Brandenburg
University of Technology
Cottbus - Senftenberg

Working Paper

2019/02

Why is Germany’s energy transition so expensive? Quantifying costs from wind energy decentralisation

Thorsten Engelhorn (BTU Cottbus-Senftenberg), thorsten.engelhorn@gmx.de

Felix Müsgens (BTU Cottbus-Senftenberg), muesgens@b-tu.de

Chair of Energy Economics
Brandenburg University of Technology Cottbus-Senftenberg
Prof. Dr. Felix Müsgens
http://www.b-tu.de/fg-energiewirtschaft/

TABLE OF CONTENTS

ABSTRACT

This paper discusses the efficiency of promotion schemes for renewable energy sources using the example of onshore wind energy in Germany. We analyse whether the scheme incentivised a cost-minimal capacity build-up. A model is developed to derive two cost-minimal benchmark scenarios which are compared to the historic capacity build-up for the period from 1995 to 2015. The costs of the two cost minimising benchmarks are significantly lower than the historic build-up (23 % to 30 % respectively). The cost reduction in the benchmarks is mostly resulting from building significantly fewer turbines, but at better wind sites. Hence, aggregated land use for turbines could also have been reduced significantly. Furthermore, we compare costs for consumers – as price discrimination of suppliers is sometimes used to justify additional payments to low-wind sites. However, our results show that the underlying policy objective is not reached: the efficiency gain in both benchmarks outweighs the distributional effect even from a consumer's perspective.

Index Terms: *wind power; energy policy; support scheme; market design; cost minimisation; efficiency*

1 INTRODUCTION

Investments in renewable energy sources (RES) are a global megatrend. For years, global capacity additions in RES have exceeded additions from conventional power sources. Due to this growth, the global share of "green" power plants already amounts to 34 % of total installed capacities (IEA, 2018). In many countries, the development has progressed even further. After two decades of steep growth, total installed RES-capacities in Germany, for instance, have exceeded conventional capacities since 2017 (Bundesnetzagentur and Bundeskartellamt, 2018). While becoming increasingly competitive, the bulk of this growth was and is still driven by support schemes. Given the significant amount of capacity additions in so many countries and associated costs, the right design of such support schemes is a top international policy issue.

An evaluation of a support scheme should begin by determining the policy objective. In the context of renewable energy sources, the reduction of carbon dioxide emissions is the most common objective but other objectives may also be pursued (cf. Bergek and Jacobsson, 2010). Once the policy objective is determined, measures to reach it can be implemented and evaluated. An evaluation should analyse effectiveness, efficiency and distributional effects. Effectiveness measures to what degree the policy objective is met. Efficiency measures the costs for achieving the objective (Haas et al., 2011; OSCE, 2009). Broadly speaking, the lower the costs for reaching an objective, the more efficient an instrument is. Distribution concerns whether money should be paid preferentially by (or be granted to) consumer (or company) A or B. Economic theory suggests that distribution and efficiency can be treated independently (i.e. maximize the size of the cake first and then organize distribution). Yet, in real world politics, it is often argued that efficiency has to be sacrificed to achieve a more desirable distribution. Hence, it should be discussed how to minimize welfare losses of politically motivated changes in distribution.

Efficiency in the context of renewable energy policy can be analysed according to the following three dimensions: technology, space and incentives.

“Technology”, as the first dimension, concerns the question of which technologies should contribute to a policy objective. In the context of global warming, most authors argue that instead of supporting RES-technologies specifically, priority should be on pricing carbon (e.g. Fischer and Newell, 2008; Boeters and Koornneef, 2011; Capros et al., 2011; Fell and Linn, 2013; Cramton et al., 2015). Some authors (e.g. Wang and Zhao, 2018) point out that even the net benefit of RES promotion on emission reduction is unclear under certain conditions. Marcantonini and Ellerman (2015) find that promoting RES was an expensive way of achieving decarbonisation. They attribute an implicit carbon price of 552 €/t for solar energy and 57 €/t for onshore wind in Germany (averages for 2006 to 2010), while European emission allowances were available for approximately 20 €/t. For the European energy sector, Müsgens (2018) compares a decarbonisation path based on the pricing of carbon with a path pursuing national RES-targets in combination with identical decarbonisation targets, and finds that pricing carbon saves up to 40 bn €/year. Other authors argue in favour of setting specific targets for CO_2-free technologies (e.g. Lehmann and Gawel, 2013).

If a RES promotion beyond pricing carbon is deemed necessary, the immediate follow up question – still within the “technology” dimension – is whether a technology-neutral RES support leads to an efficient technology deployment (e.g. Frontier Economics and r2b, 2013; Frontier Economics, 2014; Jägemann, 2014) or whether sub-targets for RES should be set to achieve this (e.g. Resch et al., 2009; Lehmann and Söderholm, 2018). In this context, additional aspects such as learning, industrial policy, R&D or environmental externalities beyond global warming, may justify additional instruments (cf. Kreuz and Müsgens, 2017, for an overview).

