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Institute for Applied Ecology

Decentralization, regionalization and power lines

Metastudy
about assumptions, insights and narratives

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for the
Renewables Grid Initiative (RGI)

English translation (original study is in German)

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Summary

In the discourse about infrastructure expansion that is robust and for which public acceptance is assured, the relationship between decentralization and the future demands on power grid infrastructures is a critical issue. It includes the whole spectrum of applicable interrelationships, the myriad areas of tension and complexities of centrality, decentralization and so-called “cellular” approaches. The issue of decentralization – which is often handled very vaguely and (too) often features rather crude narratives – requires a nuanced, differentiated analysis.

In a first step the present study reviews and analyzes the different dimensions and aspects of decentralization of electricity generation based on literature reviews. This finds, first of all, that a purely technical approach to the relationship between decentralization and grid expansion (small vs. large installations, connected voltage level) is not a viable approach.

A crucial factor in the context of grid expansion is, firstly, the proximity of power generation plants to electricity customers. If a large share of the power generation is decentralized, the pressures on the electricity grid can naturally be reduced. Secondly, the proximity of the flexibility options (e.g. demand flexibility, storage, back-up capacities) to the electricity customers is of major importance, since such flexibility options will play a fundamental role in an electricity system based on renewables. All kinds of combinations of decentralized and centralized power generation options on the one hand and decentralized and centralized flexibility options on the other hand can arise and are useful with a view to the large range of flexibility profiles. Decentralized power generation options can only result in a lower need for grid expansion if decentralized flexibility options are also available.

The third aspect, however, is ultimately crucial: the control, coordination and market model, which combines consideration of generation and flexibility options and electricity demand. Within the framework of liberalized markets, i.e. with free decisions about production and supplier choice, large-scale (centralized) markets and prices will emerge and determine the use of flexibility options. Beyond optimization of self-consumption it is only possible to avoid or limit this if very extensive isolation of regional markets, e.g. regional monopolies or very restrictive pricing of infrastructure, is possible. As a result, lower power grid needs can only be reliably assumed if self-consumption concepts combine decentralized power generation and flexibility options or if small-scale “cellular” approaches (whereby electricity is produced and directly consumed without being fed into the grid) are used.

Even if the concrete implementation of “cellular” (market) systems or regional markets designed in other ways has not yet been specified in sufficient detail, a number of reliable statements can be made on a qualitative level about the implications of such models. Small-scale control approaches with high shares of decentralized power generation and flexibility options tend to lead to higher costs for power generation and flexibility options in the overall electricity system if the effects of the large-scale interplay of very different electricity demand and generation profiles (portfolio effects) do not arise.

As a consequence, higher power generation (due to energy losses of the flexibility options, curtailments, etc.) would initially be necessary since (for example) overarching

emission reduction targets need to be met. A situation similar to the cost issue also arises with regard to the land requirements for all generation options in the electricity system with the exception of rooftop PV systems.

However, the effort and the implications with regard to the flexibility options would also increase. The additional costs involved could be limited if conventional fossil-fuel technologies (e.g. decentralized gas-fired power plants) are used, which would then lead to higher emission levels in the overall system that should, at the same time, be decarbonized as quickly as possible. If higher emissions are to be avoided, the costs of (decentralized) flexibility options will increase far above the particularly cheap options (which have a limited availability) (if, for instance, not yet matured options like electricity-based fuels would have to be used on a large scale).

From an economic perspective, the costs of the flexibility options should always be compared with the corresponding infrastructure costs. This issue cannot be robustly answered on a purely qualitative level. From an environmental perspective, the significant decrease in power grid capacities does not balance the additional land use and resource consumption described or the higher emission levels that may result.

In addition to the economic and environmental criteria, aspects such as innovation capabilities and acceptance issues are also substantially important. Decentralized technologies and decentralized coordination concepts have indisputable advantages due to their proximity to many relevant actors. However, the question must be raised of whether and to what extent decentralized concepts for power generation and, where applicable, for flexibility options and small-scale control models are needed to a large extent with respect to participation and innovation. Other, selectively designed ways of improving participation and innovation could also be considered.

Lastly, the purely qualitative analysis carried out in the first step also raises the question of whether and when decentralized control models with wide scopes need to be harmonized with the existing regulatory framework for European energy markets.

In a second step, data analyses (with a high spatial resolution) were conducted on the limits of potentials for absolute solar and wind power generation and on the corresponding demand structures (in both cases on a district level). These analyses initially completely exclude the cost or availability issues of flexibility options and contain only quantity balances with a high spatial resolution. They show that, firstly, there is a substantial concentration of demand in the industrial regions in the west and south and in the metropolitan regions of Germany. Secondly, very profitable solar power generation can come about particularly in southern Germany and with the roof potentials in metropolitan regions. Thirdly, very profitable wind power generation is available in north and northeast Germany and offshore. Fourthly and finally, challenges concerning the public acceptance of onshore wind power plants will have a restrictive effect on actionable potentials, especially in regions that are densely populated and have a high electricity demand.

On the level of Federal states (*Länder*) these restrictions decrease but remain clearly evident. Even at the next aggregation level – a total of six regional areas (zones) – the role of electricity imports and exports remains important even if criteria such as costs, land use, emissions, etc., are excluded from the analysis.

Consistently small-scale (“cellular”) concepts were analysed on a district level. These could only be implemented without substantially increasing use of grid infrastructure when flexibility options are applied very widely, which would entail the above-mentioned implications (costs, emissions, etc.). The quantitative analysis also shows that the portfolio effects become stronger, the larger the cells are defined, i.e. larger cells decrease the need for flexibility options and the associated negative effects. It follows that even with cellular approaches applied to larger areas it must be assumed that, regardless of the technological requirements and the costs involved, transregional electricity imports and exports would arise to a significant extent. In any case it should be noted that aside from optimization of self-consumption, no practicable proposals have been made yet for consistently implemented small-scale market concepts.

In a third step, a comparative analysis is conducted for a wide range of models of the German electricity system that have different designs and use very different methodologies. Scenarios that calculate a 20% to 50% lower need for grid expansion have the following characteristics:

- The scenarios assume or determine a strong expansion of onshore wind energy in the “South” zone. The scope of the additional grid expansion resulting for 2030 and 2035 is three to four times, and in extreme cases six times, higher than the values assumed in the network development plans.
- A disproportionate expansion of onshore wind energy in the “West” zone is predominantly assumed or calculated. The additional grid expansion amounts to a factor of 2 to 3, and in two extreme cases to a factor of 7, higher than that assumed in the network development plans.
- Largely, albeit not consistently, a very strong expansion of solar power generation is assumed in the “South” zone. The capacities of PV systems in the “South” zone exceed that of the network development plans for 2030 and 2035 by a factor of 2 to 3.
- For 2030 the relationships between the remaining coal-fired power plant capacities and the necessary grid expansion depend to a great extent on how (additional) renewable power generation is regionalized. For 2035 the amount of coal-fired power generation no longer shapes the dimensions of electricity grid expansion.

The different assumptions of the potentials in the relevant literature were compared, with the result that assumptions for the expansion of onshore wind power generation and partly also for PV power generation for 2030/2035 in the “South” and “West” zones may bring into question the limits of the potentials or that the modelling is conducted using questionable assumptions for the expansion of renewable power generation, at least for the period under discussion.

A review of scenarios with more ambitious expansion paths for power generation based on renewables in Germany shows that the decreased need for grid expansion is temporary and that grid expansion would nevertheless be necessary in the long term.

With a view to the contributions that decentralized control models make to decreases in grid expansion needs, the model simulations show that regional distribution of renewable power generation remains paramount for the differences in grid expansion needs. Regionalization is clearly the most influential parameter, especially with a view to onshore wind power capacities.

With regard to the overall cost effects of different regionalization or control approaches, no reliable quantitative conclusions can be drawn from the available literature since the studies analyzed do not examine these aspects to the extent necessary and do not use comparable approaches. The same applies to environmental factors such as land use or the impact on CO_2 emissions.

Viewing the three steps of the analysis overall, a number of recommendations for action can be derived in addition to the above-mentioned conclusions. Firstly, a structured discourse is needed to clarify whether and in which model or at what times decentralized ("cellular") control approaches – aside from optimization of self-consumption – could be implemented or considered as a variant for grid expansion planning. Secondly, the assumptions for expansion limits of renewable power generation need to be validated. This is the case for onshore and offshore wind power capacities as well as PV power generation in high spatial resolution, at least for the zones and particularly the "South" and "West" zones in Germany. The real land potentiality and acceptance should receive special attention. Thirdly, there is an urgent need to develop a uniform assessment criteria for calculating all the costs and land requirements (for electricity generation plants, flexibility options and infrastructures) in order to enable comparability in future analyses. Fourthly, to improve the comparability of future studies, it would be helpful to develop a pragmatic metric that can be used to compare the grid expansion needs and take into account the different modeling approaches.

The present metastudy is the first comprehensive attempt to analyze the complex fields of tension between decentralization and grid expansion, which have been shaped by different narratives and present many conceptual and data challenges. Further research needs to be conducted on these aspects.

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1. Introduction and background

The energy transition, Germany's most crucial energy and climate policy project, is currently being applied on a broad scale. With renewables accounting for more than one-third of total power generation (and thus mainstream) and expansion targets of up to two-thirds over the next decade, spatial questions pertaining to the conversion of the electricity system into a renewable system have gained increased attention, not to mention considerations concerning centrality and system decentralization. These questions are particularly explosive in view of the planned expansion of transmission grids in Germany.

The debates have even broader implications in which they also directly or indirectly influence public acceptance as well as the cost aspects of different expansion courses and developments for renewable power generation plants, from different flexibility options and coordination systems to market design and issues relating to actors, ownership and distribution.

For transmission grid expansion alone, a large number of issues have become relevant:

- ensuring energy transition-related system and supply security and other current challenges;
- the long-distance transmission of electricity from renewables to centres of consumption, which is more economical in terms of investment and/or production costs and/or is subject to fewer spatial/acceptance limitations and restrictions;
- the phase-out of electricity generation from fossil fuels and its implications for the (transmission) grid;
- the increasing economic appeal of both decentralized (PV and storage) and centralized renewable generation technologies (offshore wind power, in particular);
- the (technical, economical, ecological, regulatory and social) discussion about decentralization or "cellular" approaches;
- the (economic) discussion involving new pricing concepts for infrastructures (price zones, nodal pricing, regional markets);
- the (technical) discussion about "sector integration and coupling";
- the cost implications for the expansion of the transmission grid (e.g. through the transition to wider use of underground cabling).

Unless underlying conditions and driving forces are structured and classified to the extent necessary for the network expansion, an ever more multi-faceted dialogue will result in massive obstacles across the narrative for all processes essential to the discussion, consideration, planning, approval and implementation.

Here, but also in the broader discourse, the question of centrality and decentrality plays a major role, at least on the narrative level (i.e. imagery that creates meaning and orientation). However, in stark contrast to this prominent role, the classifications of centrality and decentralization are unclear and therefore often ambiguous in most of these discourses. For long-term infrastructure projects such as transmission and distribution grids, which may involve considerable lead times, these types of unclear or ambiguous narratives could cause significant problems, especially when these very influential (at least in the German discussion) narratives significantly supersede more comprehensive and above all more transparent evaluation and negotiation processes.

Against this backdrop, the metastudy presented here and compiled by the *Renewables Grid Initiative* (RGI) pursues two central objectives:

- a compact qualitative review of the previous analyses of very multi-faceted centrality, decentralization and cellular concepts (very diverse in terms of differentiation and evaluation criteria and often highly abstract), with the aim of identifying reliable findings, questions of consideration and their dimensions;
- a quantitative comparative analysis of the present modelling work, in which the areas of tension between centrality, decentralization, cellular concepts and network expansion have been analysed in broad terms.

The discussion about the narratives of centrality, decentralization, and cellular concepts is often relatively abstract and in some cases very selective. The overlapping with actual questions that need to be answered when power grids are build or upgraded is unclear. These questions are generally numeric and geographically specific.

The aim of the metastudy presented here can only attempt to examine, structure and, where possible, compare material currently available at this stage. Greater attention should be paid to improving transparency, not on creating additional original modelling work or analyses.

The analyses are divided into four parts. Chapter 3 attempts to systematize and specify the concepts of centrality, decentralization and cellular concepts and their dimensions and evaluation criteria in literature. Implications determined by relatively reliable trend indicators strictly based on qualitative research were used. Limited potential plays an important role for many of the actual issues; Chapter 3 subjects them to a more detailed and quantitatively sound spatial analysis. Chapter 4 describes the quantitative studies on spatial aspects; the underlying assumptions and methods are described in brief and subjected to a comparative analysis. Chapter 5 closes by summarizing the results of the various analyses, drawing conclusions, and identifying research needs.

2. Specification and conceptual classification of centrality, decentralization and cellular approaches

The discourse on centrality, decentralization or the cellular approach (hereinafter summarized as decentrality) is diverse and multi-faceted, sometimes unclear, often very abstract and conducted from very selective points of view.
To be able to process the very broadly diversified concepts of decentrality systematically, even if only to have a general idea, a workable specification of the unclear concepts of decentrality is required firstly and secondly a differentiated view from several perspectives. The current analyses (Agora Energiewende 2017, Bauknecht et al. 2015, Bauknecht et al. 2017; Schill et al. 2016, Canzler et al. 2016, VDE/ETG 2015) differ in this respect considerably.

On the discussion of decentrality concepts, Agora Energiewende (2017) differentiates between

- six different decentrality aspects: the role of self-generation; the regional distribution of generation and consumption; the regional marketing of green electricity; regional smart grids and/or smart markets; the role of small players (citizen energy); and the role of municipal businesses,
- and four different decentrality dimensions: grid topology; economic; social and political dimensions.

Bauknecht et al. (2015) makes a distinction between different characteristics and evaluates them using the following criteria:

- the energy supply systems are characterized based on generation connections; spatial distribution; the level of integration for flexibility options and overall system control strategies,
- criteria involved for the evaluation are: economic impacts; supply security and system complexity; ecological implications and energy efficiency and governance aspects; the democratic nature of the energy supply and the distribution of ownership of the electricity supply infrastructure.

In the Bauknecht et al. (2017) overview of different system control concepts, the following classifications are made:

- the need for flexibility and the use of flexibility
- electrical grid operation, losses and expansion requirements
- system complexity
- energy consumption, resources and emissions, and
- ownership distribution, actor diversity and participation

A review of the debates on (de)centralized energy systems by Canzler et al. (2016) differentiates between the following viewpoints:

- the technical/natural science perspective on different characteristics
- the economic perspective on cost efficiency, as well as consumer preferences and local cost and beneficial effects
- the spatial sciences perspective with a focus on area requirements, and
- the social sciences perspective, in which public acceptance, opportunities for participation, and fairness with the distribution of benefits and burdens in the forefront.

Network-based regionalization of electricity markets is another hot topic. Some of the concepts discussed here are highly specific and tested in practice but otherwise still extremely vague in terms of economic impacts and preconditions, adaptability to the current regulatory system, political implications, and feasibility (Rave 2016, Agora Energiewende 2017):

- An initial radical approach is the introduction of a nodal pricing system that fully (and centrally) coordinates the wholesale market and the electricity grid, as is the case in some parts of North America;
- the prevailing practice in Europe involves electricity pricing zones through a large-scale coordination of "re-dispatch" measures, feed-in management and grid expansion/reinforcement;
- a radical approach of a completely different kind forms the basis of broad-based (i.e. beyond niche or special segments), regional green electricity market models with decentralized trading centres and zones whose prerequisites, design, implications and practical feasibility have so far consistently remained very vague;
- there are various hybrid approaches under discussion among these basic models, in which regionalization incentives are pursued not only through network pricing or the reliance on stable consumer preferences, but possibly through other approaches (regional components in financing mechanisms, sharing network costs, etc.).

Decentralization is lastly discussed from the rather highly aggregated perspective of fiscal federalism regarding decision-making powers (Gawel & Strunz 2016):

- Centralization of political decision-making powers is discussed primarily focussing on scale-based effects, economies of scope and spill-over effects;
- decentralized decision-making powers are discussed with regard to the innovation effects of competing decentralized systems, the adaptability to regional preferences and the accountability of political decisions.

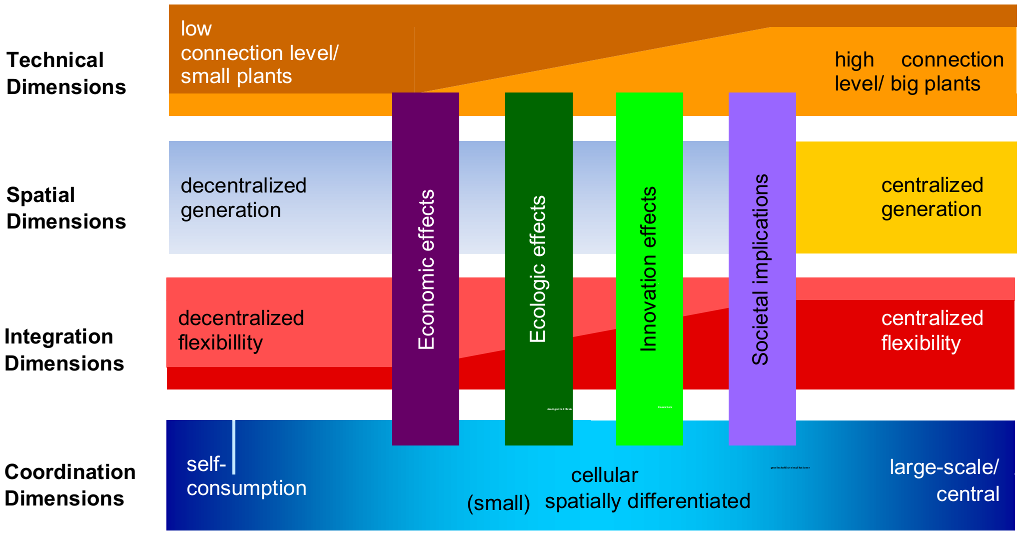
Despite the differences in all these analyses, all have these three key findings in common:

- the coming electricity system will have to contain and connect both centralized and decentralized elements;
- technical feasibility, economic viability, the achievement of ecological goals and compatibility with the existing regulatory framework (e.g. liberalized EU energy markets) as well as public acceptance are necessary prerequisites for the energy system conversion;
- in essence, these and other aspects must be weighed and decided upon within transparent and fair political processes.

A central problem is that the different facets and dimensions of consideration processes are not subject to a uniform evaluation metric. They depend to a large extent strongly on basic economic and socio-political convictions, but also on preferences (or presumptions of preferences) with regard to consumers and political decision-makers, which often have a strong situational component.

Against this backdrop, in addition to the quantitative studies in Chapters 3 and 4, an attempt will be made to subject the facets of decentrality outlined in the above analyses to an orienting classification.

Figure 2-1: Decentralized, central, cellular: The different dimensions and evaluation aspects



Source: Öko-Institut

Ultimately, almost all the technical, spatial and coordination aspects discussed in the above analyses can be classified in the model shown in Figure 2-1.

Only in the synopsis can strong conclusions be drawn for the economic, ecological, innovation and social classification of decentrality, regardless of whether such classifications are possible on a purely qualitative level or whether a detailed quantitative evaluation of the specific present situation or characteristic is required.

The overview makes it clear in the first place that the spatial classification (i.e. centralized or decentralized) should be separated from the technical parameter of installation size. Even if small power generation plants (with connection to low voltage levels) are often built close to consumption, this by no means applies in reverse. Even large installations can be centrally located (housing estates, industrial parks, etc.). From a spatial and technical perspective, proximity to consumption is therefore a much more significant descriptive dimension for the characteristics of an energy system than the purely technical characterization of small or large or the type of grid connection. The degree of proximity to electricity customers that can be achieved in a system is initially dependent on the limits of potential and the economic efficiency of the individual production variants, but also on ecological factors such as land use or the limited acceptance of centralized power generation plants, especially when these are not small installations. From a perspective limited to the proximity of generation plants to consumption, a larger scale centralized power generation with greater diversity would generally lead to fewer grid expansion requirements.

