the German transmission grid development plan NEP 2030 first version from 2019.

2 The termination criterion for the iterative process was set to 1 TWh.

5 Discussion and conclusions

The analysis has evidenced a range of power system effects of decentralised markets and how these depend on market design parameters and the overall system status in terms of the share of renewables. The analysis conducted in this paper is based on the German electricity system, i.e. a highly interlinked system with a high grid interconnectivity with neighbouring countries. Therefore, the results and general effects shown cannot directly be transferred to electricity systems which are significantly less interconnected. In addition, the results rely on the definition and the specific modelling of a “decentralised market” as described in the methodology section.

The analysis looks at how these markets affect specific indicators, yet it does not compare these effects to those of other potential instruments. To address specific challenges like reducing the need for electricity grid expansion, more specific instruments like nodal pricing could be introduced. To further evaluate decentralised markets, the corresponding effects of such mechanisms on the same indicators in the same scenarios would be a useful addition. Moreover, decentralised markets can pursue additional objectives that have not been analysed in this study, for example effects on participation and the acceptance of the energy transition, which are large drivers in political discussions about decentralised markets and may in turn lead to additional RES-E or flexibility investment due to increased public involvement.

The analysis shows that decentralised markets – to some extent depending on the transformation level – have either negative side-effects or do not achieve the intended effects on the indicators that have been analysed. CO_2 emissions and variable electricity generation costs tend to increase when decentralised markets are implemented in the German electricity system. To avoid significant additional emissions and rising variable costs of electricity generation, it would be necessary to exclude fossil power plants from decentralised markets. However, it has turned out that if only renewable generators are allowed on the decentralised market, only very small differences occur compared to the reference case with a centralised electricity market. This is due to the assumption that the non-dispatchable RES-E technologies wind and solar will be the dominant RES-E source in the future electricity system. The consideration of local components has only a minor influence on the use of wind and solar power plants, for example through an increased usage of storage technologies and correspondingly higher storage losses. Since in transformation level B the electricity generation from wind and solar, with a share of 87%, is dominant overall, only marginal effects occur in all the configurations of decentralised markets examined.

This shows that the level of the energy transition has a major influence on the effects of decentralised markets. In principle, the higher the share of renewables in the system, the lower the effects of decentralised markets are compared to the reference case. In other words, decentralised markets would lead to higher costs and emissions during the transformation phase, while hardly any effects on the system can be observed once the transformation towards high shares of RES-E has been achieved. This again leads to the conclusion that research has to be done on socio-economic indicators such as acceptance and participation and their possible effect on RES-E deployment. Again, it is important to compare different instruments to achieve higher acceptance for and higher participation in the energy transition. Such an evaluation should also take into account the avoidance of negative effects, such as those observed here for decentralised markets.

The size of the decentralised markets shows a smaller influence on the results. Only in transformation level A, and if all power plants can participate, we can see a significant difference between the cases with 20 regions and 457 areas. In this case larger decentralised markets show stronger effects compared to the reference case (higher CO_2 emissions and variable electricity generation costs as well as higher self-supply rates and lower grid congestion). This is because if electricity markets are too small, regional generation capacities are not sufficient for substantial regional load coverage so that high shares of the electricity demand must be covered supraregionally. We therefore conclude that negative side effects of deploying decentralised markets cannot be managed by only changing the size of the regions. However, the result of the reference case indicates that the larger regions can reduce costs and CO_2 emissions due to a better use of RES-E generation. This conclusion was also drawn for example in Child et al. (2019), Ritter et al. (2019) and Schlachtberger et al. (2017) in the case of greater European market integration.