“Space” as the second dimension concerns the question of whether a support scheme’s reference area should be large or small in order to reach the policy objective. Most economists argue that it should be as large as possible. Simply put, larger regions generally enable investors to build at locations with the best access to natural resources (e.g. strong winds and solar radiation) and thus lowest expansion costs of RES. The latest EU-directive on RES-support fits this context as it encourages states to cooperate (Directive (EU) 2018/2001). Jägemann et al. (2013) find that there are substantial additional costs from national RES-targets compared with an aggregated EU-wide RES-target. However, some authors disagree with this view, inter alia because of transaction costs: it is easier to find and implement solutions on a national rather than international level. Further, international solutions may be unavailable and national solutions would be better than no solution at all. Another line of reasoning concerns the distributional effects of spatial allocations. De Jager et al. (2011) find that cooperation among EU member states reduces costs for consumers as compared to pursuing national targets with national resources alone. On the contrary, Klessmann et al. (2013), del Rio and Cerdá (2014) argue that large regions (in combination with technology-neutral support) increase producer rents at the cost of consumer rents. Their argument means that social welfare would have to be sacrificed in order to reach a consumer-friendly rent distribution. However, the net effect to consumers is unclear: consumers profit from redistribution, but also face a share of the welfare loss resulting from reduced efficiency.

We call “incentives” the third dimension measuring whether a support scheme promotes or impedes efficiency, even after the decisions on dimensions one and two are fixed. Within the example of support for onshore wind in Germany, incentives determine whether the most cost-efficient wind turbines (technology, dimension one) – of all possible turbines to be built – in Germany (space, dimension two) are built or not. Most likely, this would imply a certain concentration of wind turbines in northern Germany as the best wind sites are found close to the coast. To begin with, it is known from the literature (e.g. Pechan, 2017; Schmidt et al, 2013; Grothe and Müsgens, 2013) that the design of support schemes can (and does) influence the spatial distribution of wind turbines. This is also confirmed by Lauf et al. (2018) who investigate land-use policies to explain the spatial deployment of wind energy in Germany and Sweden. Goetzke and Rave (2016), Wurster and Hagemann (2018) and also Hitaj and Löschel (2019) consider political party preferences to account for heterogeneous growth patterns of wind energy in Germany; Xia and Song (2017), analyse agglomeration effects and the impacts of governmental support on Chinese regions to explain wind energy deployment in space and time. This last dimension is also where our paper contributes most: we analyse whether regulation of onshore wind incentivizes investment at the best wind sites and answer several related questions with regard to turbine locations, in-feed volatility, costs and consumer welfare.

To sum up, assessing the efficiency of a solution requires an analysis of i) technology options, ii) spatial resolution and iii) regulatory incentives guiding investment within the framework of i) and ii).). Figure 1 visualises this view.

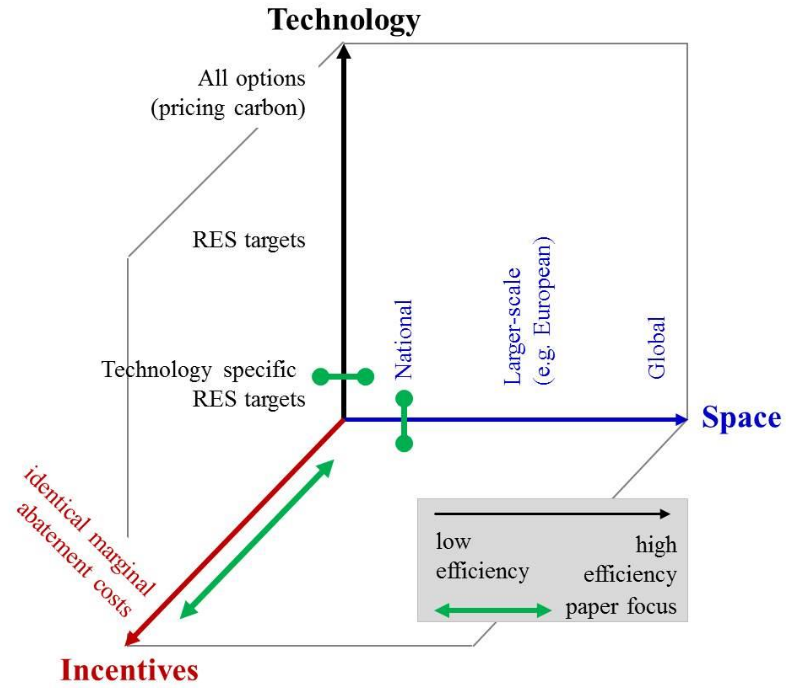


Figure 1: Dimension and policy options of (in) efficiency.

The green arrows in). Figure 1 explain the focus of our paper. Regarding “technology”, we assume the technology is fixed. We analyse the example of onshore wind. Hence, we do not pursue efficiency gains from allowing additional technologies to contribute to the policy objective (e.g. implementing a combined target for all RES-technologies). Further, regarding “space”, we assume national boundaries are binding. We restrict our analysis to one country and use Germany as an example. Hence, we do not explore efficiency gains from international cooperation. The single dimension we vary is “incentives”, i.e. we analyse why the design of historic onshore wind support did not achieve an efficient distribution of turbines and quantify how much more efficient the same objective (a fixed amount of annual wind energy) could have been met.[1]