An abstract assumption can be made with regard to the evaluations of different regenerative generation options for very centralized (PV) small-scale systems. They may show public acceptance and land use advantages but are more likely to be more costly. Under the conditions prevailing in Germany, lower-yield wind turbines built near larger centres of consumption would likely use more space for the same amount of renewable electricity (with the same amount of greenhouse gas emissions), resulting in lower public acceptance than for more decentralized installations. For all other system constellations and for all other evaluation aspects, reliable qualitative classifications are hardly possible. Cost aspects depend to a large extent on the cost differences between more or less profitable locations and the actual costs of transmission and distribution grid expansion (e.g. extensive underground cabling).

In addition to the spatial arrangement of generation plants, flexibility options (e.g. demand flexibility, backup power plants, storage facilities) relevant for centralization and decentralization classification, especially in a system with a very high proportion of variable regenerative electricity generation. These options can be installed centralized or even decentralized, whereby centralized generation units do not necessarily have to be associated with centralized flexibility options (as is the case of flexibility options associated with hydropower resources in Scandinavia or the Alpine region – see SRU 2011). At the same time, a decentralized power generation system does not automatically have to lead to decentralized flexibility options. Here, too, limits of potential as well as economic, acceptance and, where applicable, ecological questions form decisive evaluation criteria and framework conditions. In view of grid expansion requirements, the only way to make a sound assessment is to have an overall view of the power plant fleet and the flexibility options. Especially when more complex flexibility options such as Power to X (PtX) technologies are to be envisioned, the spatial distribution models connecting generation and flexibility options will often differ from one another, resulting in consequences for economic efficiency, ecological effects and acceptance (considering grid expansion in each case respectively).

Here too, on a purely abstract level, reliable evaluations can only be made in some areas. Centralized small system combinations with centralized and few flexibility options offer public acceptance advantages. However, it is more likely to be associated with disadvantages in view of overall economic efficiency (primarily because of the high cost of many flexibility options). For all other system constellations and evaluation aspects, no reliable classifications can be made at the qualitative level.

Ultimately, however, the control dimension of the overall system is decisive in many respects. At one end of the spectrum is the case of self-consumption, in which generation and, if necessary, flexibility options (above all storage) is/are strictly aligned with the location and self-consumption configuration. In contrast is central control, e.g. based on a system-wide price indicator. Other variants of such extreme models (cellular concepts, regional markets, etc.) can only be developed if grid connections to the surrounding system do not exist (any more), are significantly and above all heavily priced or the corresponding sub-markets are restricted by regulation (e.g. by area monopolies). Cellular concepts or regional markets, which focus solely and to a considerable extent on stable consumer preferences, tend to appear less sound in terms of scalability.

A series of relatively secure classifications can be made from the control perspective:

- Owners and operators with corresponding preferences show a strong acceptance of self-consumption models. Whether and to what extent widespread acceptance can be maintained in the broader social realm depends on whether regressive distribution effects can be mitigated or avoided by changes in the regulatory framework.

- Centralized control models are highly likely to offer ecological benefits, such as reduced land use or fewer harmful emissions, lower resource consumption and lower energy losses (due to a reduction in the use of flexibility options) because of the full portfolio effects in generation and flexibility options and the resulting reduced need for capacity expansion.
- The classification of cellular concepts depends to a large extent on the layout of the cells. If appropriately designed, they will regularly show higher detection rates for flexibility options and higher innovation rates. Other than self-consumption models, their applicability is for the most part questionable, especially their compatibility of smaller cells with the greater regulatory concept and public acceptance.

Concerning all other evaluation dimensions, no reliable evaluations can be made at a purely qualitative level.

On a societal participation level, connections to technical, spatial and coordination dimensions are not necessarily close as very different questions emerge:

- Who are the participants, or rather, who can participate in
  - power generation?
  - flexibility options?
- Who can take part
  - with regard to (different) decisions?
  - in terms of economic benefit (and risk)?
  - also: technical?
- Who will be faced with encroachments on vested rights?
- Which profiles and/or conflicts arise in terms of participation, risk bearing and vested rights?

Risk bearing and ownership interventions are not exclusively, but largely geographically confined or can be specifically allocated, so material or non-material gains from spatially allocable technologies can at least in principle provide the advantage of acceptability – but only if everyone benefits from participation, not only those subjected to risks and infringements on property rights. With flexibility options that are gaining in importance beyond the first renewable energy phase and established to some degree in other spatial contexts, along with the more complex and often supra-regional coordination mechanisms, this situation, however, can never be taken for granted.

The wide range of different dimensions and the very different evaluation criteria call for specific considerations and classifications. However, based on total system analyses which in turn are indispensable for the expansion of transmission grid systems, and on the (quantitative) analyses available to date, these are feasible only to some extent. The following data and study comparisons must therefore be based on these assumptions and simplifications:

- An essential determining factor for different models of power system development towards renewables, which is expanding with great momentum, lies in the geographically diverse limits of potential for renewables, but also in the spatial structure of consumption. This is not only about technical or economic potentials, but also about acceptance-related (area) barriers.
- The present study situation does not yet allow systematic cost-benefit comparisons across studies involving different assumptions regarding individual cost items, but also the diverse interpretations of non-economic restrictions. In view of the recent and upcoming cost degression and the complementarity of transmission and distribution grid expansion costs, the cost of generation options and grids are surely a differentiation criterion of diminishing importance. Beyond very low-cost options, the most essential cost differences probably occur in the flexibility options, which can become significant if consistently centralized and controlled.
- The adaptability of the different development variants of the electricity and energy system and their implications for grid expansion for the current Regulatory Framework for Energy Systems in Germany and Europe are largely excluded in the following quantitative analyses. For control systems with a strong regional steering effect, both centrally oriented and currently well specifiable systems such as nodal pricing and strictly local or regionally oriented market models (which remain extremely vague) will need to extensively modify the market and regulation model prevailing in the EU. This can hardly be assumed, at least not in the coming decade.

The quantitative subsequent analyses will therefore have to concentrate primarily on regionalization models and their interactions with grid expansion requirements. On the basis of such models, however, orientational conclusions can also be drawn for land consumption and acceptance. After all, the data is used to evaluate aspects such as system costs and other relevant parameters, insofar as they have been determined and documented.

3. Limits of potential

3.1. Preliminary remarks

The increase of regional renewable electricity generation plants plays an important role in grid expansion scenarios. For wind-onshore power plants in particular – regardless of the issue of public acceptance – the question arises as to the absolute generation potential of state-of-the-art technology, i.e. the limitations of current technology.

Therefore, the modelling study comparison is preceded by some potential estimation analyses. This limit of potential is then included in the study comparison in order to be able to assess the quantitative characteristics of potential exploitation scenarios.

3.2. Basis for comparison

The studies in this metastudy differ in terms of their regional analysis. Regional distribution of energy generating installations plays a key role in those studies focussing on decentralization. In order to be able to compare the regional distribution between the individual scenarios, the lowest common aggregation level was selected as the basis for comparison. The potentials analysis is also based on this level of aggregation.

Table 3-1: Zone aggregation for the qualitative comparison of the individual studies

Zone	Name	Federal States
1	North-West	Schleswig-Holstein, Bremen, Hamburg, Lower Saxony,
2	North-East	Mecklenburg-Western Pomerania, Brandenburg, Saxony-Anhalt, Berlin
3	West	North Rhine-Westphalia
4	Middle	Hessen
5	South-East	Saxony, Thuringia,
6	South	Rhineland-Palatinate, Saarland, Baden-Wuerttemberg, Bavaria

Source: Öko-Institut

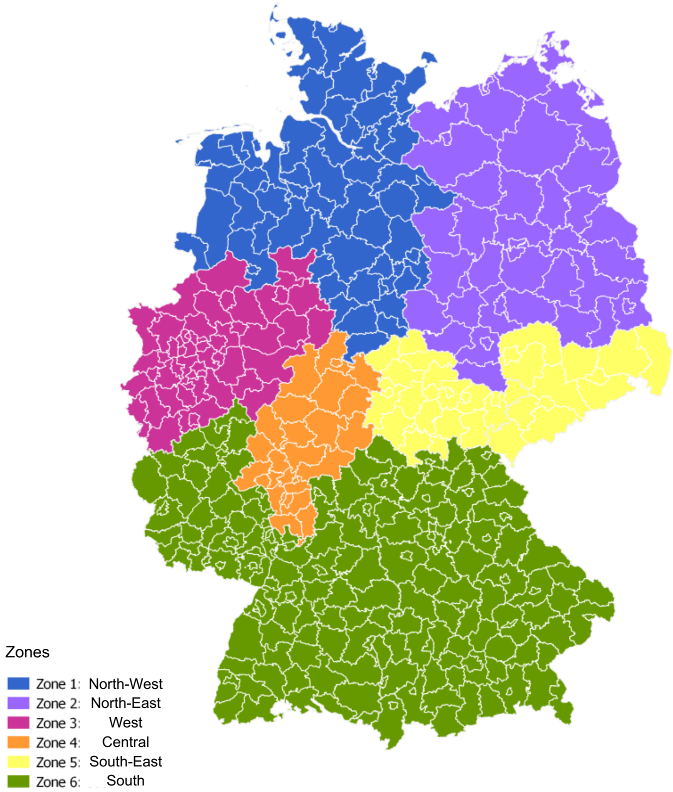
The 402 districts are selected as a starting point for statistical comparisons and for the evaluation of potentials. At this level, a complete and verified data set is established for both regenerative generation potential and demand.

The first relevant level of aggregation is the federal states (*Bundesländer*). At this level, many study authors can summarize and provide their findings.

In order to integrate the results of the BMWi long-term scenarios into the comparison, the last regionally resolved basis for comparison is a "zone" level consisting of six regions (see Table 3-1 and Figure 3-1). This is roughly the equivalent of the aggregation form selected for the long-term scenarios.[1]

[1] The boundaries of the zones do not run along federal state borders in the BMWi long-term scenarios. However, since the data of the other scenarios are available at federal state level, the zone boundaries must be delimited along the federal states. For this reason, these inaccuracies with regard to zone allocation must always be taken into account when evaluating the BMWi long-term scenarios.

Figure 3-1: Aggregation level of the quantitative comparison of the individual studies



Source: Öko-Institut

3.3. Limits of cellular potential

The aim of the following analyses is to gain insights into the regional demand structure and regenerative generation potential. Thus, the question can be narrowed down as to which theoretical possibilities arise within the individual cells to cover requirements.

To achieve this, annual electricity demand and renewable power generation potential at the district level was compiled and the two data sets were combined in such a way as to be able to assess the theoretically maximum possible annual demand coverage from renewables in these units.

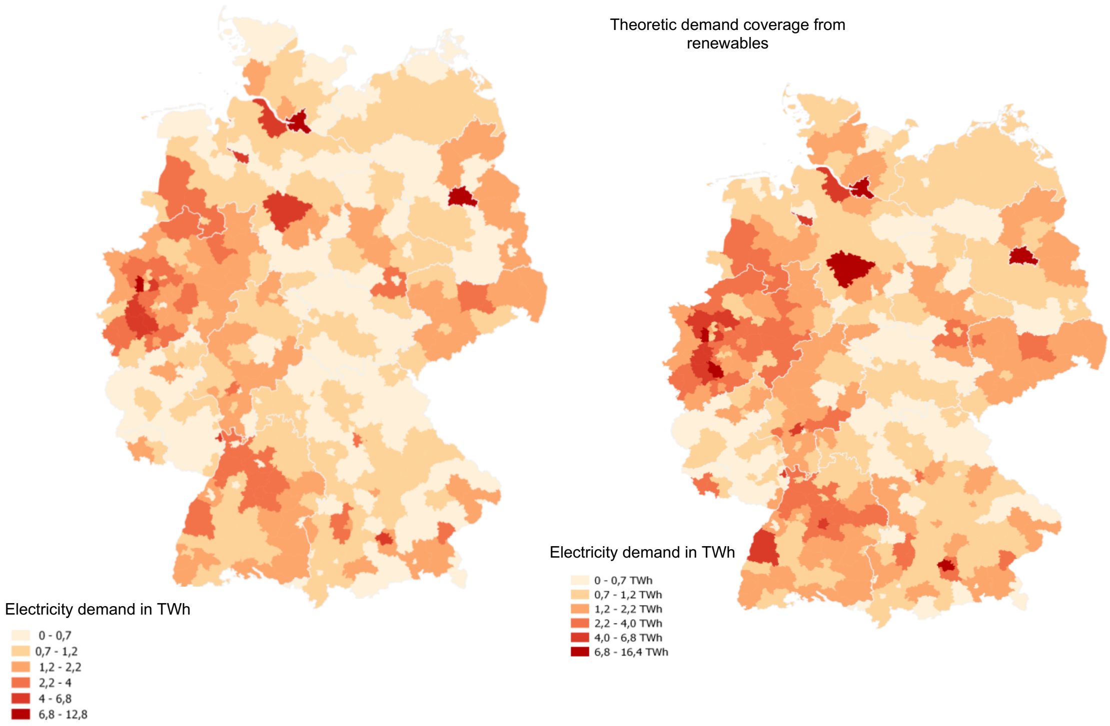
The estimation is based on the assumption that any quantity of generated power can be stored between cells for as long as desired, i.e. that a cell's storage capacities are available for an unlimited period. Costs arising from demand coverage are not considered as the perspective here initially focuses only on the technical or acceptance-side limits of potential.

The analysis is based to a large extent on the data used in the study titled *Stromsystem 2035+* (Electricity System 2035+) conducted by Prognos and Öko-Institut at district level.[2] In these analyses, land potential (taking into account land use and nature

[2] The results of these model analyses have not yet been published.

conservation restrictions), and empirical values on the relationship between land available in principle and land use eligible for approval serve as the basis.

Figure 3-2: Annual electricity demand by district for the scenario year 2030 (left) and 2050 (right)



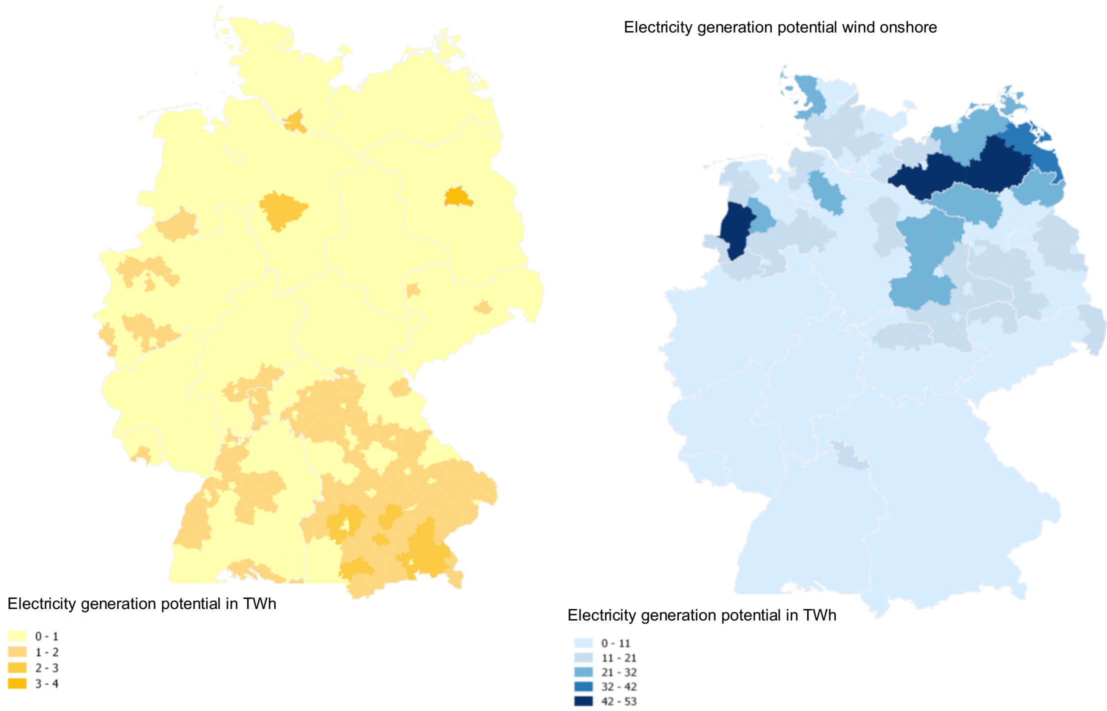
Source: Öko-Institut

The annual electricity demand at district level determined by Prognos was used as a basis for the 2030 scenario year (see Figure 3-2 (left)). The annual demand for electricity in this scenario is 481 TWh. The district with the highest demand is Hamburg at 13 TWh. The regional annual demand in the scenario year 2050, in which the annual demand for electricity rose to 585 TWh due to increasing sector integration, was also presented for comparison (see Figure 3-2 (right)). These consumption levels are well below those of scenarios suggesting a more intense electric power energy system. However, in the sense of a moderate overall classification and taking into account the whole range of uncertainties (emission reduction targets, role of imported CO_2-neutral fuels, etc.); this exemplary approach makes sense in view of the research pursued here.

The renewables considered are hydropower, photovoltaics, wind onshore, wind offshore and biomass. Hydropower and biomass is assumed for power generation of the above project for the scenario year 2050. Annual electricity generation from hydropower is 22 TWh and 11 TWh from biomass. While a rational exploitation of potential can be assumed for hydropower, for biomass it is excluded due to conflict of use reasons.

Electricity generation from wind turbines was also taken over unmodified from the WWF project for the scenario year 2050. No estimation of the maximum possible potential was made here. This is also not necessary for a regionalized analysis of the relationship between generation and demand, since all districts to which offshore wind power generation is already allocated have a (significant) generation surplus. Annual electricity generation from offshore wind farms is 216 TWh.

Figure 3-3: Annual electricity generation PV (left) and wind onshore (right) as maximum potential at district level



Source: Öko-Institut

In the "WWF Electricity System 2035+" project, in the "Focus Solar" scenario set, PV electricity generation was advanced as much as possible by 2050, whereby a maximum development of rooftop systems (roughly two thirds of the total potential) and a significant proportion of additional ground-mounted systems (approx. one third of the total potential) take effect. These considerations do not take into account the maximum available area as a central restriction but consider to what extent photovoltaic systems with a high proportion of own consumption storage can contribute to meeting demand without creating additional storage requirements. The district data for this scenario for the scenario year 2050 is used in this analysis to estimate maximum potential. Annual power generation from PV systems, and thus the maximum potential assumed here, amounts to 292 TWh. The district with the highest annual electricity generation from PV systems is Berlin (4 TWh).

The available potential areas for wind energy expansion form the basis for estimating the maximum power generation potential from wind onshore plants. Data compiled by Christ et al. (2017) and made publicly available are applied here. When determining potential, various relevant data sets are combined in order to maintain distances to settlement areas, flora and fauna habitat (FFH) areas, and bird and landscape conservation areas. The procedure for determining potential is documented (Söthe 2015) The potential area in assessment is 27,244 km^2, which corresponds to about 7.6% of Germany.[3]

Further data and assumptions are required in order to be able to draw conclusions on potential power generation. Power generation results from the output and full-load hours of a plant. The expected full load hours depend on the turbine type, the wind category of the site and the surface roughness of the terrain. Wind category information for Germany is taken from the weather data of the German Weather Service.[4] Surface roughness information was determined using Corine Land Cover data.[5] The reference was an Enercon E 70 (2 MW) plant.[6] Depending on the wind category, values of 1,800 h/a (wind category 5) to 2,400 h/a (wind category 1) were assumed as full load hours.