Although decentralised markets can reduce the load on the grid, no reduction in the need for grid expansion could be observed, as there was no significant reduction in peak loads. One explanation for this is that the decentralised markets operate without taking into account when and where grid constraints occur, so that positive effects on the grid are mere side-effects. This shows that decentralised markets in the form as we have modelled them do not seem to be the most promising instrument to reduce grid congestion and grid expansion. Alternative instruments to address this target are for example nodal pricing (cf. Ashour Novirdoust et al. 2021; Hirth and Glismann 2018) or RES-E localisation that considers electricity demand distribution (cf. Wimmer 2014; Tröndle et al. 2020).

Funding:

This paper is based on research within the project C/sells (grant number 03SIN102), which was funded by the German Federal Ministry for Economic Affairs and Energy (BMWi).

Abbreviations

The following abbreviations are used in this paper.

CHP	combined heat and power plants
CO_2	carbon dioxide
DSM	Demand side management
ENTSO-E	European Network of Transmission System Operators for Electricity
GJ	gigajoule
GW	gigawatt
km	kilometre
Mt	megaton
MW	megawatt
NEP	Netzentwicklungsplan (German network development plan)
NTCs	net transfer capacities
PV	photovoltaic
RES-E	electricity from a renewable energy source
TWh	terawatt hour
TYNDP	Ten-Year Network Development Plan

Appendix A

Data availability

The below described data sets are available under creative commons license on Zenodo: https://zenodo.org/record/4727354

Table 2: Available input and output data

Data	Data type	Geo scope	Transformation level	Unit	Input/Output
Demand	Hourly profiles	Europe	A and B	MWh	Input
Variable RES-E	Hourly profiles	Europe	A and B	MWh	Input
Power plant fleet	Capacities	Europe	A and B	MW	Input
NTCs	Capacities	Europe	A and B	MW	Input
Electricity generation	Annual data	Europe	A and B	TWh	Output
CO_2 emissions	Annual data	Europe	A and B	Mt	Output
Variable costs of electricity generation	Annual data	Germany	A and B	€/MWh	Output
Self-supply rate	Annual data	Germany	A and B	%	Output
RES-E curtailment	Annual data	Germany	A and B	TWh	Output
Storage losses	Annual data	Germany	A and B	TWh	Output
Grid congestion	Annual data	Germany	A	TWh	Output
Grid expansion	Annual data	Germany	A	Km	Output

Input data for Germany

The following table shows the capacities installed for Germany in transformation levels A and B. The data is mainly based on Klimaschutzszenario 95 from Repenning et al. (2015), including an adjustment towards a stronger decentralised generation as described in Kühnbach et al. (2020). While the capacities of wind onshore, wind offshore and photovoltaics roughly double between level A and level B, lignite and hard coal almost completely lose their role in level B. The capacities of gas-fired power plants remain at roughly the same level between the two transformation levels. However, it must be seen that the gas capacities in level B include approx. 25 GW of back-up capacities that only run at a low utilisation rate (approx. 1,000 full load hours).

Table 3: Generation capacities [GW] installed in Germany

	Level A	Level B
Lignite	1.2	0.0
Hard coal	9.3	2.7
Gas	27.9	28.9
Nuclear	0.0	0.0
Other fossil	4.9	4.4
Hydro	5.5	5.8
Wind Onshore	64.6	122.1
Wind Offshore	15.1	37.7
Solar energy	104.7	237.1
Biomass	4.4	0.4
Other RES-E	0.6	1.9

Source: Repenning et al. (2015); Kühnbach et al. (2020)

Table 4 shows the values used for the different flexibility options in Germany for transformation levels A and B. The data for battery storage, pumped hydro storage and demand response is based on Rippel et al. (2019), while the values for electrolysers, electro mobility and power-to-heat are taken from Repenning et al. (2015).

Table 4: Flexibility options in Germany

	Unit	Level A	Level B
Battery storage	GW	6	21
Pumped hydro storage	GW	9	16
Demand response	GW	4	8
Electrolysers	GW	0	42
Flexible el. mobility demand	TWh	11	80
Flexible Power-to-Heat demand	TWh	20	57

Source: Repenning et al. (2015); Rippel et al. (2019)

In Table 5 fuel costs and CO_2 prices for transformation levels A and B are listed. These values are based on Repenning et al. (2015).