The German case is ideal to study costs and efficiency of incentives in RES promotion: First, Germany did not focus its RES-support on the best available wind sites. Instead, support schemes specifically incentivized investment at low-wind sites, too. As a result, there are significant differences between the wind conditions of today’s wind farms (Jung et al., 2018). Second, the sample contains significant data. Germany is Europe’s largest onshore wind market by far (more than twice the installed capacity of Spain which ranks second) and the third largest market on the globe, exceeded only by China and the USA (World Wind Energy Association, 2019). Third, there is good data availability on turbines built. Fourth, “[d]espite its leading role

[1] Our approach is different to that in Hitaj and Löschel (2019), who estimate the impact of wind capacity additions in Germany since they a) vary the objective, b) set tariff levels exogenously and c) use an econometric model. It is also different to the approach in Drechsler et al. (2011, 2017) since they include externalities from RES to decide on power plant sites.

in global wind energy, Germany's wind energy industry remains understudied from an academic perspective" (Nordensvärd and Urban, 2015).

In terms of methodology, we firstly calculate the total costs of the historic onshore wind build-up in Germany. Secondly, we develop an optimisation model to determine a cost-minimal, counterfactual capacity development. We employ this model to derive two counterfactual benchmark scenarios with the same annual generation levels as the historic set-up. That way, we "normalize" effectiveness across scenarios and focus on efficiency and distribution (in particular consumer rents). Our analysis is based on highly granular wind speed data in time and geography, a comprehensive database on wind turbines and on GIS analysis to consider land potential. With regard to our use case, we answer the following **research questions**:

a. What are the additional costs of capacity additions at suboptimal onshore wind sites?
b. In a cost-minimal benchmark, where would turbines be located?
c. How much space would be used in a cost-minimal benchmark?
d. How would a cost-minimal fleet's hourly in-feed look like?
e. What would the distributional effects be?

Our research is relevant to market designers and researchers working on policy design for several reasons. Our results quantify the difference between an efficient solution and a real world policy design considering other factors (e.g. limiting producer rents). Our results compare solutions in terms of costs (answer to a.) as well as feasibility from a land planning perspective (answers to b. and c.). Examining hourly in-feed in d., we are e.g. able to discuss implications for expected additional grid costs from a less geographically diversified wind portfolio. Note that questions b. to d. have not yet been discussed in research on cost-optimal RES-expansion (cf. de Jager et al, 2011; Frontier economics and r2b, 2013; Jägemann et al., 2013; .Jägemann, 2014).[2] This is also true for our analysis of the wind sites chosen by our model and associated in-feed – usually subject of research into optimal wind portfolios.[3] Our findings in e. complete the picture as we check the common evaluation that efficiency-driven support schemes put consumers at a disadvantage (Klessmann et al, 2013).

Further, this article contributes beyond the analysis of onshore wind capacity additions in Germany. Results can be transferred and used in other contexts. Other regions and technologies could be analysed with the same methodology (e.g. efficiency gains from one European RES-quota instead of 27 national quotas or at least bi-national cooperation or harmonization between US-states).

[2] At least partly due to data resolution: Jägemann (2014) differentiates just two regions for wind onshore additions in Germany, Frontier economics and r2b (2013) differentiate 25 regions, for example.

[3] Roques et al. (2010) apply mean-variance portfolio theory to wind generation data of five European countries in order to identify portfolios, which minimise the variance of wind generation. Becker and Thrän (2018) minimise in-feed correlations of German wind sites to maximize wind farms' market value. Bucksteeg (2018) optimizes the allocation of turbines in Germany as to support generation adequacy, finding that a higher geographical diversification improves the reliability performance, yet increasing generation costs.

Even more broadly, our assessment shows the importance of quantifying the differences (in terms of costs, land use, hourly in-feed) between various market designs. Quantifying these differences enables market design decisions to be based on more transparent information and a more solid foundation.

The remainder is structured as follows. Section 2 defines our scenarios. Section 3 introduces our methodology and the data used. Section 4 presents our results. Conclusions and further research are discussed in Section 5. Additional results are published in an online supplement.

2 METHODS

This Section explains our methodological approach. We calculate costs for three scenarios with different wind capacity developments. Before we discuss these scenarios in detail, Table 1 gives an overview.

Table 1: Scenario overview.

	scenario 1: historic realisation	scenario 2: minimal costs	scenario 3: limited concentration
methodology	empirical observation	model	model
objective	-	cost minimization	cost minimization
constraints	-	basic constraints	additional constraints

2.1 Definition of scenario 1: historic realisation

Scenario 1 represents the historically observed development of wind energy capacity additions in Germany between 1995 and 2015.[4] In this period, installed capacity grew on average by 2.0 gigawatts (GW) or approximately 1,200 turbines per year, reaching more than 25,000 turbines by the end of 2015 (BMWi, 2018; Engelhorn and Müsgens, 2018; DeutscheWindGuard, 2016).