All existing plants are excluded and substituted by new plants with higher area-specific power generation as this potential is to be fully exploited. The referenced new plant occupies an area of 0.031 km2/MW.

Based on the above assumptions, roughly 1,857 TWh of electricity could be generated in Germany (see Figure 3-3 (right)), when the entire area for wind onshore turbines is claimed. The northeast has the greatest potential for wind-based power generation. The district with the highest generation potential is the Mecklenburg Lake District at 53 TWh.

Table 3-2 shows federal state-specific power generation potentials from wind-onshore plants (theoretical and realistic). These potential limits are summarized under the heading "theoretical"; further restrictions on acceptance and nature conservation are accounted for under the heading "realistic".

3 The Renewable Energy Agency has also carried out an estimation of potential, but limited the potential area to a maximum use of 2% of Germany (cf. (AEE 2015)).

4 WebWerdis (Web-based Weather Request and Distribution System)

5 See Keil et al. (2011) and http://www.renewable-energy-concepts.com/wind-energy/wind-basics/roughness-length.html

6 According to the current state of the art, the selected reference system shows comparatively low performance. A larger wind-onshore system has a need for space that increases linearly with increasing output. Consequently, assessment parameters are only slightly influenced by this reference system.

Table 3-2: Electricity generation potential from wind energy (onshore) - per federal state

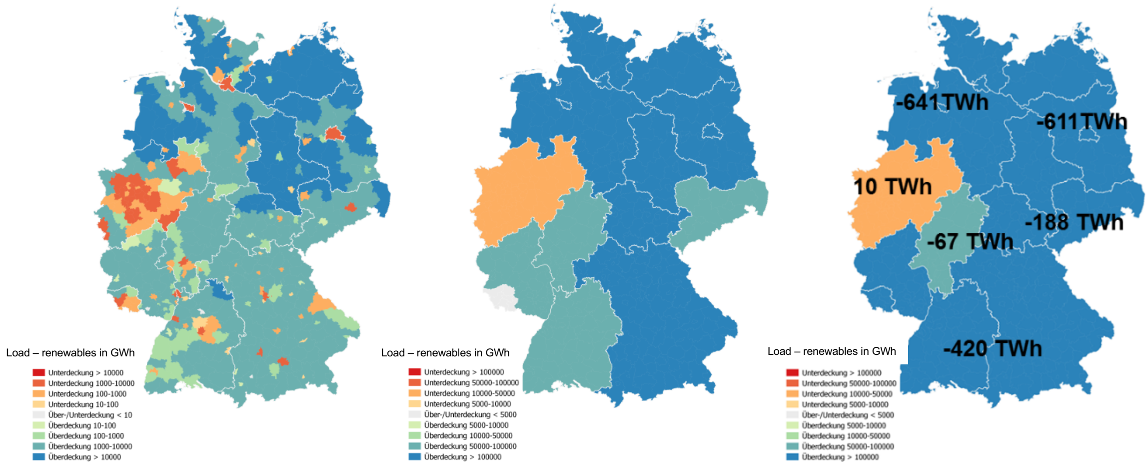
Federal State	Generation potential theoretical	Generation potential realistic
	TWh	TWh
Schleswig-Holstein and Hamburg	112	35
Lower Saxony and Bremen	383	54
Subtotal North-West	*495*	*89*
Brandenburg and Berlin	190	36
Mecklenburg-Western Pomerania	198	18
Saxony-Anhalt	220	25
Subtotal North-East	*608*	*79*
North Rhine-Westphalia	63	24
Subtotal West	*63*	*24*
Hesse	81	9
Subtotal Central	*81*	*9*
Saxony	68	8
Thuringia	134	7
Subtotal South-East	*202*	*15*
Rhineland-Palatinate	76	17
Baden-Wuerttemberg	108	8
Bavaria	221	10
Saarland	3	2
Subtotal South	*408*	*37*
Total Germany	1,857	253

Source: Öko-Institut

If the regenerative generation potential is deducted from the demand, the result is the residual annual demand for the individual districts (see Figure 3-4 (left)). Red districts show a supply deficit; green to blue district supply is more than sufficient. These thus have the theoretical possibility of meeting their demand "independently" when regenerative generation potential is fully exploited with the support of storage, whereas a red district is not able to do so even under "ideal conditions". Large-scale cities generally are districts with a higher demand than supply.

A regional concentration of districts in North Rhine-Westphalia with insufficient supply is evident. If the data are aggregated at territorial federal state level and then at zone level, a demand shortfall of 10 TWh will continue to exist in North Rhine-Westphalia (see Figure 3-4 (middle and right)).

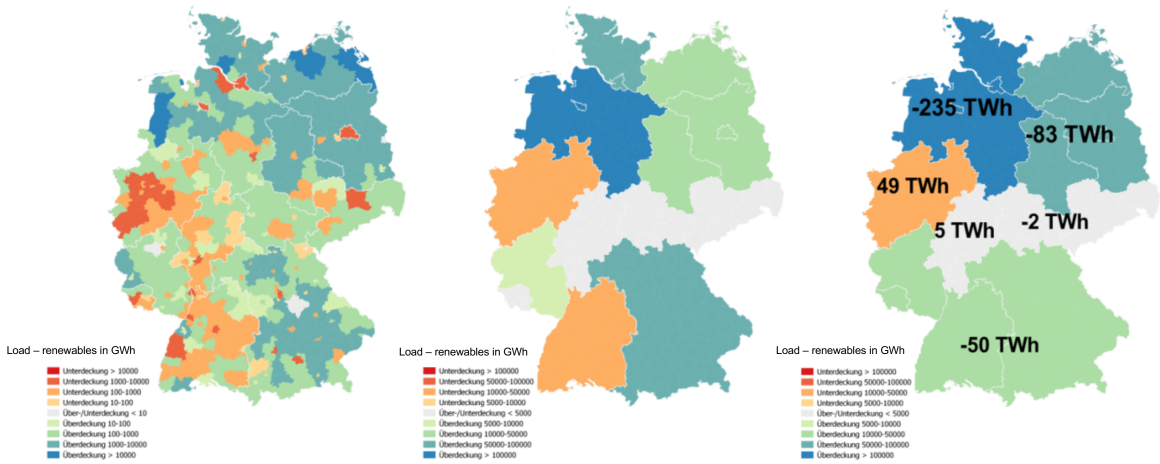
Figure 3-4: Theoretical supply of electricity from renewables at district (left) and territorial federate state (centre) and zone levels (right), 2030



"Unterdeckung" = shortfall

Source: Öko-Institut

Figure 3-5: "Realistic" supply of electricity from renewables at district (left) and territorial federate state (centre) and zone levels (right), 2030



"Unterdeckung" = shortfall

Source: Öko-Institut

The number of districts with insufficient supply is more likely to increase if potential analyses do not focus exclusively on the available areas, but also if further low acceptance or environmental protection constraints enter into effect (see Figure 3-5).

Stored wind-onshore energy in the "realistic" variant corresponds to that of the "Focus Solar" scenario of the "Future Electricity System 2035+" project and amounts to approximately 253 TWh in the scenario year 2050.[7] In addition to North Rhine-Westphalia, the number of districts located in Hesse and Baden-Württemberg with insufficient supply increase taking these restrictions into account. Deficits will then continue to remain at the federal state level: North Rhine-Westphalia, Baden-Württemberg, Hesse, Saxony and the Saarland can not independently meet their demand even with infinitely large amounts of storage, whereas in Lower Saxony there is a generation surplus of 167 TWh. Even when aggregated to the zone level, the "realistic" generation potential is not sufficient in North Rhine-Westphalia and Hesse and in very short supply in Saxony/Thuringia.

And even if it is taken into account that the "realistic" potential variant was determined on the basis of very restrictive framework conditions in order to specify a robust lower potential limit, it becomes clear that limits of potential derived from holistic considerations will play an important role in onshore wind power.

3.4. Outlook: Inclusion of acceptance considerations in onshore wind expansion planning

Within the framework of the VerNetzen project,"[8] social-ecological criteria regarding the expansion of wind energy and the transmission grid were developed, with the help of which soft criteria such as acceptance could be taken into account in electricity market modelling. Building on this, the BuergEN project[9] explored the possibility of including some of these criteria in a scenario.

The "load degree" was proposed as a criterion for assessing the regional contribution to the energy transition in relation to wind onshore turbines. The load degree is an indicator of the impact of wind turbines on the population and is collected at district level. It is calculated as a product of the proportion of the area used for wind energy in relation to district area and population density:

$$B = \frac{A_{wind,LK}}{A_{LK}} \times \frac{pop_{LK}}{A_{LK}}$$

The higher the load degree, the greater the impact on the population (Degel et al. 2016). A high population density tends to have a higher degree of load, especially if the district

7 For comparison: In addition to available space potential, the Renewable Energy Agency has established the rule that a maximum of 2% of the area may be used for wind onshore systems. In the long term, with this additional restriction a potential electricity generation from wind energy of up to 390 TWh could be exploited (AEE 2015).

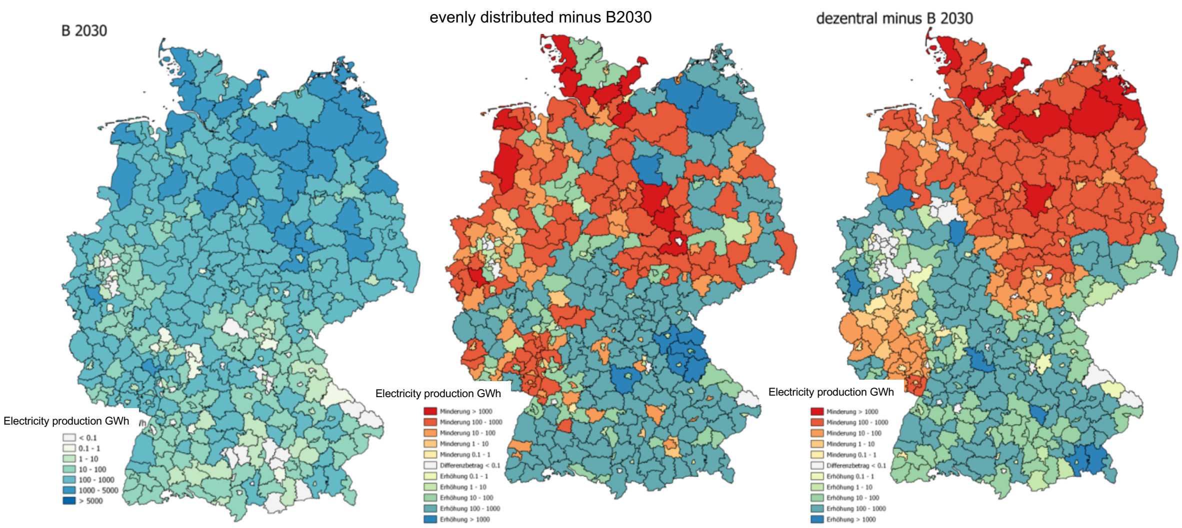
8 VerNetzen. VerNetzen. Socio-ecological and technical-economic modelling of development paths of the energy transition (see http://www.transformation-des-energiesystems.de/sites/default/files/VerNetzen-Kurzbeschreibung.pdf).

9 BuergEN. Perspectives of citizen participation in the energy transition, taking distribution issues into account (see http://www.uni-flensburg.de/fileadmin/content/abteilungen/industrial/dokumente/ downloads/veroeffentlichungen/forschungsergebnisse/euf-buergen-abschlussbericht-online.pdf).

area is small. An already advanced expansion of wind energy also increases the load factor.

The "uniformly distributed" scenario examined how a uniform load factor affects the expansion of wind energy and grid expansion requirements. In line with NEP scenario B 2030 of the NEP 2017-2030, the installed capacity of wind onshore turbines was set at 61 GW, which corresponds to a power generation of 125 TWh. For an equal distribution of load, the load factor is 0.8 inhabitants / km2 (Koch et al. 2018).

Figure 3-6: Wind power generation in the NEP B 2030 scenario (left) and its change in the scenarios "decentralized" (centre) and "uniformly distributed" (right)



Source: Öko-Institut, published in (Koch et al. 2018)

Figure 3-6 (right) illustrates district-specific wind power generation for scenario B 2030 of the NEP 2017-2030; expansion (76 TWh) was primarily in the northern and eastern federal states. The annual power generation scale ranges from 0.1 GWh (white) to >5 TWh (dark blue). Figure 3-6 (centre) represents the difference between the scenarios "uniformly distributed" and the NEP scenario. An unchanged power generation is displayed as a white area; a power generation reduced by 1 TWh is highlighted in red, an increased in blue. Wind power generation expansion of 52 TWh is redistributed structurally: the introduction of a single load factor will slow down wind-onshore development in the coastal regions of the North Sea and much of Lower Saxony in comparison to NEP scenario expectations, while expansion is accelerated in southern Germany and in the eastern parts of Mecklenburg-Western Pomerania. The driving force for accelerated expansion in southern Germany is the small number of wind turbines in a relevant potential area, while the impetus in Mecklenburg-Western Pomerania is low population density.

Due to the correlation of high population density and high demand, an equal distribution of the load would likely lead to a renewable energy development far from load centres. This becomes apparent when a change in the regionalization of the uniformly distributed scenario is compared with that of the decentralized scenario Figure 3-6 (right): In the "uniformly distributed" scenario, wind development in the Ruhr area is reduced compared to the NEP scenario; the "decentralized" scenario where renewables expansion is strictly oriented towards load proximity, there wind development is increased. The opposite effect can be observed in eastern Mecklenburg-Western Pomerania.

Table 3-3: Generation potential for onshore wind power in the scenarios NEP B 2030, "uniformly distributed" and "decentralized"

Federal state	Generation potential		
	NEP B 2030	uniformly distributed	decentralized
		TWh	
Schleswig-Holstein and Hamburg	19.9	5.3	8.7
Lower Saxony and Bremen	25.9	14.6	15.9
Subtotal North-West	*45.8*	*19.9*	*24.6*
Brandenburg and Berlin	15.0	14.8	8.3
Mecklenburg-Western Pomerania	10.8	14.3	3.1
Saxony-Anhalt	12.5	8.6	5.6
Subtotal North-East	*38.3*	*37.7*	*17.1*
North Rhine-Westhalia	11.4	3.7	26.1
Subtotal West	*11.4*	*3.7*	*26.1*
Hesse	4.0	6.1	7.8
Subtotal Central	*4.0*	*6.1*	*7.8*
Saxony	4.3	5.2	5.7
Thuringia	4.6	5.6	2.8
Subtotal South-East	*8.9*	*10.8*	*8,5*
Rheinland-Palatinate	7.8	7.3	7.1
Baden-Wuerttemberg	3.4	8.5	11.6
Bavaria	4.8	30.8	20.6
Saarland	0.9	0.6	2.0
Subtotal South	*16.9*	*47.2*	*41.3*
Total Germany	152.4	152.4	152.4

Source: Öko-Institut, published in (Koch et al. 2018)

Table 3-3 presents corresponding generation data for the NEP B 2030 three "uniformly distributed" scenarios and "decentralized" at the aggregation level of the federal states, and the zones defined for comparison in this study.

3.5. Preliminary conclusion

The small-scale analyses of electricity demand and variably-defined potential assumptions for wind and solar power generation, i.e. at district level, show first of all that the distribution patterns of all three categories under consideration differ greatly and for Germany overlap only by way of exception in Germany:

- total power consumption is concentrated on a relatively large scale in the industrial regions of western Germany and Baden-Württemberg; there is high demand in the major cities adjacent to them or the metropolitan regions surrounding them;

- the potential of high-yield solar power generation is concentrated above all in Bavaria, the western parts of Baden-Württemberg and metropolitan regions with a substantial supply of photovoltaic roof space.
- Wind generation potential is concentrated above all in the northern regions of Germany and a considerable part of the districts located in central Germany.

Consistent cellular concepts (at district level) could thereby only allow implementation with additional options. Large-volume electricity storage would be indispensable for all variants. Additional flexibility options would either be available at relatively low cost, but at the same time associated with CO_2 emissions (natural gas-based power generation, possibly combined with power-to-heat solutions). Or they would have to focus on CO_2-neutral fuels produced beyond cell boundaries, which leaves many aspects (technology, resources, infrastructures) unresolved, but which in any case would involve comparatively high conversion losses, thus higher resource and land consumption, as well as high costs – even with significant cost reductions.

The larger the cells are defined, the greater the effect diversification has. The need for flexibility options, energy losses, resource and land use would decrease and, as a result, associated costs. Even with very large cuts in cellular approaches, it must be assumed that, regardless of the technological prerequisites and the costs involved, transregional exchange would occur to a considerable extent.

The different implications become even more pronounced if, in a next stage, not only the theoretical potential for renewable energy power generation but also other spatial and moderate regulatory restrictions – and thus a "realistic" potential – are taken into account.[10]

- The potential for onshore wind energy here is reduced by roughly 86% throughout Germany;
- the corresponding potential decreases by 62% to 93% in the different zones;
- if we consider the (territorial) federal states, the exploitable potential is reduced by 33-95%.

No numerical estimates are available for ground-mounted photovoltaic systems, which account for about one third of the potential of solar power generation, but here, too, corresponding limitations can be assumed.

Beyond the limits of potentials in terms of area and regulations, acceptance limits are particularly relevant for the utilization of onshore wind power. Acceptance is not a static limiting factor and can be influenced by suitable procedures and compensation measures of various kinds. The differences between a strictly demand-oriented localization of wind turbines ("decentralized" scenario) and an equal distribution of the regional load ("uniformly distributed" scenario) show the scope in which questions of acceptance could influence the spatial distribution of the generation potentials that can be tapped.

[10] This does not yet include very restrictive distance regulations, etc., but rather experience gained to date from approval procedures in which only parts of the areas applied for are made accessible for wind power generation.

In conclusion, it should be noted that the imbalances shown between demand and the potential supply of renewables will become even more pronounced after 2030 if overall electricity demand continues to increase as a result of new demand (sector integration).

4. Analysis of present quantitative studies

4.1. Overview

Based on the qualitative preliminary considerations and the estimation of the potential limits in their spatial distribution, 10 modelling studies were more closely investigated, whereby spatially differentiated analyses were carried out and, where applicable, conclusions drawn concerning network expansion:

1. Öko-Institut, Prognos: Electricity System 2035 (on behalf of the WWF), 2018 (Öko-Institut & Prognos 2018)
2. Öko-Institut: Networks Transparency (funded by BMBF), 2018 (Öko-Institut 2018)
3. Friedrich-Alexander Universität Erlangen-Nürnberg: Regional Considerations in Renewables Funding (on behalf of the Monopolies Commission), 2017 (FAU 2017)
4. Fraunhofer Institut für System- und Innovationsforschung, Consentec, Institut für Energie- und Umweltforschung Heidelberg, Technische Universität Wien, M-Five, TEP Energy: Long-term scenarios (on behalf of BMWi), 2017 (Fraunhofer ISI et al. 2017)
5. E-Bridge, Prognos, RWTH Aachen, Forschungsgemeinschaft für elektrische Anlagen und Stromwirtschaft: Energy transition – Outlook 2035 (on behalf of 50 Hertz Transmission), 2016 (E-Bridge et al. 2016)
6. Consentec: Network/Grid Stress Test (on behalf of TenneT TSO), 2016 (Consentec 2016)
7. Prognos, Friedrich-Alexander Universität Erlangen-Nürnberg: Decentralization and Cellular Optimization (on behalf of N-ERGIE), 2016 (Prognos & FAU 2016)
8. Egerer, J., Weibezahn, J., Hermann, H.: Two Price Zones for the German Electricity Market – Market Implications and Distributional Effects, 2015 (Egerer et al. 2015)
9. Verband der Elektrotechnik Elektronik Informationstechnik/Energietechnische Gesellschaft: The Cellular Approach, 2015 (VDE/ETG 2015)
10. Reiner Lemoine Institut: [Comparison and Optimization of Centralized and Decentralized Expansion Paths to a Power Supply from Renewables in Germany (on behalf of the Haleakala-Stiftung, 100 prozent erneuerbar stiftung, Bundesverband mittelständische Wirtschaft (BVMW)), 2013 (RLI 2013)

In the modelling studies where complete and consistent comparison for documentation purposes was not possible, most editors or clients provided suitable supplementary data material. The editors of the following study were unable or unwilling to supply the additional data required:

11. Friedrich-Alexander Universität Erlangen-Nürnberg: Regional Price Components in the Electricity Market (on behalf of the Monopolies Commission), 2015 (FAU 2015)

With these 10 adequately documented modelling studies, a total of 28 scenarios were available for different forms of the German electricity system, from which conclusions regarding grid expansion requirements can also be drawn.