Table 5: Fuel costs and CO_2 price

	Unit	Level A	Level B
Crude oil	€/GJ	16.4	25
Fossil gas	€/GJ	9.4	13.9
Hard coal	€/GJ	3.3	4.5
Lignite	€/GJ	1.7	1.7
CO_2	€/t CO_2	87	200

Source: Repenning et al. (2015)

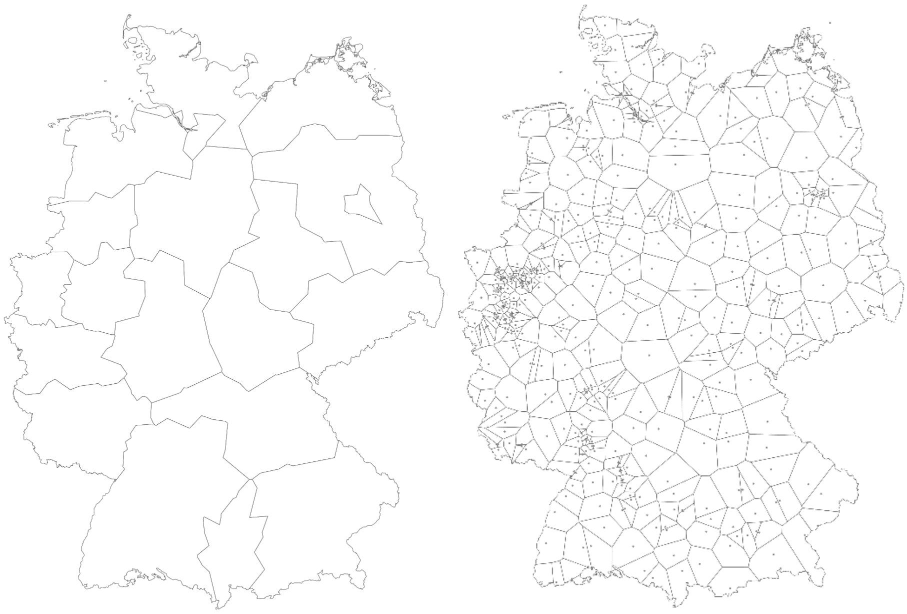
Table 6 shows the keys used for the regionalisation of the input parameters for the German electricity system. Most of the input data used is available on a national level and has to be distributed to the transmission grid nodes by appropriate factors. The procedure for the distribution of RES-E capacities is adapted from the method used in 50 Hertz Transmission et al. (2019a).

Table 6: Regionalisation keys

Input parameter	Regionalisation keys
Wind onshore expansion	Step 1 - Distribution to federal states: Federal state distribution from 50 Hertz Transmission et al. (2019a) Step 2 – Distribution to nodes: ½ Current distribution (repowering) ½ generation potentials
Wind offshore	Distribution from 50 Hertz Transmission et al. (2019a)
PV expansion	Step 1 - Distribution to federal states: Federal state distribution from 50 Hertz Transmission et al. (2019a) Step 2 – Distribution to nodes: Suitable sites for PV installations
Run-of-river	Installed capacity from Bundesnetzagentur (2019)
Power plants	Location if known (Bundesnetzagentur 2019) Additional power plants: Own assumptions
Decentralised power plants (esp. biogas and fossil gas CHPs)	Equal distribution to all nodes
Electricity demand	Industrial load: locations of electricity-intensive industry Remaining load: Population density
Electric vehicles	Population density
PV battery storage	Future distribution of installed capacity from PV plants whose subsidies have ended + installed capacity of PV expansion (cf. Matthes et al. 2018)
DSM	Population density
Electrolysers	Wind onshore electricity generation

Figure 5 shows the structure of the two different configurations for the size of the decentralised markets, with the 'Reg' case on the left side and the 'Area' case on the ride side. Their derivation is described in chapter 3.1.