During the early years of our sample (1995–1999), the support for wind in-feed in €/MWh was equal to 90 % of the average price paid by end-consumers.[5] Given this unitary tariff level, especially good sites near the coastline were developed (Schmitt et al., 2006).[6] However, the average capacity growth was only approximatively 640 megawatts (MW) per year. To boost wind energy development (and also other RES), this tariff regime was replaced in 2000 by the *Renewable Energy Sources Act* (RESA).[7]

The overall objective of the RESA was to double RES's share in energy consumption within 10 years. In terms of the dimensions "technology" and "space", RESA was created as a technology-specific feed-in tariff uniformly valid within Germany. The sub-goal for wind was

[4] This spans 21 years, which is the maximum period covered by law.
[5] According to the Law on Feeding Electricity into the Grid (StrEG). The average was determined in the preceding two years.
[6] End-consumer prices did not vary much.
[7] Turbines erected before could opt into the new conditions.

a significant contribution to the overall objective of the RESA and, at the same time, (given a feed-in tariff) a prevention of rent shifting from consumers to producers.[8]

In the following four years, the annual average capacity growth of wind energy more than tripled. RESA is recognized as the key driver of wind energy expansion in Germany (Nordensvärd and Urban, 2015). Since then, turbines were distributed more spaciously and more low-wind sites, especially in the inland, were developed alongside high quality sites over time (cf. Figure 2: Historic capacity build-up and site qualities.; Hitaj and Löschel, 2019).

[8] The recommended resolution and report of the Committee for Economy and Technology (Deutscher Bundestag, 2000) states that the new regime prevents excess support at coastal sites and incentivises development at sites in the inland.

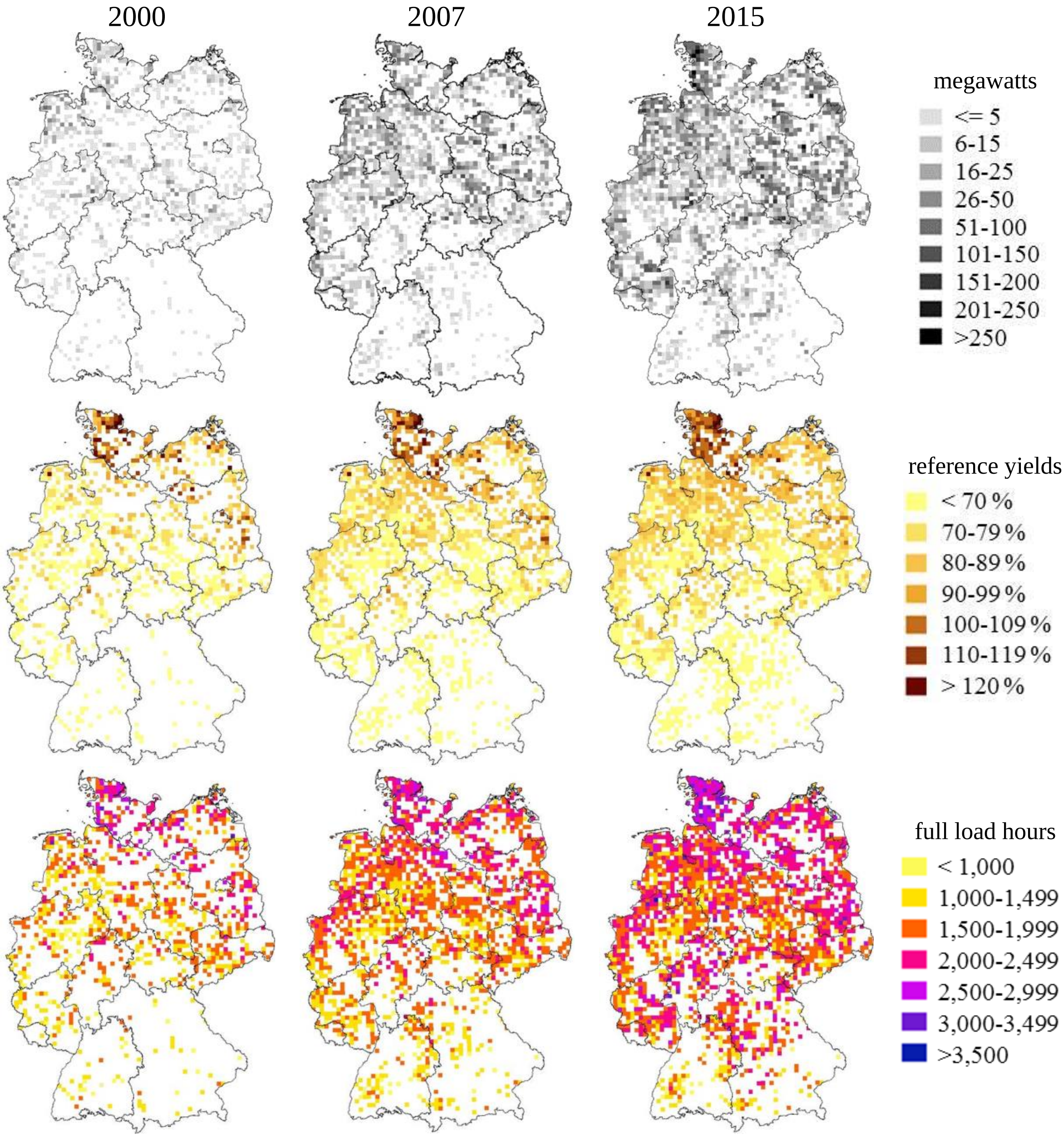


Figure 2: Historic capacity build-up and site qualities.