As the common and comparable distinguishing features of the different studies and scenarios can be seen primarily as exogenous and endogenous regionalization models of the different power plant capacities, the following is an initial approximation of the different regionalization patterns for decentralization.

4.2. Different modeling approaches

Some studies included in the metastudy differ considerably in the modelling approach used. This makes comparison of the quantitative results difficult. To evaluate the studies, types were introduced for the different modelling approaches which will be discussed here.

A key criterion for differentiation is the inclusion of investments. Short-term electricity market models do not take investments into account; in the case of investment models, for example, the installed generation capacities, based on renewables and grid expansion requirement can result in endogenous model optimization. Most short-term electricity market models make an initial assumption here.

When determining the investment requirement, a method can also be used that focusses not so much on an optimal investment result but rather an acceptable one, through downstream extension of an investment option. This procedure plays a part particularly in determining the grid expansion requirement and is used by the transmission system operators in the grid development plan, for example: in order to eliminate any congestion of the transmission grid resulting from market simulation, grid expansion measures are added in an iterative procedure until the congestion falls within an acceptable range. This means that the network expansion option does not compete with other investment options, such as variation in the regional distribution of renewable energy plants. These multi-stage procedures are referred to here as iterative network expansion planning.

The choice between an iterative grid expansion plan and an endogenous model investment decision is accompanied by detailed mapping of the electricity grid, which represents a further differentiation criterion between the modelling approaches. Zone models are used in particular when an endogenous model investment decision is made; network node models can be selected for iterative network expansion planning. The load flow can be non-simplified (non-linear) or simplified (linear approximated). The former is called AC load flow simulation, the latter, usually, DC load flow simulation.

Many of the studies under observation are based on an optimization model. These minimize the costs taken into account in the model or maximize the welfare of society. The latter are referred to as equilibrium models.

Some studies do not use an optimization model but make regional accounting adjustments. An example of this is the mains stress test, which is based on the market results of the Grid Development Plan [NEP] 2025.

As a final differentiation criterion, a distinction can be drawn between single-stage and multi-stage procedures. As in the example already mentioned, an endogenous investment model usually represents a one-step procedure, while an iterative network expansion plan has at least two stages. The modelling approach in the long-term scenarios is a relatively complex multi-stage process in which an endogenous model investment decision is made before the next stage, where a detailed load flow simulation is carried out to verify and/or supplement the specific network expansion requirement. In the Öko-Institut‘s Decentral scenario, the generation units of a decentralized unit are given priority before switching to a higher aggregation level. This, too, represents a multi-stage process and differs from modelling which assumes central market logic.

These distinguishing features are dealt with in the short descriptions under the heading “Analysis approach and methodology”.

4.3. Different approaches to regionalization

Another distinguishing feature of the individual studies is the logic with which extensions to power generation plants based on renewables are built. It can be model-based or acceptance-based in practice. Since the distribution of renewable generation plants has a significant influence on the defined grid expansion requirement, this point is discussed in the brief descriptions under the heading "Regionalization approach / Expansion of renewables". This section introduces the relevant categories used in the short descriptions.

As discussed in section 3, the expansion of renewables is governed by potential limits. These are taken into account in all the studies; however, assumptions about existing potentials may vary.

In some studies, regenerative production volume or output is specified exogenously regarding both technological composition and regional distribution. In other studies, this is carried out endogenously within the modelling, or upstream.

Many studies in which decentralized power systems are to be mapped assume a near-load extension of the renewable generation plants. This is in contrast to the expansion of renewable capacities, which is defined by the assumption of maximizing energy yields with output remaining constant (profit-maximizing expansion of renewables). Optimum minimization of investment requirements and other costs plays a part in endogenous, cost-optimized renewables expansion.

4.4. Brief descriptions of the studies and scenarios

The evaluation of the above-mentioned investigations and scenarios is carried out using a uniform analysis grid:

1. In the section "Analysis approach and methodology" the modelling approach used in the respective studies is described and compared with the other studies through the introduction of uniform terms. This is explained in section 4.2.
2. The section "Decentralization approach" describes the basic concept of decentralization as used in the study and whether a decentralized scenario is based on assumptions about input parameters, technical model implementations or the modelling result.
3. The scenarios from the studies under observation in the meta-analysis are described in brief in the section "Scenarios considered".
4. How, and on what methodological basis the spatial expansion structures of the electricity generation capacities of renewables are determined is documented in the section "Regionalization approach / expansion of renewables".
5. The key results shown for the purpose of the comparative analysis are documented under two different headings:
    - The section entitled "Overall system" contains information documented in the studies on system costs, efficiency gains, exchange relationships with other countries, etc. The range and the completeness of the information available vary considerably here.
    - The section "Grid expansion requirement" contains quantitative and qualitative information on the determined (or assumed) grid expansion requirement. Unfortunately, it should be noted that there are variations in the metrics in which quantitative network expansion requirements are reported.

Sections 4.2 and 4.3 deal with the modelling approaches used and give an overview of the different regionalization approaches.

Authors: Öko-Institut, Prognos

WWF Electricity System 2035+ (2018)

On behalf of: WWF

Analysis approach and methodology

The **short-term variable electricity generation costs** of the entire ENTSO-E system focusing on Germany are **minimized** using an **optimization model**, taking into account various technical and economic restrictions (**short-term electricity market model**).

The German extra-high voltage grid is mapped to **network nodes with individual HöS lines** (**DC load-flow model**); various flexibility options (DSM, electromobility, PtX) can be used to increase the integration of renewables; maximum annual CO_2 emissions are specified as a limit. There is no endogenous model investment decision for renewables or grid expansion. **Iterative network expansion planning** based on the TSO procedure is used to assess the network expansion requirement. Since the resultant load-flow and the iterative network expansion planning are calculated according to the market model, this is a **multi-stage modeling**.

Decentralization concept

In the project, the “Focus on Solar” scenarios can be interpreted as somewhat decentralized scenarios: decentralization is depicted as substitution of wind onshore systems remote from load with PV house roof systems positioned on private homes, which are equipped with decentralized storage for optimizing self-consumption.

Hence the decentralization approach is purely **assumptions-based** and focuses on the expansion of renewables.

Considered scenarios

Two sets of scenarios for the period 2020 - 2050 were studied, based on the transformation scenario of part 1 of the project: both sets of scenarios represent a coal phase-out scenario in line with the Paris objectives. The data set for the BAU scenario assumes an expansion of renewables which continues to focus strongly on wind-onshore expansion. The "Focus on Solar" set gives preference to PV expansion with a high proportion of PV self-consumption storage.

Both scenarios with the scenario years 2025 and 2030 are included in the meta-analysis.

Scenario	Wind in GW	PV in GW
BAU 2025	67	75
BAU 2030	80	87
Focus on Solar 2025	65	75
Focus on Solar 2030	65	116

Regionalization approach/ Expansion of renewables

In the “Focus on Solar” scenario, the construction of additional renewable electricity generation plants is based on the criterion of **load proximity** and, in the reference scenario, on the criterion of **yield maximization**. Both the **technological** and **regional distribution** at district level is specified **exogenously**, taking into account land availability.

Key results

a) Overall system

As yet, investigations have not been finalised conclusively. Detailed results on system costs and electricity exchange with foreign countries were not available for the present comparison.

b) Network expansion requirement

Looking ahead to 2050, the results of the model calculations to date show that the lines proposed within the framework of NEP 2025 are relevant for a system with a high proportion of renewable energy, irrespective of the chosen technology and regional distribution.

Renewable energy expansion focussing on PV and an increase in the share of PV self-consumption can slightly reduce, but under no circumstances replace, grid expansion requirement compared to more wind-focused renewable energy expansion.

Author: Öko-Institut

Increasing Transparency on Electricity Transmission Networks Expansion Requirement (“Networks Transparency”) (2018)

On behalf of: Bundesministerium für Bildung und Forschung

Analysis approach and methodology

The **short-term variable electricity generation costs** of the entire ENTSO-E system as applied to Germany are **minimized** using an **optimization model**, taking into account various technical and economic restrictions (**short-term electricity market model**).

The German extra-high voltage grid is mapped to **network nodes with individual HöS lines (DC load flow model);** various flexibility options (DSM, electromobility, PtX) can be used to increase the integration of renewables; the maximum annual CO_2 emissions are specified as a limit. There is no endogenous model investment decision for renewables or grid expansion. **Iterative network expansion planning** based on the TSO procedure is used to assess the network expansion requirement. Since the resultant load-flow and the iterative network expansion planning are calculated according to the market model, this is a **multi-stage modeling**.

Decentralization concept

In the "Decentral" scenario, decentralization is represented by the **modeling approach as a regional generation priority**. It is optimized in several stages: Stage 1 aims to cover the load at government district level with the existing generation supply. Electricity exchange with neighbouring units is not allowed for. In stage 2, the remaining unsecured load is covered by available surplus from other administrative districts at state level. Not until stage 3 is the residue in the ENTSO-E network covered.

In both the scenarios under consideration, decentralization is represented on an **assumption-based** basis by an extremely close-to-load RE distribution. PV systems are partially equipped with decentralized storage facilities.

Considered scenarios

The meta-analysis looks at two of the 10 scenarios developed in a stakeholder process with a decentralized component: "Decentral" and "85% RE". Both are assigned to the scenario year 2030, whereby the scenario "85% RE" also functions as a long-term scenario. Both scenarios assume a coal phase-out; this has already been completed in the "85% RE" scenario. The exogenously specified renewable energy production volumes and installed renewable energy output also vary accordingly:

Scenario	Wind in GW	PV in GW
85% RE	135	96
Decentral	77	53

The "85% RE" scenario follows central market logic, the “Decentral” scenario is calculated in the regional cascade procedure described above.

Regionalization approach/ expansion of renewables

The nationwide renewable generation capacities and volumes are **acceptance-based**. The construction of new plants based on renewables is in accordance with the criterion of **load proximity**: in both scenarios, an **upstream optimization** is carried out in which, in order to minimise the residual load, the optimum subdivision into wind, onshore / PV and regional distribution to the Federal states is determined, taking into account the **theoretical potential limits**. The resultant distribution of regenerative generation plants outcomes differs greatly from previous acceptance experiences and current expansion expectations.

Key results

a) Overall system

Compared to the NEP scenario B 2030, the "85% RE" scenario shows lower variable electricity generation costs (-14%) and significantly lower CO_2 emissions (-20%) due to the high proportion of renewable energy. The "Decentral" scenario shows approx. 20% higher variable electricity generation costs in Germany due to the decentralized generation priority, despite the higher proportion of renewables. CO_2 emissions can be significantly reduced as required. The total costs of the production system, taking into account the investment requirements, were not determined in this study.

In both scenarios, the requirement for near-load expansion of renewable generation plants leads to very high concentrations of renewable plants in the vicinity of the load centres. It seems doubtful whether such a development could be in place in the affected regions by 2030.

b) Network expansion requirement

The "85% RE" scenario requires no more network expansion than is calculated in NEP scenario B 2030. The "Decentral" scenario requires significantly less network expansion. In both scenarios, grid expansion requirements are saved due to the strictly near-load expansion of renewables and the coal phase-out. The influence of decentralized market logic on network expansion requirements was not investigated.

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LONG-TERM SCENARIOS FOR TRANSFORMATION OF THE ENERGY SYSTEM IN GERMANY – MODULE 4: "LOW EXPANSION OF TRANSITION NETWORKS" SCENARIO (2018)

On behalf of: Bundesministerium für Wirtschaft und Energie (German Ministry for Economic Affairs and Energy)

Analysis approach and methodology

Using an **optimization model**, the **entire system costs** of European power generation are **minimized**, taking into account various technical and economic restrictions. With the **investment model**, an endogenous model investment decision is made for renewables and conventional power plants. The network exchange capacities with other countries are considered in an **iterative process**. Various flexibility options (DSM, electric mobility, heat pumps) can be used to increase renewable energy integration.

The **modeling** is **multi-level**. Market modelling is followed by **endogenous model network expansion planning,** which determines the network expansion requirements of the extra-high voltage grid. In this model, the German extra-high voltage grid is mapped to **network nodes using individual EHV lines** (**AC or DC load flow model**).

Decentralization concept

None of the scenarios under consideration in this study is described by the authors as a decentralized scenario. Hence, there is no explicit concept of decentralization. The geNA (Low grid expansion) scenario can be interpreted as a decentralized scenario, since network bottlenecks lead to redispatch and thus to more regional generation. Hence the decentralized concept is **results-based**.

Considered Scenarios

The scenarios under consideration indicate a 50% share of renewables in gross electricity consumption in 2030.

Basis scenario	In this key target scenario of the study, the Federal Government's energy and climate policy goals are reached cost-effectively. In the case of the grid, this is achieved using established technologies (grid expansion).
Low grid expansion (geNA)	Analysis of the consequences of delayed network expansion: foregoing 21,000 line kilometres compared to the "Basis scenario". Only projects already defined by law are implemented. Network expansion is only possible to maintain and increase existing load flows (line replacement).

Regionalization approach/ Expansion of renewables

Regional distribution and **technological composition** of renewables relevant to expansion are determined using **endogenous models**. This means that the expansion of renewables is decided on the premise of **cost-optimality**. The achievable share of renewables in gross electricity generation is exogenously specified. Potential limits are taken into account.

Key results

a) Overall system

Energy and climate goals can be achieved without compromising system reliability even when grid expansion delays occur.

Since an interregional balance of renewable generation supply, electricity demand and foreign import of low CO_2 electricity is only possible to a limited extent in a scenario with delayed grid expansion, the delay in maintaining the energy and climate targets leads to a higher expansion of renewables (especially wind onshore). This results in an increase in costs at the overall system level: the costs of CO_2 avoidance double in the Low grid expansion (geNA) scenario. In order to reduce the CO_2 emissions of the heating sector, for example, the Low grid expansion scenario already uses the increased regional renewable energy surpluses in electrode boilers.

The costs for investments and operation of the power plants for the Low grid expansion and Basis scenarios are shown in the following table. Costs for the import and export of electricity are not taken into account, as these are difficult to represent.

m. €	2020	2030	2040	2050
Basis	41.905	50.630	47.432	51.285
geNA	49.555	44.718	41.007	42.084

b) Network expansion requirement

Measures to strengthen the networks will also be required in the event of stagnating network expansion. If grid expansion costs are saved in the transmission grid, they will be of a similar magnitude when the distribution grid is expanded.

In order to make the expansion of renewables cost-efficient, particularly profitable regenerative locations should be developed through grid expansion.

The costs for investments in transmission and distribution grids for the Basis scenario are shown in the following table:

m. €	2020	2030	2040	2050
Transmission grid	2.725	2.577	2.496	2.464
Distribution grid	16.290	17.353	17.879	21.290

The costs for investments in transmission and distribution grids for the Low grid expansion (geNA) scenario are shown in the following table:

m. €	2020	2030	2040	2050
Transmission grid	3.172	4.161	4.254	4.333
Distribution grid	17.582	17.601	19.931	22.800

Author: Friedrich-Alexander Universität Erlangen-Nürnberg

Regional Considerations in Renewables Funding (2017)

On behalf of: Monopolkommission (Monopoly Commission)

Analysis approach and methodology

Using a **welfare maximizing optimization model**, the study assesses the effect of different renewable subsidy approaches on the subsidy costs of renewables, system efficiency and the necessary expansion of pipelines. The market designs (market equilibrium, nodal price system) and various flexibility options vary.

It is an **investment model**: the investment decision regarding the expansion of renewable generation plants, conventional power plants and DC corridors is made on the basis of an endogenous model.

The modeling is **one-step**: although it is divided into two sub-categories, the optimization problem is solved in one step.

The German extra-high voltage grid is aggregated using a **zone model**: 16 zones are introduced, connected to each other with **aggregated lines** (**DC load flow model**).

Decentralization concept

In this project, the term decentralized solution is used when network expansion is saved compared to the Grid Development Plan (NEP) reference scenario. Forgoing grid expansion can be compensated by a more load-based distribution of renewables (assumption-based or results-based), redispatch (results-based) or control of power generation on the basis of renewables (results-based).

Considered Scenarios

A total of 16 scenarios were considered, combined in the following scenario characteristics and regionalization approaches for renewables.

The share of renewables is ~56% gross electricity consumption in 2035.

ME optimization in market equilibrium alongside today's framework conditions.

FB First Best benchmark through optimization in a nodal price system.

RD Network expansion planning takes into account that network bottlenecks can also be solved by using redispatch.

SA A systemic regulation (SA*) only takes place if negative prices occur in the electricity market.

SA* Redispatch and the system-oriented control of renewables is taken into account in grid expansion planning.

Regionalization approach/ expansion of renewables

The study explores different regional distributions and technological compositions of renewables. **Depending on the scenario**, **technological composition** and **regional distribution** are determined either exogenously or endogenously. On the other hand, the level of total generation from renewables, which corresponds to scenario B 2035 of the NEP 2017-2030, is assumption-based throughout. Renewable energy expansion will be carried out under the premise of **cost-optimality**. The **potential limits** are taken into account.

NEP (Grid Development Plan) Technological composition and regional distribution are **specified exogenously** as allocation according to scenario B 2035 of the NEP 2017-2030.

UNIV The technological composition and regional distribution of renewable energy is an optimization result **determined by modelling**, based on the assumption that a uniform funding rate exists (**UNIV**).

OPT1 The technological composition and regional distribution of renewables is an optimization result **determined by modelling** in a nodal price system (**FB** scenario). No renewables control.

OPT2 According to **OPT1** with renewables control.

OPT3 The **regional distribution** of renewables is the only optimization result **determined by modelling** in a nodal price system (**FB** scenario). The **technology-specific** generation mix of renewables is **specified exogenously** and corresponds to that of the **NEP** scenario. Renewables are curtailed.

Key results

a) Overall system

Efficiency gains can be achieved by (in ascending order):

- Distribution according to a uniform funding rate
- system-oriented control and redispatch in combination (substituting network expansion)
- a "decentralized settlement of renewable energy plants" (but with higher CO_2 emissions)

The efficiency gains in relation to welfare of the reference scenario MGNEP (€ 28,420 million) of the different scenarios are shown in the following table.

Efficiency gains in m. €	MG	FB
NEP	0%	5%
NEP&SA	2%	7%
NEP&RD	0%	
NEP&SA*	2%	
NEP&SA&RD	4%	
UNIV	2%	
OPT1	9%	14%
OPT1&RD	10%	
OPT2&SA	11%	16%
OPT2&SA&RD	12%	
OPT3&SA		11%
OPT3&SA&RD	7%	

b) Grid expansion requirement

A reduction of the HVDC expansion is possible particularly through alternative close-to-load distribution of renewables. The combination of redispatch and system-related control also saves on network expansion requirements.