Figure 5: Structure of the 20 regions (left side) and 457 areas (right side)



Appendix B

Indicator derivation

Self-supply rate:

The capped ratio of local generation to local load if local load exists is derived as follows:

- $g_{r,t}$: generation in region r at time t
- $l_{r,t}$: load in region r at time t
- $s_{r,t}$: $regional$ self-supply ratio $= \begin{cases} 1, & l_{r,t} = 0 \; or \; g_{r,t} > l_{r,t} \\ \frac{g_{r,t}}{l_{r,t}}, & else \end{cases}$

Grid congestion:

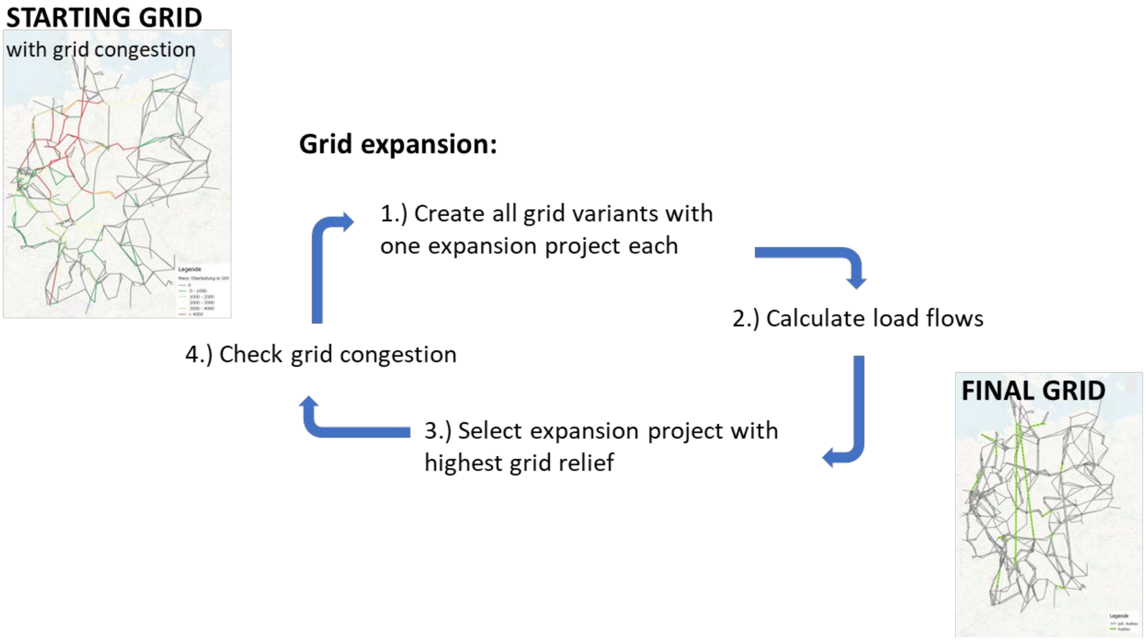
Every hourly line load that would exceed line capacity if no redispatch was applied, is cumulated to yearly values and aggregated to a national value as follows.

- c_l: capacity of line l
- $l_{l,t}$: load on line l at time t
- C: total congestion $= \sum_{l,t} max(l_{l,t} - c_l, \; 0)$

Grid expansion:

Figure 6 shows the scheme of the iterative grid expansion that we used for this analysis.