Incentives – provided for in the RESA – were the driving force behind building turbines on sites with little wind: specific support (in €/MWh) at low wind sites was higher than at high wind sites. In other words: Turbines with higher production costs received higher levels of support than turbines with lower costs such that, ultimately, investors were financially compensated for poor site quality. Tariff levels were amended in 2004, 2008, 2011 and 2014, but this central mechanism, the so-called reference yield model, did not change: More details of this model are discussed in appendix A.

The incentive system encouraged the development of projects on a diverse range of sites, which was politically justified for reasons of increasing different regions' participation and public acceptance. Lower grid extension costs are also mentioned, but a solid analysis on the subject is lacking.

2.2 Definition of counterfactual benchmark scenarios

The two counterfactual benchmark scenarios (*short*: benchmarks) simulate an alternative onshore wind capacity build-up between 1995 and 2015. Both minimize total production costs in the objective function. The difference between the scenarios is in constraints. Scenario 3, the second benchmark, is more constrained than scenario 2, the first benchmark.

The cost minimization algorithm will prioritize available, low-cost sites. A site, or location, is defined as an area of wind energy use in a rectangle on the landmass, called **raster** (indexed r), of 10 x 10 km (of which there are about 3,700 in our case). All turbines in a raster are assumed to face equal (though height-dependent) wind speeds and regulations (e.g. restricting hub heights).

In terms of constraints, we start by ensuring that aggregated annual onshore wind generation[9] in the two benchmarks matches historical values. Thus, we exclude the effectiveness of promotion schemes and, in line with our research question, focus on costs advantages and efficiency.

Further, turbines can only be added if:

a. they are commercially available in the year of installation;
b. they are certified (wind class) and allowed (total height) at the relevant raster; and
c. there is still enough land potential for wind energy use at the relevant raster.

Scenario 2, which is our first benchmark, does not impose any further constraints. Hence, it is possible that capacity is regionally concentrated.

Scenario 3 is our second benchmark. The difference to scenario 2 lies in three additional restrictions we impose on capacity additions per raster and year. The first additional restriction limits the annually allowed number of turbines added in a raster, the second the total allowed number of turbines added in a raster. The third restriction limits the total land use of all turbines in a state to a state's regulatory future goal of wind energy land use. All restrictions provide that capacity is added less densely distributed. This is explained further in Section 3.1.2.

3 METHODOLOGY AND DATA SET

Section 3 is split in three subsections. In 3.1 we briefly explain how historic turbine data is gathered in scenario 1 but mainly establish an optimisation model to determine which turbines are built in the two counterfactual benchmark scenarios. In 3.2 we calculate the total costs of capacity build-ups in all scenarios, i.e. the historic built up in scenario 1 and the two benchmarks in scenario 2 and scenario 3. Based on these results, we quantify the additional costs of scenario 1 as compared to our benchmarks. In 3.2.4 we estimate the additional costs for consumers only, also in comparison to our benchmarks. Here, we test whether consumers would indeed pay more or whether the efficiency gain exceeds the change in rent shifting.

[9] Throughout this paper, we use "yield" and "generation" interchangeably.

3.1 Determination of built turbines

To answer our questions, we need information on the costs in all scenarios which, in turn, requires information on turbines built – the key difference between the three scenarios. For scenario 1, the challenge is to gather the cost parameters for all built turbines in Germany in our period. As we can resort to a recent research (Engelhorn and Müsgens, 2018) in this regard, we describe the process briefly in 3.1.1. For our benchmarks, we develop an optimisation model, which is presented in Sections 3.1.2 to 3.1.3.

3.1.1 Turbines in historic realisation: origin

Each built turbine (indexed bt) has certain properties. In scenario 1, these properties are identified based on historic capacity additions. We obtain our data from the publicly available online supplement of Engelhorn and Müsgens (2018). It contains comprehensive data on around 25,000 turbines built in Germany before 2016. For all built turbines, we use this dataset to determine:

- start-up year;
- model and power curve, PC_{bt} (a function mapping wind speed to electricity generation);
- hub height, z_{bt};
- location (geo-tagged);
- rotor diameter, rd_{bt} (used to deduce a turbine's land use); and
- investment cost, IC_{bt}.

Based on these data which, as an aggregate vector, we refer to as **specifications** of a turbine, $\mathrm{SPECS_{bt}}$, we answer our questions for the historic empirical set-up (i.e. scenario 1).

3.1.2 Turbines in benchmarks: common equations for optimisation

In our cost-minimized benchmarks, we need to simulate a counterfactual capacity build-up. The goal is to derive scenarios with minimized generation costs but catching key elements (e.g. technical feasibility, identical annual wind generation) of historic feed-in. We formalize this approach in the following linear optimisation problems, consisting of an objective function and several constraints.[10] The objective function for each scenario sequentially determines 21 annual turbine specific investment decisions for years 1995 to 2015. Note that this algorithm does not guarantee a global cost minimum as the problem is not solved simultaneously. Therefore, with regard to cost differences between our scenarios, our approach is cautious as it increases costs in our benchmarks and thus reduces cost differences to scenario 1. Though our approach could be rephrased algebraically to guarantee a global minimum, this is prevented from being solved empirically by the complexity and size of the problem (15,000 turbines, selected out of around 570 potential configurations in about 3,700 raster cells).