The following table lists the line requirements of the scenarios under consideration.

No. of DC corridors	MG	FB
NEP	15	9
NEP&SA	15	5
NEP&RD	14	
NEP&SA*	14	
NEP&SA&RD	11	
UNIV	15	
OPT1	7	0
OPT1&RD	6	
OPT2&SA	7	0
OPT2&SA&RD	6	
OPT3&SA		3
OPT3&SA&RD	8	

Authors: Prognos, Friedrich-Alexander Universität Erlangen-Nürnberg

DECENTRALIZATION AND CELLULAR OPTIMIZATION – EFFECTS ON GRID EXPANSION REQUIREMENTS (2016)

On behalf of: N-ERGIE

Analysis approach and methodology

The necessary level of generation, consumption and grid capacity required in the context of the energy transition is analysed using the **welfare maximizing optimization model**. The influence of flexibility options (feed-in management, redispatch, DSM, CHP, heat pumps, PV batteries) on grid expansion was considered under various framework conditions.

Regardless of the scenario, the **investment model** is used to make an investment decision regarding the extension of DC corridors. Depending on the scenario, network expansion can also compete with the investment option in renewable energy expansion or decentralized CHP plants.

It is more like a **one-step modelling**: The optimization problem has a closed-form solution, although it is divided into two partial problems.

The German extra-high voltage grid is aggregated using a **zone model**: 16 zones are introduced, which are connected to each other by **aggregated lines** (**DC load flow model**).

The share of renewables in gross electricity consumption is ~60%.

Decentralization concept

In this project, the term decentralized solution is used when network expansion is saved compared to the NEP reference scenario. Relinquishing grid expansion can be compensated for by closer-to-load distribution of renewables (assumption-based or results-based), redispatch (results-based) or control of power generation on the basis of renewables (results-based).

Considered scenarios

ME	Optimization in market equilibrium (**ME**) with optimization in market equilibrium in today's context.
FB	First Best (**FB**) benchmark through optimization in a nodal price system.
FM&RD	In the electricity market, feed-in management (**FM**) takes place at negative prices. Network bottlenecks may be relieved by redispatch (**RD**), thus redispatch costs compete against investments in network expansion.
CHP(KWK)	An extension of CHP power plants in the southern Federal states is assumed.

P2G	Power-to-gas plants are used in regions with high electricity production. An additional variant, P2Gnorth, considers expansion especially in northern German states.
HP(WP)	Disproportionately high number of heat pumps in northern Germany.
EV	Increased number of PV battery systems to cover own needs in the southern Federal states (Baden-Württemberg, Bavaria, Rhineland-Palatinate, Saarland).

Regionalization approach/ expansion of renewables

Within the scope of the study, the **regional distribution** of renewables aiming towards **maximization of earnings** (**ME**) changes to **decentralized** (**RE**) in order to highlight the system optimum from a cost perspective. Both the **technological composition** and the **regional distribution** are determined on an **endogenous model** basis in the renewable energy scenarios. The potential limits are taken into account.

ME	The distribution of renewable energy plants corresponds to the distribution of scenario B2035 of NEP 2025.
RE	The regional distribution of renewable energy expansion is the result of a balance between extensive network expansion in RE expansion at profitable locations and low network expansion at locations creating lower revenue for RE plants.
REh	Analogous to scenario RE with the variation that a less dramatic decline in PV systems costs is assumed.

Key results

a) Overall system

Efficiency gains can be achieved by (in ascending order):

- feed-in management, redispatch and optimized distribution of renewables given current conditions
- introduction of the nodal price system

If they are approved as alternative measures for grid expansion, the feed-in management and redispatch options have a high savings potential with regard to grid expansion requirements. Likewise, a shift of renewable generation in southern Germany in conjunction with feed-in management can produce sizeable effects.

The efficiency gains in relation to the welfare of the MG_{NEP} reference scenario (€26,931 million) of the different scenarios are shown in the following table:

Efficiency gains	MG	FB
[simple]	0	2%
RE	1%	5%
EM		6%
EM&RD	5%	

RE&EM		11%
RE&EM&RD	6%	
REh&EM&RD	6%	
ALL	6%	11%

b) Grid expansion requirement

The use of the flexibility options under consideration can reduce the HVDC network expansion requirement in the market equilibrium scenarios from 14 to 8 HVDC lines. The introduction of a nodal pricing system instead of the central market offers further potential for reducing network expansion requirements.

The necessary network expansion of the individual scenarios is listed in the following table.

No. of DC corridors	MG	FB
[simple]	14	8
RE	13	1
EM		5
EM&RD	8	
RE&EM		1
RE&EM&RD	8	
REh&EM&RD	8	

Authors: E-Bridge consulting, Prognos, RWTH Aachen, Forschungsgemeinschaft für elektrische Anlagen und Stromwirtschaft

ENERGY TRANSITION – OUTLOOK 2035 (2016)

On behalf of: 50Hertz Transmission

Analysis approach and methodology

Multi-level modeling is used to generate the scenario results in this project. In the first **optimization**, a simplified **investment model** is used to develop a cost-minimized **conventional power plant park** which guarantees supply reliability. This is included as a scenario assumption in the second modeling stage, the **short-term electricity market model**. In this optimization, **short-term variable power generation** costs are **minimized**.

Together with electricity demand, the resultant hourly power plant operations form the net node feed-ins with which impact the **European extra-high voltage grid node oriented mapping** at stage 3. The load flow is represented by an **AC load flow simulation**. **Iterative network expansion planning** is used to assess the need for network expansion.

Decentralization concept

In this study, the "Prosumer-oriented energy transition" scenario amounts to an **assumption-based** decentralized scenario. In this study, decentralization implies more consistent regional distribution of smaller renewable energy systems. In addition domestic households, which have been typically consumers of electricity, will increasingly become electricity producers. The "competitive energy transition" scenario can be interpreted as a key counter-proposal.

Considered scenarios

Five scenarios are developed which exceed the range of NEP scenarios ("extreme scenarios"). The aim of the project is to prove the effectiveness of the network expansion projects defined in the NEP along other development paths.

Three scenarios satisfy the climate policy objectives of the Federal Government with regard to the electricity sector (these are: Energy transition according to the EEG, Prosumer-oriented energy transition, Competitive energy transition). Two scenarios do not achieve the energy policy goals of the Federal government due to a lack of acceptance.

The scenarios under consideration indicate a share of 55-60% renewable energy in gross electricity consumption in 2035.

Prosumer oriented energy transition	The scenario has a stronger regional component: European balancing is not the main issue; there are a high number of small storage units in combination with photovoltaic systems. Sector integration and DSM are implemented.

Energy transition according to EEG expansion path	Achieves policy objectives by combining different generation technologies under the **EEG** (Renewable Energy Sources Act). Large and small plants are given equal funding.
Competitive energy transition	Technology-neutral tenders lead to prioritization of large wind farms and PV parks at high-yield locations.
Delayed energy transition	Political goals are delayed in their implementation due to a lack of acceptance. This scenario is based on the EEG expansion path but does not attain the German government's own energy policy goals.
Incomplete energy transition	Lack of acceptance prevents the achievement of political goals. The climate policy targets will clearly not be reached by 2050.

Regionalization approach / expansion of renewables

The **regional distribution** and **technological composition** of renewables are **specified exogenously**. The subject of the study is the premise under which renewables expansion takes place, and varies between the scenarios:

Prosumer oriented energy transition	The regional distribution is characterized by a **near-load extension**.
Energy transition according to EEG (Renewable Energy Sources Act) **expansion path**	Consumption-related renewable expansion (especially PV) is moderately robust (**limited near-load**).
Competitive energy transition	Expansion at profitable locations (**profit-maximizing**).
Delayed energy transition	Based on an EEG path, climate targets achieved with a time delay.
Incomplete energy transition	Based on competitive energy transition, climate targets not reached.

The potential limits are taken into account.

Key results

a) Overall system

Of the scenarios examined, the "Prosumer-oriented energy transition" shows the highest variable electricity generation costs. In this scenario, the renewables used can only make a small contribution to load coverage, so that gas power plants have comparatively high feed-ins. However, it is significant that the "Prosumer-oriented energy transition" scenario requires less investment in renewable energy systems than the "Competitive energy transition" scenario.

The costs of investment and operation of conventional and renewable power plants are shown in the following table.

Costs in m. €	Investment costs	Variable costs	Total
Prosumer oriented energy transition	141.5	16.9	158.4
Energy transition in EEG (Renewable Energy Sources Act) **expansion path**	162.8	14.9	177.7
Competitive energy transition	174.2	14.0	188.2
Delayed energy transition	136.6	12.2	148.8
Incomplete energy transition	86.5	13.6	100.1

b) Grid expansion requirement

The key result of the study is that the grid expansion requirement as defined in the NEP appears robust: regardless of further developments in the energy transition, a large part of the defined grid expansion requirement is necessary, independently of the scenario. The "Competitive **energy transition**" scenario has a higher need for grid expansion than the "Prosumer-oriented **energy transition**" scenario; the energy transition scenarios have a higher need for grid expansion than the scenarios that do not meet the climate targets of the Federal Government. Wind turbines are identified as a major driving force behind grid expansion requirements.

The scenario-dependent network expansion requirement is specified in investment requirements here:

Scenario	Investment in m. € 2015-2025	2025-2035	Total
Prosumer oriented energy transition	24	5.5	29.5
Energy transition according to EEG (Renewable Energy Sources Act) **expansion path**	24	8.5	32.5
Competitive energy transition	24	10.9	34.9
Delayed energy transition	24	5.6	29.6

Incomplete energy transition	24	4.5	28.5

Author: Consentec

NETWORK STRESS TEST (2016)

On behalf of: TenneT TSO

Analysis approach and methodology

The analysis-oriented approach of this study is based on the calculations of the NEP 2025 for the scenario year 2035. Instead of an optimization model, a rough calculation or regional balancing is performed. By varying the installed capacity, assumptions are made about the effects on grid loads in selected hours. This is used to determine transport requirements between the North, Central and South regions.

Decentralization concept

In this study, decentralization is represented in the “Decentral" scenario by substituting load-distant wind onshore systems with PV house roof systems positioned on private homes. The rooftop systems are also equipped with decentralized storage systems for optimizing self-consumption.

The decentralization approach is thus purely **assumption-based** and focuses on the expansion of renewables.

Considered Scenarios

The aim of the project is to verify the robustness of the grid expansion requirements identified in the NEP 2025 for the scenario year 2035, even under altered conditions. The following scenarios were considered in this analysis:

DE 100% coal-free power	Phase out coal-fired power generation by 2035, the lost generation capacity will be replaced by wind onshore in the North.
Decentral	Focus on PV power generation instead of wind: 150 GW installed capacity in 2035 in combination with small storage facilities and e-mobility.
Flexibilization of Demand	Switchable loads, especially in surplus regions through flexibilization of industrial processes and power-to-heat.
Combined scenario	Combination of the above three scenarios.

Regionalization approach/ expansion of renewables

The origin of the study is the construction of new renewables for scenario B2035 of the NEP 2025. The technological composition and regional distribution vary depending on the scenario. The **exogenously specified** expansion of regenerative generation plants thus represents an initial assumption. The potential limits are taken into account.

The regionalization of scenario B2035 of the NEP 2025 varies according to the scenario.

DE 100% coal power free	Construction of 70% of the additional wind onshore turbines in Schleswig-Holstein, Lower Saxony and Mecklenburg-Western Pomerania and 30% in the rest of southern Germany (**profit-maximizing**).
Decentral	Substitution of the wind extension by PV: 70% of the wind extension reduction takes place in the north and 30% in the south of Germany (close-to-load).
Decentral I	80% of PV systems are distributed in Bavaria, Baden-Württemberg and the south of Rhineland-Palatinate and Hesse, and 20% in Mecklenburg-Western Pomerania, Brandenburg and Saxony.
Decentral II	PV systems are distributed according to roof area potential.
Flexibilization of Demand	The distribution of renewables is taken from scenario B 2035 of the NEP 2025 (**yield-maximizing**). The regional distribution of the flexibilization potential is shared among all Federal states which focus on wind energy surplus regions.
Combined scenario	The combination scenario is a combination of the 3 other scenarios. Here, NEP generation from coal-fired power plants is replaced by PV systems (distribution similar to Decentral I) (**close-to-load**).

Key results

a) Overall system

The study focuses exclusively on statements regarding network expansion requirement; further analyses were not carried out.

b) Grid expansion requirement

The grid expansion requirement identified in the NEP 2025 was found to be generally robust. Although the absolute need for investment in grid expansion projects remains constant, deviations from the necessary line expansion projects could exist, especially in the DE 100% coal-power free scenario. In the other scenarios, the grid expansion requirement might be reduced, but the grid expansion requirement identified by NEP 2025 for 2035 could then be used to integrate higher shares of renewables. In this study, the grid expansion requirement is derived from the following scenario-dependent transport requirements:

Scenario	Transport requirements in GW

	North-South[11]	Central-South[12]
DE 100% coal-free power	46.5	36.1
Decentral	13.9	24.9
Flexibilization of Demand	27.4	18.3
Combined scenario	28.8	20.5
NEP 2015 B 2035	31.8	33.7

[11] North-South: from Lower Saxony/Mecklenburg-Western Pomerania/Schleswig Holstein remainder to Bavaria/Baden-Württemberg/SaarlandRhineland-Palatinate

[12] Central-South: from North Rhine-Westphalia/Hessen/Thuringia/Saxony to Bavaria/Baden-Württemberg/Saarland

Author: VDE/ETG Taskforce

THE CELLULAR APPROACH (2015)

On behalf of: Verband der Elektrotechnik Elektronik und Informationstechnik

Analysis approach and methodology

The study has two parts. Both analysis approaches focus on **greenfield planning**. The question of which target situation would be optimal from the current viewpoint is separated from planning restrictions such as consideration of the existing infrastructure. Costs and investments are not included in either model.

In the first part, the extent to which specified functioning cells are able to provide a self-sufficient supply is investigated. The cells are equipped with generation units and storage capacity. Using standard load and generation profiles for typical weeks, a **balance sheet** is then drawn up to determine the resulting degree of self-sufficiency. The second part of the study aims to assess future grid expansion requirements among the Federal states[13]. An **optimization model** is used to **minimize the transport**[14] of **annual energy generation and demand** between regions. The individual regions are connected with potential transmission corridors hence this is a **zone model with aggregated potential lines**. The "energy flow" is mapped using the **transport model**.

The results of the first part of the study are not used as a basis for the second part. In this respect, the modeling is a **one-step** process.

Decentralization concept

The decentralization approach is **assumption-based** and **model-based**.

In the first part of the study, **assumption-based** decentralization is presented as a concept of functional cells (household, trade, industry) that meet their own energy requirements as independently as possible. With their remaining residue, these functional units can then merge to form the next higher grouping. These networks would then align themselves to local conditions and administrative levels, e.g. districts, counties, administrative districts. The choice of the auditing parameters (decentralized unit) should be interpreted as **model-based**.

In the second part of the study, decentralization is represented by the **modelling approach** as a **regional production priority at Federal level** by penalising access to production from other Federal states. In scenario B, decentralization is also represented based on an **assumption** of near-load distribution of renewables (cf. regionalization approach / expansion of renewables).

Considered Scenarios

[13] The city states are included in the neighbouring Federal states, the North Sea and the Baltic Sea form independent zones.

[14] The sum of transmitted energy and length for all corridors in minimized.

The two scenarios of part 2 were included in the evaluation of the metastudy. The scenarios (approach A and approach B) without a clear target year serve to determine the interzone energy transmission requirement depending on the regional distribution of renewable electricity generation. The absolute share of renewables in the energy supply does not vary and amounts to 87%.

Approach A Renewables expansion is focused on offshore wind farms (40 GW North Sea, 10 GW Baltic Sea).

Approach B Renewables expansion is focused on wind-onshore and PV systems; wind offshore is assumed to be 12.5 GW (10 GW North Sea, 2.5 GW Baltic Sea)

Regionalization approach/ expansion of renewables

In the scenarios, the technological composition and regional distribution of renewables at a broader Federal state level are specified exogenously. The potential limits are taken into account. The extension logic varies among the scenarios:

Approach A The regional distribution of renewable power generation options is characterized - given the high concentration of wind offshore plants - by a **yield-maximizing expansion**. The regionalization of wind onshore and PV systems corresponds to the distribution allocated to the regions in 2011, which also follows the principle of yield maximization.

Approach B The regional distribution of renewable power generation options is characterised by **near-load expansion**.

Key results

a) Overall system

The study focuses exclusively on power generation structures and their implications for grid expansion requirements.

b) Grid expansion requirement

Since complete regional balancing within the defined zones is not possible in either scenario, a transmission grid is required between most German states. The need for transmission is independent of the scenario, particularly along the North-South and East-West axes. The regional distribution of renewables has a large influence on the grid demand, measured in transmission demand and kilometres:

Scenario	Energy exchange requirement in TWh	Transmission requirement in TWh	Corridor length in km
Approach A	602	180	377
Approach B	394	64	145

Authors: Deutsches Institut für Wirtschaftsforschung, TU Berlin, Öko-Institut

Two Price Zones for the German Electricity Market – Market Implications and Distributional Effects (2015)

On behalf of: Stiftung Mercator

Analysis approach and methodology

The study is based on calculations using an **optimization model (short-term electricity market model**) in which the **variable costs of electricity generation** are **minimized**.

The modeling is **multi-level**. At the first stage, the electricity market result is determined. The second stage involves network modelling. In doing so, the extra-high voltage network with **nodes mapped with individual EHV lines** is regarded as a restriction. In the event of a bottleneck, redispatch occurs. The load flow is mapped using the **DC load flow model**.

Decentralization concept

The decentralized concept of this study is based on the introduction of nodal pricing and is therefore purely **model-based**. The two regions "North" and "South" operate as decentralized units. As soon as a grid bottleneck occurs between the regions, regional electricity prices move apart. This market-based management of grid bottlenecks creates a temporary and partial regional production priority.

Considered Scenarios

The aim of the study is to analyse the impact of the introduction of bidding zones in Germany. Various scenarios with two to four price zones were calculated for this purpose. This metastudy considers two scenarios that highlight the conflict between centralized ("2015 with network expansion") and decentralized ("2015") markets.

Regionalization approach/ expansion of renewables

Both the technological composition and the regional distribution of renewable power generation are **exogenously defined** in this study. The regionalization approach is based on historical developments or is updated in line with probable trends. This causes an expansion, according to the **yield-maximizing approach**. Regionalization is not varied between the scenarios. The potential limits are taken into account.

Key results

a) Overall system

In the "2015" scenario, electricity prices in the North and South zones only collapse for a few hours of the year. This will lead to slightly higher electricity prices in southern Germany and slightly lower electricity prices in the northern German electricity price zone. In order to compensate for the higher electricity prices in southern Germany, inter-connector earnings could be introduced and distributed accordingly. In addition, the introduction of two price zones could reduce the need for, and costs of, redispatch measures.

The total costs of the generation system (taking into account the investment requirements for the construction of new renewables and grids) were not determined in this study.

b) Grid expansion requirement

The study focuses primarily on electricity market effects and does not outline any grid expansion requirements.

Author: Reiner Lemoine Institut

COMPARISON AND OPTIMIZATION OF CENTRALLY AND DECENTRALLY ORIENTED EXPANSION PATHS FOR A RENEWABLE ENERGY POWER SUPPLY IN GERMANY,

On behalf of: Haleakala Stiftung, 100 prozent erneuerbar stiftung, Bundesverband mittelständische Wirtschaft

Analysis approach and methodology

The model used in the study is an **optimization model** that **minimizes electricity generation costs**. The necessary investments are included in the electricity generation costs. The **investment model** is defined as the economically ideal investment decision, balancing investments both in conventional and renewable capacity and in storage and grid expansion requirements. The German extra-high voltage grid is represented by a **zone model** at the wider Federal state level[15] (14 nodes). The lines running between the zones are **aggregated to paths**. There is no indication of how the load flow is mapped in the model. The optimization solution is closed in a **one-step** model.