Figure 6: Scheme of the iterative grid expansion



As shown in Figure 6, the initial point for the iterative grid expansion is a starting grid with its grid congestion. In this case the base grid before expansion is modelled on the starting grid (Startnetz) from the 2019 first draft of the German grid development plan (50 Hertz Transmission et al. 2019b). This grid already incorporates some future power lines where the planning process has reached an advanced stage. The second data set needed is the pool of additional potential lines for the grid expansion algorithm. This data set comes from a model grid provided by the German Federal Network Agency (BNetzA) for the year 2025. Based on the grid congestion of the starting grid the first step of the iterative process is started, where all grid variants that consider one expansion project are created. In the second step the load flows and resulting congestion for all these grid variants are calculated. The expansion projects with the highest grid relief are selected in the third step (we keep more than one configuration for the next step to avoid path dependency in a local minimum). The last step of the grid expansion process comprises checking whether grid congestion for the chosen grid configuration is still above the termination criterion for the iterative process, which was set at 1 TWh of total congestion work. If it is still above, the procedure is continued. If the criterion is met, the last result is used as the final grid.

To quantify the line lengths of the required grid expansion, we us a factor of 2.2 applied to the length of a straight line to estimate actual line length as the real geometry of a future line is not known. This factor was determined from a comparison with the expansion measures in NEP 2019 (50 Hertz Transmission et al. 2019a).

Appendix C

Supplementary illustrations of results

Figure 7 shows for transformation level A the average self-supply rates in the case where all power plants are allowed to participate in the 457 decentralised markets in Germany. The content of the figure is discussed in chapter 4.

Figure 7: Average self-supply rates in the 457 areas for level A in the case All – Area