The objective of each decision is to minimize **gross generation costs** of turbines built in that year, $\boldsymbol{GGC_y}$, as stated in Eq. ((1):

[10] The problem is implemented in GAMS and solved with cplex.

$$minimize\ GGC_y = \sum_{bt=n_{y-1}}^{n_y} IC_{bt} + \sum_{i=0}^{19} \frac{OC_{bt,y+i} \cdot \overline{yield}_{bt}}{(1+WACC)^i}, \quad with\ n_{1995-1} = 0. \tag{1}$$

In the objective function, IC_{bt} specifies a turbine's nominal investment cost [in €] and $OC_{bt,y+i}$ the annual nominal variable cost of operation [in €/MWh].[11] The latter are multiplied with $\overline{yield}_{bt}$ [in MWh/a] which is the average annual yield a turbine would have generated over a 20-year-period. We use this average to take into account that investment decisions in practices have to be based on expected generation, instead of (at the time of investment, unknown) future generation.[12] $WACC$ specifies the annual weighted average cost of capital, which we set to 5.3 %.

The objective value in Eq. ((1) is minimized by determining which and how many new turbines are built in a year. This is tracked with index $bt \in \mathbb{N}$ which gives a unique identifier to every turbine built by the optimisation problem, starting in the first period of observation. In this context, we define n_y as the (endogenously determined) aggregated number of turbines built before the end of year y. For example, all turbines built before the end of 1995 have values of bt between 1 and n_{1995}. In the following year ($y = 1996$), $n_{1996} - n_{1995}$ new turbines are built with indices $n_{1995} < bt \leq n_{1996}$. Thus GGC_{1996} in Eq. (1) comprise investment costs (IC) as well as operating costs (OC) for these turbines only. Turbines built before (i.e. in 1995) still exist, but cannot be influenced by the optimisation decision in that year (i.e. 1996) and therefore are neglected in that year's optimization. This way, we focus on what can still be influenced, i.e. new investments.

Eq. ((1) essentially minimises the levelised costs of electricity production (LCOE) for the desired amount of wind energy. While this is the most common approach in the literature, several authors (e.g. Joskow, 2011; Grothe and Müsgens, 2013; Engelhorn and Müsgens, 2018) point out that it neglects wind turbines' market values, i.e. differences in the value of electricity produced. In this study, we assume identical market values for all turbines and all three scenarios.[13] The main reason is that a detailed analysis of market values would require an integrated wholesale electricity market simulation with assumptions on commodity prices, investment costs as well as investment and dispatch decisions for both RES and conventional power sources up until 2035, which we do not consider in the focus of this paper.

In addition to the objective function, we implemented several constraints to generate meaningful results. The **first constraint** is formulated in Eq. ((2)). It restricts turbines built in the benchmarks to so-called "candidate turbines", i.e. to commercially available and locally authorized models:

[11] Assumed operational costs: online supplement, Table 2.

[12] Alternatively perfect foresight could be assumed, which is not uncommon in energy market modeling (e.g. Müsgens, 2006; Gils et al., 2017) but would overestimate potential cost savings as historic investments in scenario 1 had to be based on expectations.

[13] However, to get a better understanding of the robustness of these assumptions, we analyse the fleet's hourly in-feed in all three scenarios (research question d.); as we will see later, the correlations between scenarios are very high.

$$specs_{bt} \in specs_{ct} \; \forall \; bt. \tag{2}$$

The specifications for candidate turbines (indexed ct) are taken from the online supplement of Engelhorn and Müsgens (2018). It contains specifications of 188 turbine models at several hub heights and data on market availability. Our data source covers legal requirements in that it provides information as to total height restrictions as well as wind class certification. Based on these data, Eq. (2) guarantees that all built turbines are commercially available at the time of installation and comply with local height and certification requirements. Note that our approach of "modelled selection" from a turbine pool differs from other studies, which work with predefined turbines at certain sites or regions (Wimmer et al., 2014; Konetschny et al., 2017; Bucksteeg, 2018).

The **second constraint** is formulated in Eq. ((3)). It guarantees that the aggregated annual generation of all turbines is at least as high as the historically observed annual yield, h_yield_y, which is also the annual generation in scenario 1.[14] Note that all turbines built in or before the year in question are included.

$$\sum_{bt=1}^{n_y} yield_{bt,y} \geq h\_yield_y. \tag{3}$$

According to Eq. ((4)), we calculate a turbine's annual yield, $yield_{bt,y}$, as its gross yield, $g\_yield_{bt,y}$, multiplied by a loss factor, $loss_{bt}$, and a correction factor, $corr_{bt,y}$:

$$yield_{bt,y} = g\_yield_{bt,y} \cdot loss_{bt} \cdot corr_{bt,y}. \tag{4}$$

Gross yield is calculated with Weibull distributed wind speed data and turbines' power curves. The methodology is described in detail in Engelhorn and Müsgens (2018): [15]

$$g\_yield_{bt,y} = 8760 \cdot \int_0^{\infty} wpdf_{bt,y}(v) \cdot PC_{bt}(v)\, dv. \tag{5}$$

The correction factor considers overestimation with reanalysis wind data.[16] The loss factor considers downtime, wind shadow (downwind: less energy), power and other losses:[17]

$$loss_{bt,y} = (1 - downtime_{bt}) \cdot (1 - windshadow) \cdot (1 - other). \tag{6}$$

The **third constraint** is formulated in Eq. ((7). It restricts the amount of turbines per raster based on available space for wind energy use. Aggregated turbines' land use in a raster cannot exceed this potential:

$$\sum_{bt=1}^{n_y} land\_use_{r,bt|bt\ in\ r} \leq potential_r \; \forall r, \tag{7}$$

We calculate a turbine's land use (in hectares) with an empirical formula based on rotor diameter. This takes turbine configurations into account and is more precise than a general

[14] Maximal historical annual wind generation is 70.9 terawatt-hours (2015).