Decentralization concept

The study shows the extent of the decentralization concept and concludes that in this study, the fuel type criterion (in the sense of promoting a CO_2 emission free power supply) is cited as a defining feature. In the "Decentral" scenario, however, the decentralized system is implemented through the expansion of renewables which is not based on electricity generation costs. An **assumption-based** decentralization approach is thus applied.

Considered Scenarios

The study considers an expansion of renewables towards a system with 100% renewables, taking into account the overall system costs. Depending on the scenario, a renewable energy share of 82-84% of the final energy consumption of the electricity sector will be achieved by 2030.

Scenario Central	There are no regional restrictions for the expansion of renewables, so expansion is controlled purely on the basis of cost-optimality criteria.
Scenario Decentral	The cost-optimality criterion for the expansion of renewables is limited by a regional minimum expansion target.
Scenario Offshore	The potential expansion of offshore wind farms is extended to 22.3 GW in 2030.

Regionalization approach/ expansion of renewables

Both the technological composition and the regional distribution of renewables have been **endogenously modelled** in this study. The regionalization approach thus represents a **cost-optimal** approach. In the decentralized scenario, the cost-optimized

15 The city states and Saarland are included in the neighbouring states, while the North Sea and the Baltic Sea form an independent zone.

solution is limited by a restriction that requires **higher load proximity**. The potential limits are taken into account.

Scenario Central	**Cost-optimal** without further restrictions
Scenario Decentral	60% of the renewable capacity extension determined in the “Central” scenario is maintained as a regional minimum and distributed by land surface (2/3 wind, 1/3 PV) and population (1/3 wind, 2/3 PV). A further criterion is the requirement that each region has a share of renewable energy in electricity generation amounting to at least 2/3 of the nationwide requirement. The remaining extension is optimized (**cost-optimal with load proximity target**).
Scenario Offshore	Offshore wind expansion is not optimized as is wind onshore and PV but taken from the lead study (29.5 GW to 2040, **cost-optimized with yield-maximizing target**).

Key results

a) Overall system

A comparison of the total system costs shows that there are no significant cost differences between the “Central”, “Decentral” and “Offshore” scenarios. Thus, from an economic perspective, any expansion path described is acceptable.

The following table shows the investment and operating costs in conventional and renewable power plants in 2020, 2030 and 2040:

m. €	Central	Decentral	Offshore
2020	45,897	46,444	45,929
2030	47,015	47,747	47,383
2040	48,641	48,782	48,081

b) Grid expansion requirement

The scenario-dependent distribution of renewables has a significant influence on grid expansion requirements. The “Offshore” scenario has the greatest need for grid expansion and will continue to do so, even after robust expansion, until 2030. The “Central” and “Decentral” scenarios initially continue to fall apart in 2030 but realign again by 2040 as the proportion of renewables increases. In 2030, the “Central” scenario has a higher transmission network requirement than the “Decentral” scenario.

GW	Central	Decentral	Offshore
2020	9.5	9.0	9.7
2030	20.3	16.5	36.3
2040	21.5	19.0	44.3

4.5. Comparison of regionalization approaches

Different regionalization approaches of the studies under consideration are compared based on the summary in the previous chapter:

- The comparisons are made depending on the support years used in the respective studies for 2030 and 2035. The assumptions and results of the VDE/ETG study, which refer to an unspecified but rather long-term horizon, are each presented separately.
- For the sake of clarity, the analyses were carried out at an aggregate level, where four different plant categories are distinguished. The "wind" category consists of wind turbines on land and at sea. Offshore wind turbines were allocated to the North-West (North Sea) and North-East (Baltic Sea) zones. The "photovoltaics" category includes roof-mounted and free-standing systems. The "coal" category comprises lignite and hard coal-fired power plants and "other" comprises gas-fired and biomass power plants.

On this basis, the regionalization approaches are presented in radar charts showing the total installed capacity of the individual scenarios for 6 zones (see section 3.2 and Table 3-1). Each of the defined zones is represented in the diagrams by an axis which is arranged evenly in a 360° circle around the 0-point. The values of the individual scenarios are joined with a line to enable comparison. With this form of diagram, different regionalization profiles can be well clarified.

The ranges of the regionalization approaches in particular are presented in the figures. In order to support the clarity and informative value of the illustrations, only a selection of the scenarios evaluated as a whole was presented in each case. On the one hand, those scenarios are shown which show a particularly characteristic distribution. On the other hand, groups of scenarios that follow a similar regionalization approach are each represented by only one scenario of the respective group.

Scenarios B 2030 and B 2035 of the NEP 2017-2030 (50Hertz et al. 2017) are shown as key comparative figures for the analysis years 2030 and 2035, since studies with the observation years 2030 and 2035 often refer to the network development plans.[16] The regionalization structures of the power plant fleet for 2016 are also shown in order to enable a comparison with the current situation. Finally, the theoretical potential limits for the technology categories wind and photovoltaics are also included (see Section 3.3).

For reasons of clarity, short titles have been assigned to the various studies or scenarios in order to make them recognizable in the illustrations. Table 4-1 below gives an overview of the short titles used.

[16] This reference is made to different editions of the grid development plans, but for reasons of clarity, all analyses are based on the 2017-2030 edition of the German Electricity Network Development Plan (NEP).

Table 4-1: List of short titles for the studies and scenarios

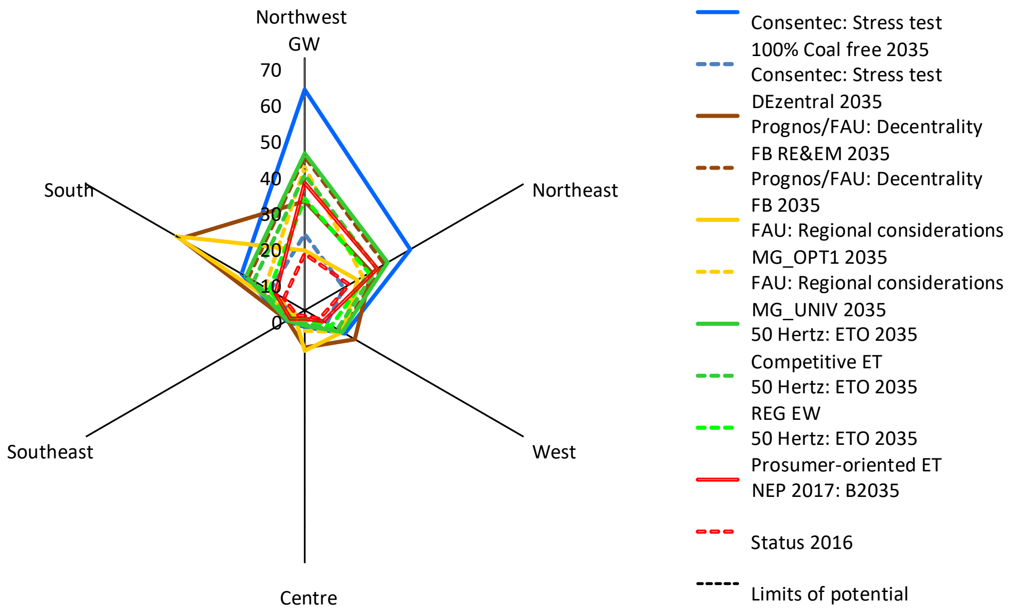
Scenario	Abbreviated title
Öko-Institut: Transparency of Electricity Networks, 2018	
85%	*OiI: Transparency of Electricity Networks 85% 2030*
Decentral	*OiI: Transparency of Electricity Networks, decentralized 2030*
Öko-Institut, Prognos: Electricity System 2035, 2018	
Reference 2030	*OiI/Prognos: WWF BAU 2030*
Reference 2035	*OiI/Prognos: WWF BAU 2035*
Focus PV 2030	*OiI/Prognos: WWF Focus PV 2030*
Focus PV 2035	*OiI/Prognos: WWF Focus PV 2035*
Fraunhofer ISI, Consentec, Ifeu, TUW, M-Five, TEP Energy: Long-term Scenarios, 2018	
Base scenario	*Fraunhofer ISI: LFS Basis 2030*
Low network expansion (geNA)	*Fraunhofer ISI: geNA 2030*
FAU: Regional Considerations in RE Funding, 2017	
MG_OPT1	*FAU: Regional considerations – MG_OPT1*
MG_UNIV	*FAU: Regional considerations – MG_UNIV*
E-Bridge, Prognos, RWTH Aachen, FGH: Energy Transition Outlook 2035, 2016	
Competitive energy transition	*50 Hertz: ETO 2035 Competitive ET*
Prosumer energy transition	*50 Hertz: ETO 2035 Pro-consumer ET*
REG energy transition	*50 Hertz: ETO 2035 REG ET*
Delayed energy transition	*50 Hertz: ETO 2035* energy transition *ET*
Prognos, FAU: Decentrality and Cellular Optimization, 2016	
MG	Prognos/*FAU:* Decentrality *MG*
FB RE&EM	Prognos/*FAU:* Decentrality *FB RE&EM*
Consentec: Network Stress Test, 2016	
100% coal free	*Consentec: Stress test – 100% coal free*
DEzentral	*Consentec: Stress test – DEzentral*
DEzentral (sensitivity)	*Consentec: Stress test – DEzentral (sensitivity)*
Combination scenario	*Consentec: Stress test – Combination scenario*
VDE/ETG: Cellular Approach, 2015	
Approach A	*VDE: ZA Approach A*
Approach B	*VDE: ZA Approach B*
Reiner Lemoine Institut (RLI): Comparison and Optimization of Centralized and Decentralized […], 2013	
Central	*RLI: Central 2030*
Decentral	*RLI: Decentral 2030*
Offshore	*RLI: Offshore 2030*
Electricity network development plan 2017-2030	
Scenario B 2030	*NEP 2017: 2030*
Scenario B 2035	*NEP 2017: 2035*
Situation as of 2016	Status 2016

Source: Öko-Institut

Figure 4-1 shows the regionalization approaches of different scenarios for the technology category wind in 2030. As can be clearly seen, the distribution so far and that assumed in the NEP is concentrated in the North-West and North-East zones. Most scenarios continue the development of the current regional distribution structurally; the regionalization profile remains largely unchanged.

Scenarios based on central control models or aiming at a cost-optimal expansion of wind energy (*RLI: Zentral 2030, Fraunhofer ISI: Basis 2030*[17]), concentrate the expansion of renewables on areas with high energy yields.

Figure 4-1: Regionalization approaches onshore and offshore wind, 2030



Source: Öko-Institut based on the aforementioned studies

For the *RLI: central 2030* scenario, the capacity level of wind power plants in 2030 is approximately 50% higher than that of the NEP, with large deviations between the regions. Assumptions for expansion are significantly stronger, especially for the South-East zone, where the NEP level is approximately 3.6 times higher, and for the West (factor 3.5), South (factor 1.7) and North-West (factor 1.4) zones.

The assumptions for wind energy capacity levels for the *Fraunhofer ISI: basis 2030* scenario are in total about 30% below the values taken into account in the NEP. However, the profiles for the wind power expansion differ in detail considerably from those of the NEP. A significantly stronger expansion occurs in the Central zone (by a factor of 1.3 compared to NEP). The wind power expansion is exceedingly below the assumptions of the NEP in the South zone (70% lower) as well as North-East and West (each 50% lower).

The scenarios primarily oriented towards load-related expansion strategies and avoidance of grid expansion (*Oil: Transparency of Electricity Networks Decentral 2030, RLI: Decentral 2030*) result in a much more regionally distributed expansion. In the *Oil: Transparency of Electricity Networks Decentral 2030* scenario, wind capacity in the North-East zone is around 50% below the NEP assumption. The main focus is on the expansion of wind energy in the southern zones (factor of 3.3 compared to the NEP in the *Oil:*

[17] The expansion profile for the Fraunhofer ISI: geNA 2030 scenario differs only slightly from the Basisszenario Fraunhofer ISI: Basis 2030 and hence is not depicted separately.

transparency of decentralized electricity grids in 2030 scenario, factor of 2.2 in the *RLI: Decentral 2030*, West (factor of 3 / 3.5), Central (factor of 2.6 / 2.4) and South-East (factor of 3 versus NEP only in *RLI: Decentral 2030* scenario).

The most distinguishing features of the *Fraunhofer ISI: geNA 2030* scenario, also with lower grid expansion, are a significant decrease in wind capacities in the Northwest zone (30% below the NEP value) and a significantly stronger expansion in the Central zone. The expansion level is 3.1 times higher than that of the NEP.

The stakeholder-defined scenario *OiI: Transparency of electricity grids 85% 2030* stands out in particular: here, a very high output at wind power plants and extremely near-load distribution are assumed. The reasons for the large deviation are the expansion target of 85% for renewable electricity generation brought forward to 2030 and the logic of expansion decisions based not on economic criteria but on the avoidance of inter-regional load compensation. A great expansion of wind power is assumed in the West and Central zones; in the South zone, too, the expansion potential of wind onshore turbines are heavily exploited. The resulting capacity levels: 5.5 (West), 4.6 (Central) and 6.2 (South) are higher than assumed in the NEP. In this respect, the question must be asked whether and, if so, for what time horizons the afore-mentioned levels of expansion could actually be achieved, taking restrictions more broadly into account. However, it should be noted that this scenario requires the grid expansion determined in the NEP for 2030, that is: it can also be seen as an indication for the grid expansion required in the longer term in any case.

In most scenarios, the theoretical potential far exceeds the envisaged installed performance. An exception is the scenario *OiI: transparency of electricity grids 85% 2030*, in which the (theoretical) potential is fully exploited in western Germany.[18] The potential for the year 2030 (chapters 3.3 and 3.4), subject to further restrictions, will be significantly exceeded in the scenarios with very strong wind power expansion in the West and South zones.

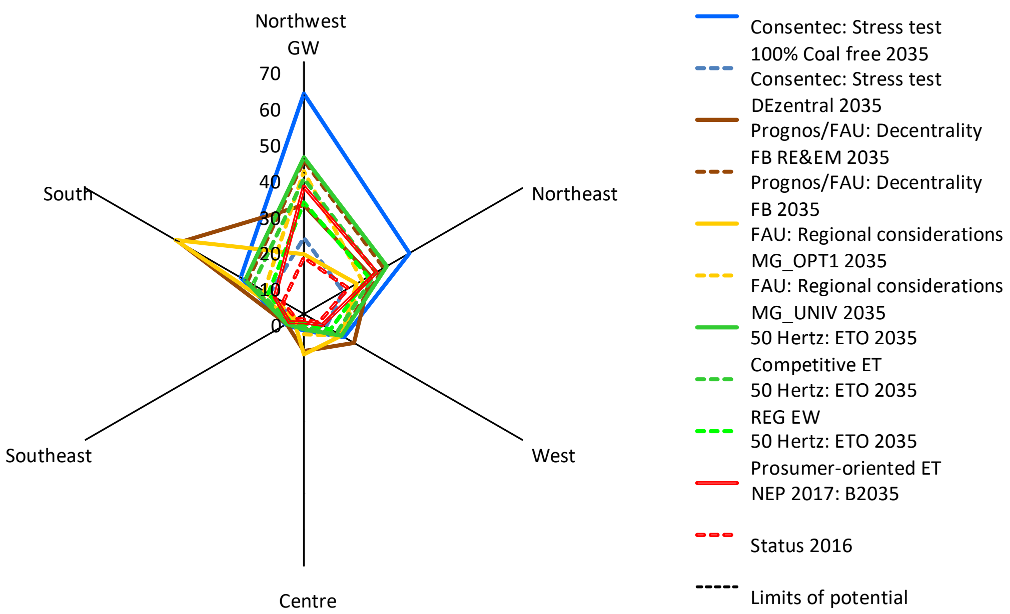
Figure 4-2 shows different approaches to regionalization in the technology category wind for 2035, with a large number of scenarios based on the current regional distribution or the regionalization approach of NEP Scenario B.

The *Consentec: Stress test - 100% carbon-free* scenario replaces coal-fired power plants with generation from wind onshore plants, a large percentage are to be built in the northern states. The capacities assumed in the NEP are exceeded by a factor of 1.7 to 2.2 in the North-West, North-East, West, Central and South zones.

The *Consentec: Stress test - decentral* scenario centres the expansion of renewables on generation from photovoltaic systems. However, since a total amount of renewable generation must not be exceeded in this scenario, the installed capacity of wind turbines has been reduced. In the North-West, North-East and South-East zones, wind turbine capacity levels are 30 to 50% below NEP scenario B assumptions for 2035.

[18] The potential limits used in this study are from the University of Flensburg and differ in part from the potential limits used in the “Networks Transparency“ project. For North Rhine-Westphalia, Öko-Institut has calculated a slightly higher potential limit than the University of Flensburg.

Figure 4-2: Regionalization approaches onshore and offshore wind, 2035



Source: Öko-Institut based on aforementioned studies

The *Prognos/FAU: Decentralization FB EE&EM* scenario, which is associated with significantly reduced grid expansion, concentrates the expansion of renewables on regions that are addressed by a nodal price system. This means that wind power is expanded, especially in areas where there is a high demand that cannot be fully covered by existing capacity. In the West zone, the NEP assumptions are exceeded by a factor of 2.7, in the Central zone by a factor of 4.5 and in the South zone by a factor of 4.3.

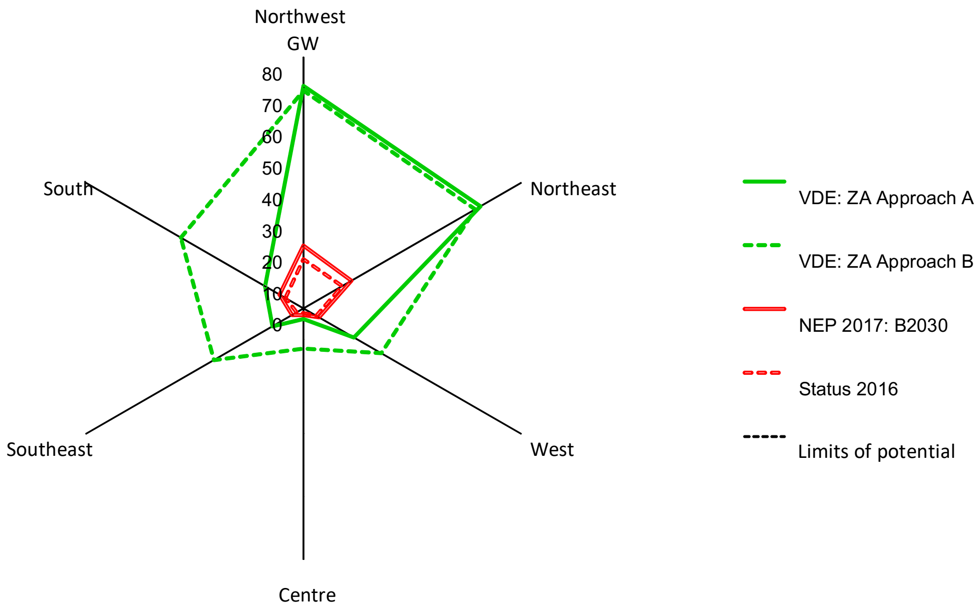
The scenario *FAU: Regional Components - MG_OPT1* also distributes the development of renewable energy expansion according to a different spatial pattern, which also results in a significant reduction in grid expansion requirement. This is mainly due to the robust expansion of wind power in the South zone. The capacity assumptions of the NEP are exceeded for the West zone by a factor of 2, for the Central zone by a factor of 4.9 and the South zone by a factor of 4.4.