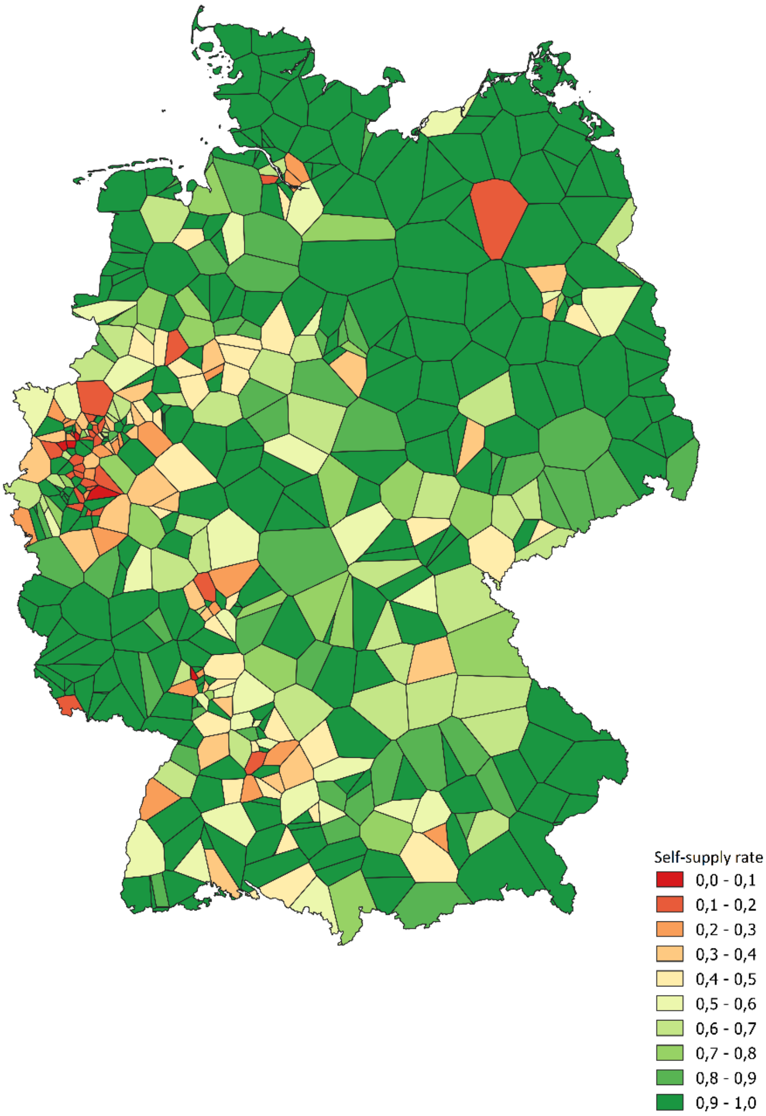
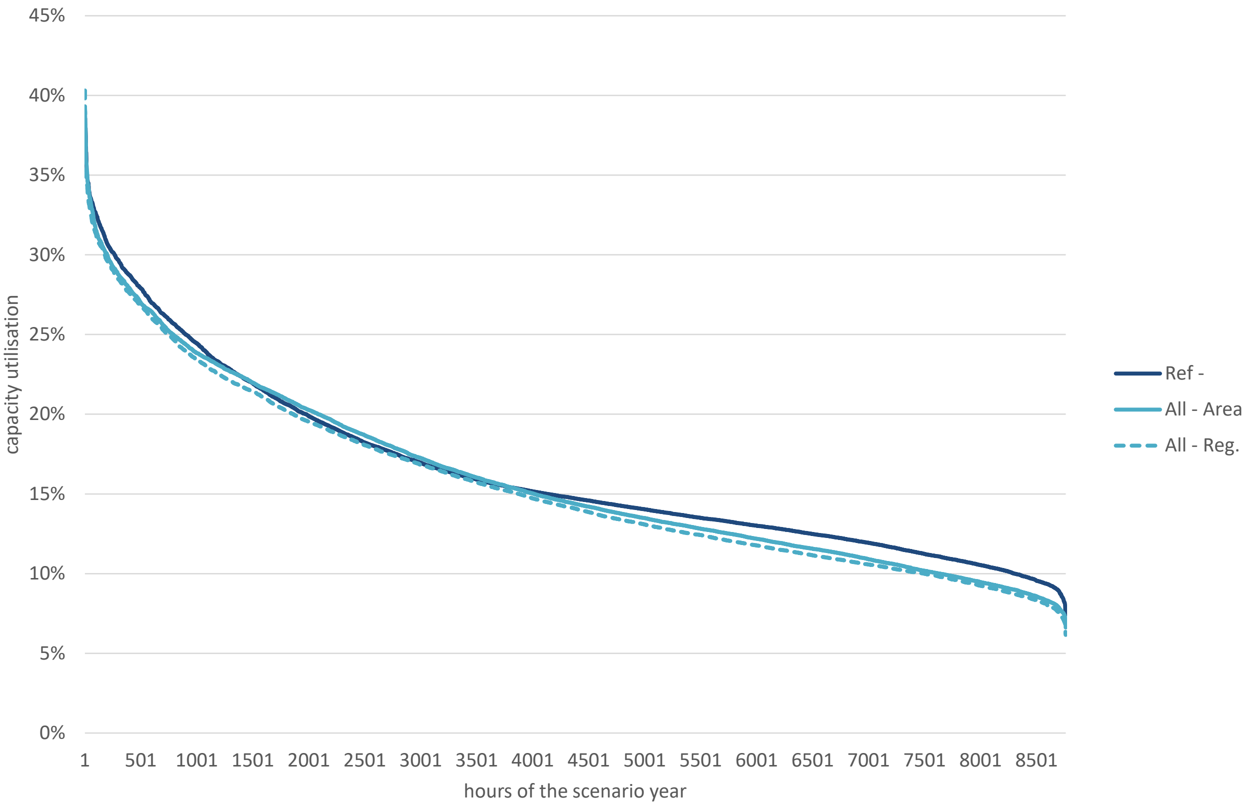


Figure 8 shows the average capacity utilisation of the transmission grid lines for the three cases with the strongest difference of grid usage (Reference, All – Area and All – Reg.). In this illustration, the hours of the year are not arranged chronologically, but according to the size of the parameter value (annual duration curve). The capacity utilisation is estimated after grid expansion and shows the hourly average values of all lines. The content of the figure is discussed in chapter 4.

Figure 8: Average capacity utilisation of the transmission grid lines for level A



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