[15] For annual yield calculation in scenario 1, wind speed data of the geo-tagged turbines' locations is used; for turbines in our benchmarks, data at a raster's centre is used. This is also true to hourly yield calculation in Section **Fehler! Verweisquelle konnte nicht gefunden werden.**.

[16] See also Staffell and Pfenninger (2016). As loss factor, we use values derived in Engelhorn ans Müsgens (2018).

[17] Downtime: 3 %, wind shadow: 8 %, electric losses: 1.5 %, other losses: 2.5 %. This leads to a total loss of 15 %.

factor converting potential to capacity used (e.g. 8 MW/hectares) (Umweltbundesamt, 2013). To avoid a so-called park effect[18] in simulating concentrated capacity build-ups[19], we apply a commonly used distance between turbines[20]:

$$land\_use_{bt} = \pi \cdot \mathrm{rd}^2 \cdot 5/10{,}000. \tag{8}$$

We determine a raster's free potential (right hand side in Eq. ((7) in 1995 in three steps (the approach is described in detail in McKenna et al., 2014).[21] First, unsuitable areas for wind energy use (environmentally protected areas, water bodies, areas with gradients steeper than 20 degrees as well as settlements and infrastructure such as streets, railways, airports and high-voltage lines) are deducted from the German land mass with a Geographical Information System software.[22] Second, unsuitable areas are surrounded by buffers of varying distances which are then deducted from the remaining potential.[23] Third, the remaining potential is linked to land use categories from the European CORINE project and multiplied with suitability factors for wind energy use.[24] These factors are based on small-scale analyses and account for further factors hindering wind energy use, which cannot be addressed by explicit buffering. These three steps are the only constraints on space considered in scenario 2. This scenario is thus comparably unrestricted.

3.1.3 Additional constraints for scenario 3

In scenario 3, we significantly limit available sites further to address additional factors limiting the concentration of wind turbines at good sites, such as regulatory authorisation of wind turbines (cf. Goetzke and Rave, 2016). Admissibility is regulated by the interaction of spatial planning law, zoning law and regional planning provisions, where the latter are substantiated by municipal or county-level bodies, leading to approximately 2,000 development areas regulating wind energy (Einig et al, 2011). Furthermore, other factors, such as turbine-specifically required eco-audits or technical limitations, may prevent building turbines in strong wind sites.

Scenario 3 includes three further constraints (number four, five and six).

The **fourth constraint** is motivated by technical limitations as, for example, construction sites in a limited space. It limits the annual number of newly built turbines in a raster to 20 % of new turbines built in that year. To implement this constraint, we define $n_{r,y}$ as the aggregated number of turbines built in raster r before the end of year y (in analogy to the already defined n_y). This constraint limits the concentration of new capacity in few places in a year:

[18] It describes additional losses of energy due to the narrow spacing of turbines. These are additional in the sense that they encompass the losses due to wind shadow already integrated in our calculation.
[19] The smaller the land use, the higher the turbine concentration at good sites and thus the lower the cost associated with it.
[20] See appendix B for a comparison of studies.
[21] Each raster's geo-code and potential: online supplement, Table 3.
[22] See appendix B for a summary of the spatial datasets used.
[23] For a comparison of our buffering against four other studies: online supplement, Table 4.
[24] This way the potential of steps 1 and 2 is reduced by 10 to 80 %.

$$n_{r,y} - n_{r,y-1} \leq 0.2\left(n_y - n_{y-1}\right). \quad (9)$$

The **fifth constraint** is motivated by local acceptance which may reduce the number of turbines approved in a raster. Acceptance is important as wind turbines cause externalities to residents, which in turn might decelerate its expansion (Meyerhoff et al, 2010; Sunak and Madlener, 2016). The constraint limits the total number of turbines in a raster (over the observation period) to twice the aggregated number historically built in that raster:

$$n_{r,2015} \leq 2 \cdot h\_n_{r,2015}. \quad (10)$$

Hence, $h\_n_{r,2015}$ is set equal to the number of turbines historically built in r by the end of 2015. We thus assume a positive correlation between acceptance for additional turbines and the number of turbines already built.[25] Consequently, the model does not build turbines in a raster without historic capacity additions, even if there are potential and strong winds.