The two scenarios - *50Hertz: EWO Competitive EW* (with slightly increased grid expansion requirements) and *50Hertz: EWO Prosumer-oriented EW* (with slightly reduced grid expansion requirements) - differ only marginally in terms of the expansion profiles for wind energy. In the scenario *50Hertz: EWO Competitive EW* the total capacity of all wind turbines is 1.4 times higher than the NEP level, for scenario *50 Hertz: EWO Prosumer-oriented EW* the total capacity of the wind turbines is approximately at the level of the NEP. In these two scenarios, however, wind capacity in the West zone is significantly higher than NEP assumptions (factor of 2 and 1.4, respectively).

None of the scenarios presented reaches the theoretical potential limits of wind energy in Germany. The more restrictive potential limits for 2030 (chapters 3.3 and 3.4) are exceeded for the scenarios *Prognos/FAU: Decentralization FB RE&EM* and *FAU:*

Regional Components - MG_OPT1 with a view to the South zone. For the scenario *Consentec: stress test - 100% carbon-free* and the North-West and North-East zones, such excess potential is rather dubious, taking into account the potential for offshore wind power generation.

Figure 4-3: Regionalization approaches Wind, Outlook

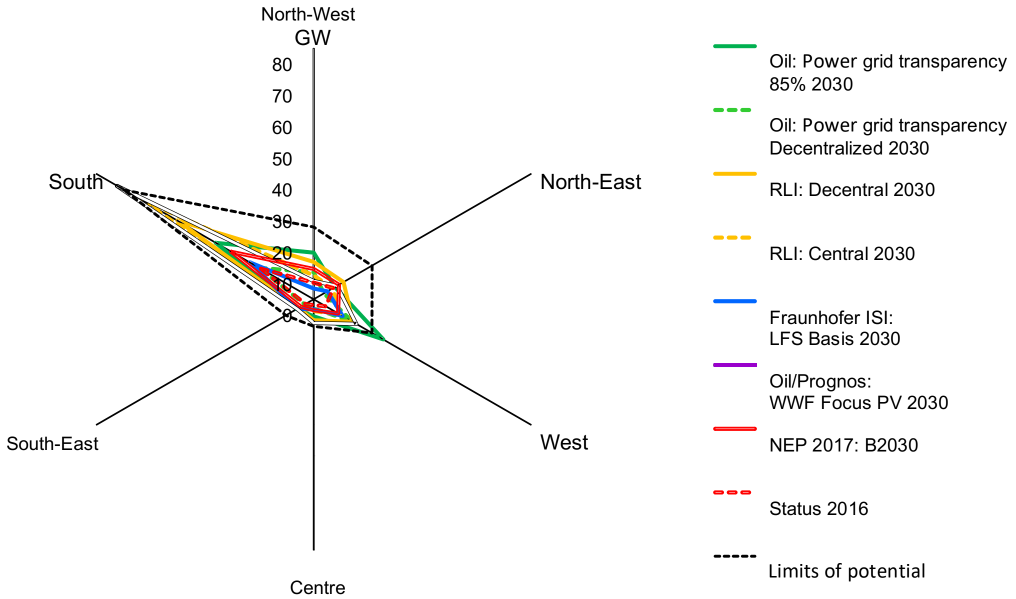


Source: Öko-Institut, based on aforementioned studies

Figure 4-3 gives an outlook on regionalization approaches for wind in a system whose power plant park consists of 100% renewables.

The scenarios *VDE: ZA approach A* and *VDE: ZA approach B* are characterized by very high wind power outputs. As scenarios for the long-term, they exceed the capacities assumed in scenario B 2035 of the NEP for 2030 by a factor of 2.3 and 3.1. They thus remain within the (theoretical) potential limits for wind turbines in Germany, but reach this limit in scenario *VDE: ZA approach B* (the scenario with significantly reduced transmission requirements) for the West zone. Although the expansion of absolute values is strongly concentrated in the North-West and North-East zones, significant production in the South and South-East zones can also be seen in *Approach B* scenario. Compared to the expansion structures of the NEP scenario B 2035, onshore wind capacities in the North-West and North-East zones increase by a factor of 2.0 and differ little between the two scenarios. There are, however, major differences for the West (3.1 in approach A and 4.8 in approach B), Central (1.5 and 5.6), South-East (2.5 and 7.2) and South (1.5 and 4.8). Whether such an expansion of onshore wind power is feasible, even for longer-term time horizons under broader consideration of restrictions, remains a matter for discussion.

Figure 4-4: Regionalization approaches Photovoltaics, 2030



Source: Öko-Institut, based on aforementioned studies

With regard to the total installed PV generation capacities, the various expansion scenarios differ to a much lesser extent. Compared to the NEP for 2030 and 2035, the approaches here differ by a factor of 0.8 to 2 and are also only slightly higher for the long-term perspectives (in the scenario *VDE: ZA approach B* by a factor of 2.3 compared to the NEP 2035).

Figure 4-4 shows various regionalization approaches for photovoltaics, initially for 2030. In contrast to onshore wind energy, the scenarios presented all show similar distribution whereby the strength of the characteristics differs according to the zone.

Several scenarios focus on very robust expansion in southern Germany, among them *Oil/Prognos: WWF Focus PV 2030* and *RLI: Central 2030*. Compared to the NEP scenario B 2030, PV expansion in the South zone is exceeded by a factor of 2.4 and 2.1 respectively.

A regionalization approach that differs from the other scenarios is pursued in the *85% oil transparency electricity grid* scenario, for which a particularly high expansion of photovoltaics is assumed in the west and partly in the north of Germany. This is 2.8 and 1.5 times higher than the NEP and is due to the high renewable electricity generation share of 85% (which can also be used as an approximation for longer-term time horizons). On the other hand, the expansion logic differs from that of the other studies: in order to meet the residual load in the North and West as effectively as possible within the region, a higher proportion of PV systems is added to the feed-in from wind onshore systems, so that generation profiles of these technologies can complement each other. Here, economic considerations do not play a part.

Particularly low PV expansion in individual regions can be observed especially for the two scenarios *Fraunhofer ISI: LFS Basis* and *Fraunhofer ISI: LFS geNA*. Here, the PV capacity levels achieved in 2020 in the North-West and North-East zones are 60 and 80% (North-West) and 50 and 40% (North-East) below those of the NEP.

The (theoretical) potential limits for the year 2030 become clear only in the scenario *Oil transparency electricity networks 85%* for the West zone and for the scenario O*il/Prognos: WWF Focus PV 2030,* slightly exceeded, for the South zone. The scenario *RLI: Central 2030* remains slightly below the potential limit used here for the South.

Figure 4-5 shows an overview of the various regionalization approaches for photovoltaics in 2035. The distribution of photovoltaic systems in 2035 bears a close resemblance to the scenario year 2030.

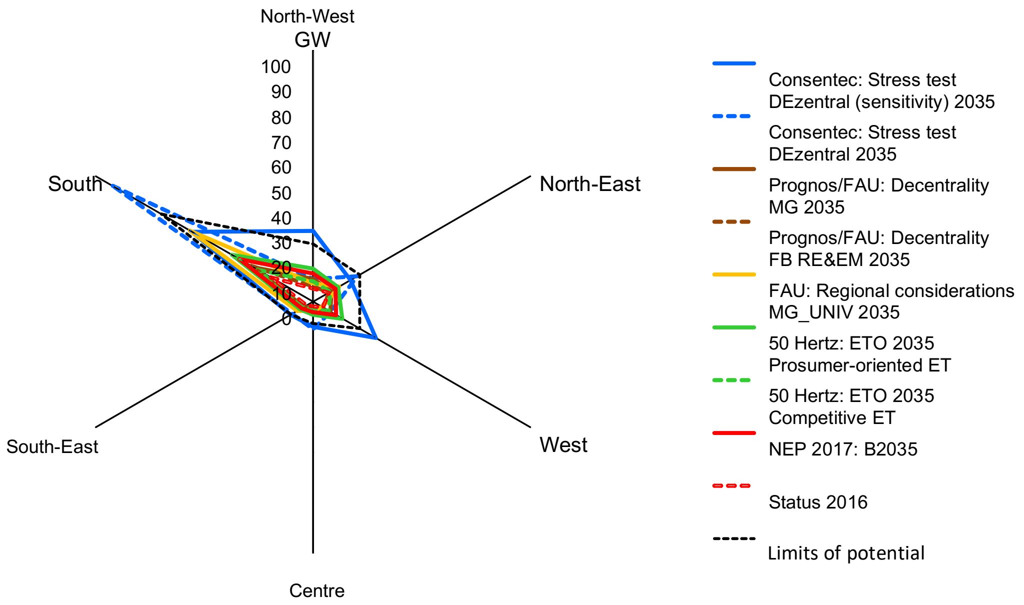
The *Consentec: Stresstest-Decentral* and *Consentec: Stresstest-Decentral (sensitivity)* scenarios are a clear exception. Both these scenarios assume particularly strong expansion in southern Germany (*Decentral*) or use a distribution algorithm based on the existing roof area potential (*Decentral sensitivity*). The approaches of the NEP scenario 2035 B are exceeded in the scenario *Consentec: Stresstest-Decentral* by a factor of 2.7 for the South zone and the Central zone and in the scenario *Consentec: Stresstest-Decentral (sensitivity)* by a factor of 2.7 for the West zone and by a factor of 2.4 in the Central zone.

Among the other scenarios shown here, only *FAU: regional components MG_UNIV* in the South and South-East zones shows clearly disproportionate shifts (factor 1.7 and 1.4 compared to the NEP).

At the same time, the expansion assumptions for some scenarios are significantly lower. In the *FAU: Regional Components MG_OPT1* and *Prognos/FAU: Decentralization FB EE&EM* scenarios, the expansion assumptions of the NEP for the West and Central zones are around 60% and for the North-West zone around 50% lower.

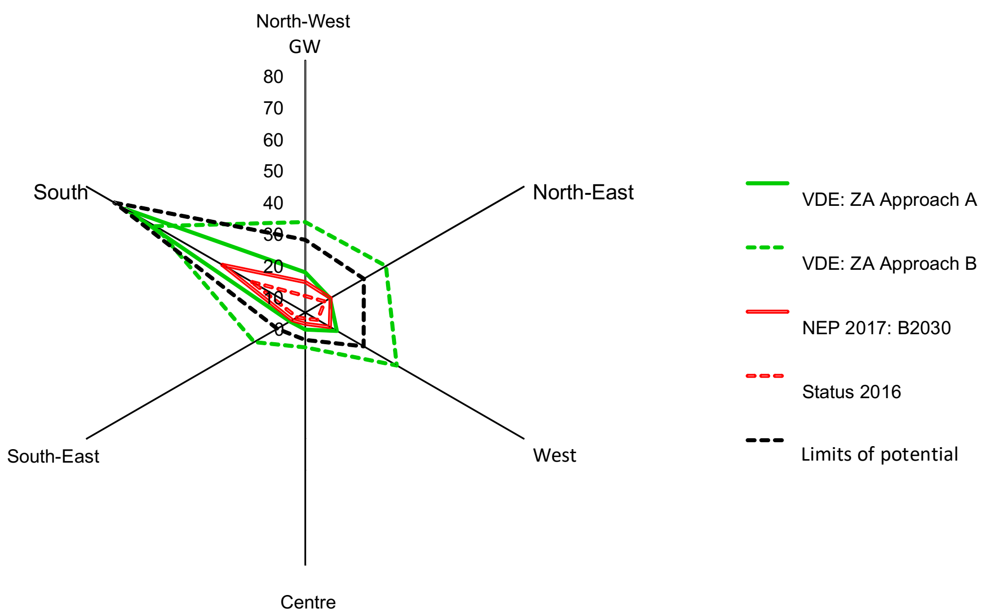
The potential limits set here for photovoltaics are only significantly exceeded in the scenarios *Consentec: Stresstest-Decentral* and *Consentec: Stresstest-Decentral (sensitivity)* for the West zone *Consentec: Stresstest-Decentral* and Central and South zones *Consentec: Stresstest-Decentral (sensitivity)*).

Figure 4-5: Regionalization approaches, Photovoltaics, 2035



Source: Öko-Institut, based on aforementioned studies

Figure 4-6: Regionalization approaches, Photovoltaics, Outlook



Source: Öko-Institut, based on aforementioned studies

Figure 4-6 shows regionalization approaches for photovoltaics in an electricity system whose power plant fleet consists entirely of renewables.

The regionalization approaches outlined in the *VDE: ZA approach A* and *VDE: ZA approach B* scenarios show comparatively high PV capacity in order to achieve a system with a full regenerative supply. Whereas the *VDE: ZA Approach A* scenario is based on the regional distribution of renewables in 2011, the *VDE: ZA Approach B* scenario assumes a distribution according to demand. Although in this scenario the potential limits of photovoltaics for 2030 are exceeded in almost every zone, in view of the longer time horizon, the expansion of PV generation capacities is by no means unrealistic.

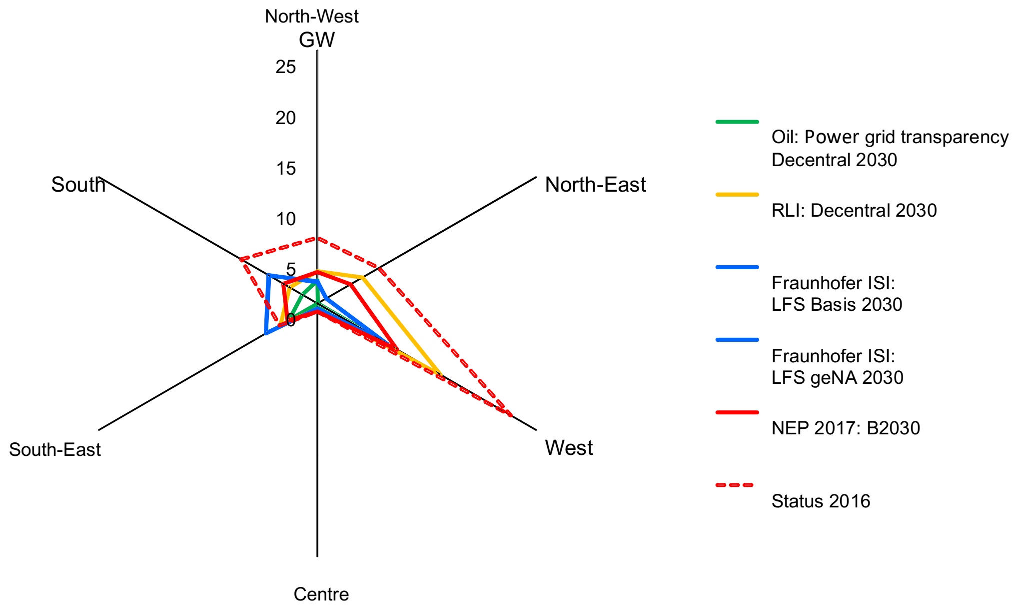
In addition to the assumptions (or results) for the expansion of wind and PV power generation, developments for conventional power plants in the various zones may also play a role in terms of grid expansion requirements.

Figure 4-7 shows different regionalization approaches in the field of coal-fired power plants for 2030. In contrast to developments in the area of renewables, the trends in the area of coal-fired power plants are almost entirely characterised by a significant decline in capacity.

The category "coal" includes lignite and anthracite energy sources.one As there are no theoretical potential limits in the zones for this technology category, none has been presented. Indeed, comparison with the actual state of 2016 is more meaningful here.

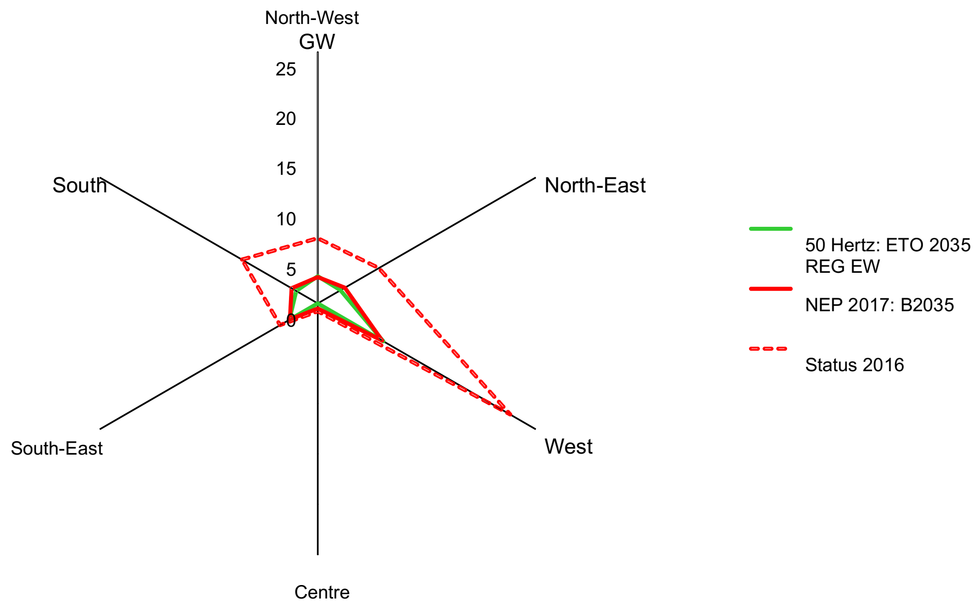
In all the scenarios considered, a reduction is shown of the total coal-fired power plant output compared to the current situation. With two exceptions, this also applies to developments in the individual zones. The exceptions refer to the scenarios *Fraunhofer ISI: Long-term scenarios: geNA 2030* and *Fraunhofer ISI: Long-term scenarios*. Based on 2030 with a view to developments in the South-East zone, however, this may be less attributed to a real increase in the number of coal-fired power plants than, at least in part, to the sections of the zones that differ slightly in the case of long-term scenarios. Since a smaller network expansion was assumed in this scenario, higher conventional capacities will be necessary to meet demand, especially in regions with high demand. In addition to the South-East zone, this can be observed above all for the South zone, for which coal-fired power plant capacities are declining significantly, but the values expected in NEP scenario B 2030 are exceeded by 80 and 70% respectively. However, as it is assumed that the emission targets set will be met, other regions, i.e. the North-East and West in particular, will have a significantly lower stock of coal-fired power plant capacities (80% and 40% respectively below NEP assumptions).

Figure 4-7: Regionalization approaches, Coal, 2030



Source: Öko-Institut, based on aforementioned studies

Figure 4-8: Regionalization approaches, Coal, 2035



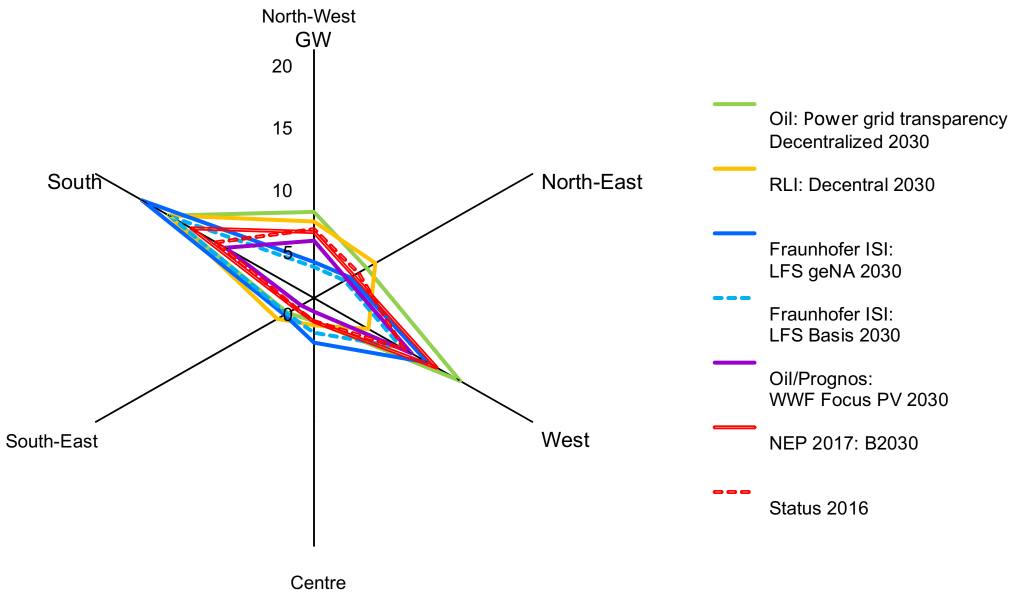
Source: Öko-Institut, based on aforementioned studies

In most other scenarios, the decommissioning of coal-fired power plants is very close to the developments assumed for the NEP scenario B 2030. The exceptions to this are the scenarios *Oil: Transparency of Electricity Networks Decentralized 2030* and *Oil/Prognos: WWF Focus Solar*. In these two analyses, the overall level of coal-fired power plants still in operation is 50% and 60% below the levels assumed in the NEP. In the North-East and Central zones, capacity is declining particularly sharply, i.e. almost completely. There are also further sharp declines for the West zone (50%), South-East (40% in the *Oil/Prognos: WWF Focus Solar* senario) and South (*Oil: Transparency of decentralized electricity grids 2030*).

In most studies which consider the year 2035 as the key scenario year and which assume the achievement of the energy transition targets, it is assumed that the installed capacity of the coal-fired power plants corresponds to that of the NEP scenario B 2035. A detailed presentation was therefore largely omitted in Figure 4-9. There are only minor deviations from the NEP, these for the scenarios *50Hertz: EWO EEG EW, 50 Hertz: EWO Competitive EW* and *50Hertz: EWO Prosumer-oriented EW.*

In scenarios that rely on very large shares of renewable power generation (*Oil: transparency of power grids 85% 2030, VDE: ZA approach A* and *VDE: ZA approach B*) or deal explicitly with coal phase-out (*Consentec: stress test - 100% coal-free*), coal-fired power plants automatically no longer remain in the system.

Figure 4-9: Regionalization approaches, Other, 2030



Source: Öko-Institut, based on aforementioned studies

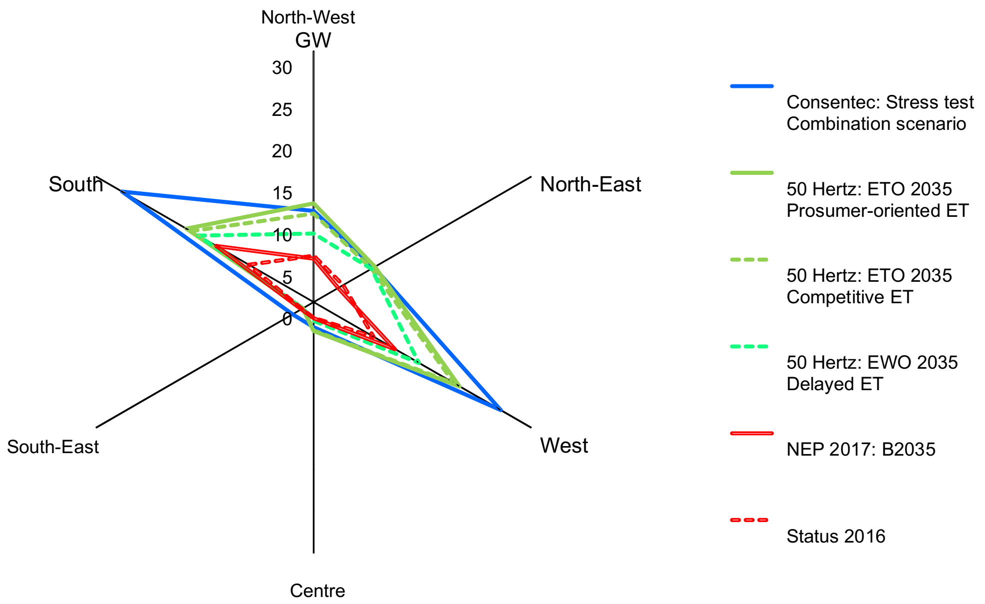
Figure 4-9 shows different regionalization approaches for the category "Other". Other energy sources include natural gas and biomass power plants. Since this category is a mixture of two technologies, a biomass potential limit has not been presented.

The installed capacity of this technology category shows a very similar regional distribution in the different scenarios. The focus is on the South and West zones. The level of benefit in these zones differs among the scenarios.

The scenario with the highest installed capacity in the South is the *Long-term scenarios: geNA 2030*, which assumes a reduced network expansion, hence targeted capacities must be added to meet the load. The *Oil: Transparency of Decentralized Electricity Grids 2030* scenario shows high expansion in the West zone as there is expansion of decentralized CHP power plants in order to meet the load there. Of all the scenarios, *RLI: Decentral 2030* shows the greatest performance in the North-East zone.

Compared to the assumptions of the NEP scenario B 2030, the installed capacity usually remains below the NEP values even in the scenarios mentioned. The values in the NEP scenario B 2030 are greatly exceeded only in the scenario *Oil: Transparency of decentralized electricity networks 2030* for the zones North-West, North-East and West (30%, 50% and 30% above the NEP levels), *RLI: Decentral 2030, RLI: Central 2030* and *RLI: Offshore 2030* for the North-East zone (70, 50 and 40% above NEP).

Figure 4-10: Regionalization approaches, Other, 2035



Source: Öko-Institut, based on aforementioned studies

Figure 4-10 shows the different regionalization approaches for the power plant category “Other” in 2035.

Also in 2035, installed capacity is particularly high in the South and West zones. The distribution of capacities is similar to the distribution in 2016, but some of the NEP's target values for 2035 are significantly exceeded. In the *Consentec: Stress Test - Combination Scenario*, the installed capacity of other power plants is 1.6 (Central zone) to 2.4 (North-

East zone) above NEP assumptions. For the South and West zones, which are particularly relevant here, the capacities assumed in the NEP are exceeded by a factor of 2.3 and 2.0 respectively. In the scenarios *50 Hertz: EWO EEG EW, 50 Hertz: EWO Competitive EW* and *50 Hertz: EWO Prosumer-oriented EW*, the installed capacity for all zones except the South-East is 1.2 to 1.3 (South zone) up to a factor of 2.3 to 2.5 (North-East zone) above the NEP values. For the Prognos/FAU decentralized scenarios there are significant deviations only for the North-East zone (40% above NEP). The same applies to Consentec's stress test scenarios, which have not yet been mentioned. FAU's analyses of regional components are based on the capacities planned in the NEP.

5. Synthesis and conclusions

In the preceding chapters, the connections, conflicts and considerations between decentralization and the future demand for electricity network infrastructures were examined in three different steps. Concepts of decentralization usually remain vague and (too) often at the level of rather imprecise narratives, so a holistic view of these three steps is prudent and, ultimately, indispensable.

In the first step, the purely qualitative classification, it is initially indisputable that photovoltaics, onshore wind power and offshore wind power technologies, which will be particularly relevant in the future, are largely characterised by lower capacity factors, greater spatial distribution, and a greater diversity of grid connection levels. Parts of this portfolio (large parts of PV and significant parts of onshore wind energy) can thus technically be classified as decentralized generation options.

Concerning the connection with network expansion, however, this perspective does not form a viable basis. A graduated approach is more useful here:

- The first aspect here is the proximity of generation plants to points of consumption. Power plants close to consumption centres can be small and decentral in technical terms, but they can also reach a considerable size. Even centralized systems can have different technical dimensions in terms of installed capacity, though smaller systems will frequently be located closer to consumption. A large proportion of decentralized installations can reduce grid requirements naturally, although this fully applies to the transmission grids, it could concern distribution grids to a much lesser degree.
- A second aspect arises from the proximity to consumption of flexibility options (demand flexibility, storage, backup power plants, etc.), which play a far more significant role in a regenerative power system than in current systems. Flexibility options are and will be necessary to balance the variable supply of wind and solar power generation and to balance the security of supply for periods of reduced supply of wind and solar energy. The flexibility options can also be decentralized or centralized. One extreme of storage-optimized self-consumption (i.e. decentralized generation and decentralized flexibility option) is offset by a second extreme of compensation for centralized power generation (such as offshore wind energy farms) with centralized flexibility options (such as via Scandinavian or Alpine hydropower). Between these two options, there lies on one hand the option of decentralized generation and centralized flexibility (hydrogen production in the

vicinity of large gas storage facilities, etc.) and centralized generation and decentralized flexibility (demand flexibility of large industrial plants, etc.) on the other. For now, only the combination of decentralized generation and decentralized flexibility can be assumed to require less grid expansion.

- The third aspect concerns the control model. The availability of decentralized flexibility does not automatically mean that this flexibility can be used in conjunction with nearby generation plants. Within the framework of liberalized markets, i.e. making free decisions on production and supplier selection, large-scale (central) markets or control signals (prices) will emerge, which will decide the use of flexibility options. Beyond the special case of optimizing self-consumption, this could only be avoided or limited if the extensive protection of regional markets were possible, e.g. on the basis of high infrastructure prices or the reintroduction of territorial monopolies. So if it is not possible to effectively and permanently delimit small-scale, cellular market areas, a central control model would require a strong network infrastructure, even in a system with decentralized generation and flexibility options. A lower power grid requirement can only be assumed with certainty if decentralized generation and flexibility options are combined in self-consumption solutions or (small) spatially tailored cellular control approaches come into play. It should also be noted that although cellular (market) systems or other regional markets are often mentioned at the concept or narrative level, no convincing or sufficiently developed implementation models have yet been identified.

Ultimately, in addition to the technical structures and spatial issues, the control model is particularly decisive. Concerning the different evaluation criteria, a number of reliable statements can be made at the qualitative level:

- Small-scale control approaches with a high proportion of decentralized generation based on renewables tend to lead to higher generation costs in the overall system if portfolio effects are eliminated and the need for higher electricity generation tends to arise, e.g. because overarching emission reduction targets are to be met. The decisive factors here are the corresponding volume effects; in view of falling levels and variation in production costs, the contribution from this aspect seems generally manageable. A situation similar to the cost issue arises beyond rooftop PV systems also with regard to the land and resource requirements for the combined generation options in the system if larger capacities are required for regenerative power generation due to a lack of interplay effects.

- The same applies to small-scale coordinated flexibility options. Without larger-scale portfolio effects, there will be higher costs for flexibility options, especially in view of the fact that a relatively wide range of different flexibility requirements must be covered. The cost increases can be limited if conventional flexibility options based on fossil fuels (e.g. decentralized gas power plants) are used, but these then lead to higher emission levels in the overall system. If these are to be avoided, the costs of (decentralized) flexibility options beyond the particularly inexpensive options (with limited availability) will increase sharply (if, for example, options that are not yet mature, such as electricity-based fuels on a larger scale, need to be activated).

From an economic perspective, the costs of the flexibility options must always be weighed up against the corresponding infrastructure costs. This matter cannot be answered with certainty at a purely quantitative level. However, the previously mentioned additional consumption of land and resources, including possible higher emission levels, will not be reliably compensated by the infrastructure.

In addition to economic and ecological criteria, aspects such as innovative strength ("decentralized innovation laboratories") and acceptance issues, e.g. with a view to opportunities for participation, are of great importance, particularly in the economic sense. In this respect, the question arises as to whether and to what extent the undeniable advantages of decentralized technologies necessarily require decentralized concepts for generation options and beyond that for flexibility options and, ultimately, small-scale control models. With regard to the latter two dimensions (flexibility options and control concepts), this does not necessarily appear to be the case, and/or other selective forms of improving participation and innovative strength could also be deployed.

Finally, in this regard, the question arises as to whether and when very broadly effective business models (beyond preference-based niche variants alone) or sharply defined decentralized control models could be brought into line with the existing regulatory framework for the European energy markets. The same applies to highly centralized models with strong and spatially high-resolution regional price components (such as nodal pricing), and a possible coexistence of both models. This area has not been considered in the studies presented here. However, the compatibility of broadly implemented decentralized control models with the current and foreseeable regulatory framework is a key requirement for determining whether, and for which time horizons such models can serve as a sound basis for infrastructure planning.

In a second step, these purely qualitative reflections, mostly based on literature evaluations, were supplemented by data analysis of the spatially high-resolution potential limits of solar and wind power generation, on the one hand, and the corresponding demand on the other. A potential analysis such as this, which initially completely disregards questions of cost or flexibility options availability, relying instead on spatially high-resolution quantity balances, enables initial quantitative classifications of the possibilities and limits of decentralized renewable generation options.

Small-scale, i.e. district level, analyses of electricity demand and differently defined potential assumptions for wind and solar power generation, show that

- there is a considerable concentration of demand in the industrial regions of western and southern Germany and in the metropolitan regions;
- high-yield solar power generation, especially in southern Germany and the roof potential in the metropolitan regions, can have an impact;
- high-yield wind power generation can be expected, especially in the North and North-East and in the offshore sector;
- challenges regarding public acceptance of onshore wind power plants, especially in densely populated regions, which are hence also characterised by strong demand for electricity, tend to have a restrictive effect on potential.

These restrictions decrease at the level of (selected) states but are still perceptible. At the next aggregation level of zones, the important role of electricity exchange remains discernible without prejudicing the criteria of costs, land use, emissions, etc., which are completely ignored at the potential level.

Consistently cellular concepts (analysed in the example at district level) could thus only be implemented with significantly greater use of network infrastructures with very broad use of flexibility options accompanied by the implications mentioned above. The quantitative analysis also shows that the larger the cells are defined, the more effective the interplay effects become. The need for flexibility options and the associated effects would decrease. Even with a very large input of cellular approaches it must be assumed that, in spite of the technological requirements and the costs involved, a significant amount of supraregional electricity exchange would take place.

In a third step, a wide range of differently oriented and methodologically very differently designed models of the German electricity system were subjected to comparative analysis. One of the key advantages of this study comparison in the context of the question underlying this study is that conclusions can be drawn about the consequences of various assumptions about, or modelling approaches to, the network requirement on a quantitative basis, or at least that orienting statements can be made concerning this. Individual studies also identify various cost elements. However, there are also limits to the comparability of the studies:

- The studies examine very different aspects impacting on network expansion. All of them are based on distribution patterns of power generation capacities calculated using exogenous or endogenous model data, the comparison of which is largely unproblematic. In addition, the studies take into account very different coordination approaches (price zones, *nodal pricing*, strong self-consumption segments, strictly regional control mechanisms, etc.). The effects of the individual mechanisms are sometimes difficult to differentiate.

- The metrics in the different studies, especially in the context of network expansion, differ greatly. Although robust comparisons can be made between individual scenarios in a modelling study and differences can be shown from the results of network development plans, further comparisons cannot be made easily.

- Where costs are reported, only in a few cases do they include the total system costs as the sum of generation, flexibility and infrastructure costs. Thus, and against the background of sometimes very different system boundary definitions, comparative analyses between the studies are only possible to a very limited extent.

The focus of the quantitative study comparison is therefore mainly on explicit and implicit regionalization approaches and their effects on network expansion requirements. Specifically regarding the scenarios that calculate a 20 to 50% lower network expansion requirement, the following points should be borne in mind:

- A very clear result of the comparisons is that all scenarios concluding with a significantly lower grid expansion requirement assume or result in a particularly strong expansion of onshore wind energy in the South zone. The magnitude of this additional expansion for 2030 and 2035 is 3 to 4 times, in extreme cases 6 times the values assumed in the current NEP (scenario B in each case).

- In the scenarios with lower grid expansion requirements, a disproportionate expansion of onshore wind energy in the West zone is usually assumed or calculated. Here, the additional expansion is 2 to 3 times, in two extreme cases 7 times higher than the assumptions of the NEP.
- One scenario with a significantly accelerated expansion of renewable power generation (85% by 2030) compared to other modelling produces an even greater expansion of onshore wind power generation (above a factor of 5 compared to the NEP), especially in the South and West zones. However, on the basis of these assumptions, the grid expansion according to NEP will then become necessary again.
- Only in this scenario is the theoretical potential limit reached in the West zone, all other projections remain below the respective theoretical potential limits. Subject to the "realistic" potential limits for 2030, these are clearly exceeded in the above scenarios with particularly strong wind power expansion in the South and West zones. The same applies to the analysis of the long-term decentralization variant of VDE.
- For the other zones, the differences are far less significant in terms of onshore wind power generation.
- The scenarios with a lower grid expansion requirement are mainly, but not consistently, characterized by very strong expansion of solar power generation in the South zone. The capacity level of the PV systems exceeds the grid development plan for 2030 and 2035 by a factor of 2 to 3.
- The potential limits for PV electricity generation in 2030 considered here are only reached or exceeded in the scenarios with particularly high expansion in the South zone. In the scenario with a renewable electricity share of 85%, the potential limits are also exceeded in the West zone. In VDE's long-term analysis, the potential limits for PV are exceeded in all zones except the South.
- In the scenarios for the development of coal-fired power generation, the variants for the lower grid expansion in the North-West, North-East and West zones show significantly lower coal capacities than in the NEP for 2030. However, the NEP for 2035 differs only marginally from the assumptions and results of the aforementioned studies with regard to the assumptions for the coal-fired power plant capacities on the market.
- In scenarios with little grid expansion, security of supply is guaranteed by higher capacity levels of other coal-fired dispatchable power generators (excluding coal-fired power plants). However, with a few exceptions, the range of power plant capacities allocated to the different zones spreads only moderately.

The available analyses do not give a clear picture of the extent to which decentralized control concepts (regardless of their feasibility or other implications) can lead to a lower need for network expansion. The individual details in this respect point to a 10 to 20% lower expansion requirement.

For 2030, the correlations between the extent of remaining coal-fired power plant capacities and the necessary grid expansion depend largely on the secondary conditions according to which the (additional) renewable electricity generation is regionalized. For

2035, the scope of coal-fired power generation no longer has any explanatory bearing on the dimensioning of grid expansion.

The decisive explanation for the different grid expansion requirements is thus clearly the regional distribution of renewable electricity generation with a distinctly dominant influence of the regional distribution of onshore wind power capacities.

With regard to the overall cost effects of different regionalization or control approaches, no reliable quantitative conclusions can be drawn from the available studies. The same applies to ecological factors such as land consumption or the influence on CO_2 emissions.

In addition to the findings mentioned above, a number of requirements and recommendations for action can be drawn from the summary. In order to intensify and objectify the debates on centrality, decentralization, regionalization and cellular control approaches in the context of network expansion needs, the following topics are of primary importance:

1. Are decentralized (cellular) control approaches beyond the optimization of self-consumption a reliable option for network expansion planning and/or for which time horizons are they relevant in this respect?
2. Which assumptions regarding expansion limits for onshore and offshore wind power and PV capacities can be regarded as robust for the various zones, especially with regard to the South and West zones, if factors such as land potentiality and acceptance are also taken into account?
3. How can uniform evaluation metrics be developed for the overall balance sheets with regard to costs and space requirements (in each case for generation plants, flexibility options and infrastructures)?
4. Which metrics can be developed to describe the extent of network expansion requirements in a comparable way and which also offers a possibility to serve as a pragmatic platform for the very different methodological approaches of model-based mapping of networks and supply reliability criteria?

The metastudy presented here is the first comprehensive attempt to analyse the complex, often narrative-influenced and demanding (both conceptually and data-related) material in the controversial field of decentralization and network expansion. There appears to be an urgent need for further research in this area.

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