The **sixth constraint** limits the total land use of all turbines in a state to the designated land use target for wind energy of a state. The targets, in hectares per state, are taken from the latest network extension plan (Bundesnetzagentur, 2018) and represent regulatory and political ceilings up until 2050, respectively.[26] We include this constraint, valid between 1995 and 2015, to prevent land use in certain states from exceeding a level, which was accepted for the future in 2018. The levels do not exceed 2 % of the state area – a popular criterion for the maximum designation of wind energy use at the German state level (Konetschny et al., 2017).

$$\sum_{bt=1}^{n_y} land\_use_{state,bt|bt\ in\ state} \leq target_{state}\ \forall state,. \quad (11)$$

Figure 3 visualises our optimisation process for scenario 3.

[25] Goetzke and Rave (2016) find that wind power expansion on the German county level and Green Party votes are positively correlated.
[26] Maximum land use target per state: online supplement, Table 10.

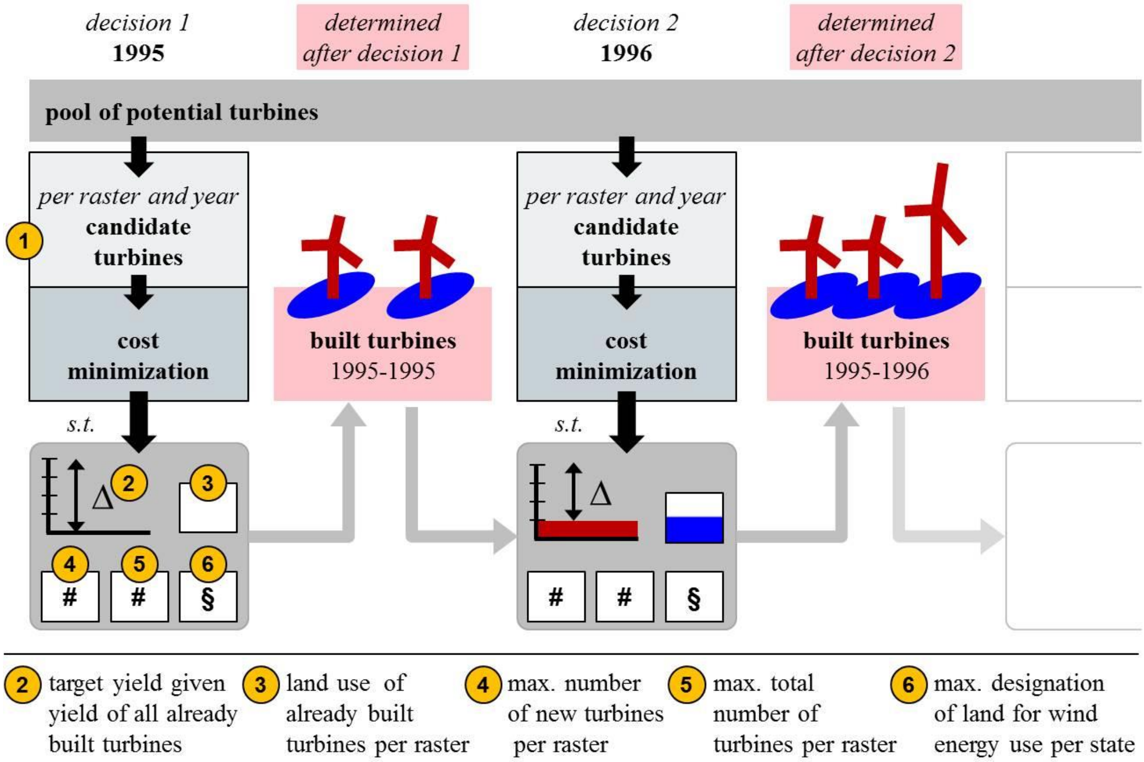


Figure 3: Benchmarks: cost minimisation and capacity build-up under restrictions.

3.2 Quantifying differences between scenarios

At this point, we have determined three different capacity build-ups covering the period 01/01/1995 to 12/31/2015. For all build-ups, we determined where and which turbines (would) have been built, how much each turbine (would) have cost and how much it (would have) produced. To answer our research questions, we use this turbine specific information, but the results require further processing.

3.2.1 Additional constraints for scenario 3

To calculate **total costs**, $\boldsymbol{TC}$, for each scenario, we aggregate annual investment and operating costs from 1995 to 2015 of all turbines added, according to Eq. ((12):

$$TC = \sum_{y=1995}^{2015} \sum_{bt=1}^{n_y} \left(\left(AIC_{bt} + OC_{bt,y} \cdot yield_{bt,y} \right) \cdot CF_y \right). \tag{12}$$

Note that there are differences between Eq. ((12) and Eq. (1) (used to determine which turbines are built in the benchmarks). To calculate and compare total costs between scenarios, we focus on annualized investment costs, AIC. That way, we minimize differences in residual values between scenarios. With annualized investment costs, by the end of 2015, turbines have covered a share of investment costs proportional to the share of amortization passed up to that year. Second, we calculate yield based on actual wind conditions in a year because we compare realised rather than expected operational costs. Third, nominal values are converted to real values from 2018 with an annual compound factor, CF_y, based on German consumer price increases (Deutsche Bundesbank, 2019).

A turbine's annualized investment costs, AIC_{bt}, is calculated based on IC_{bt} and $WACC$:

$$AIC_{bt} = IC_{bt} \cdot \left(\frac{(1+WACC)^{20} \cdot WACC}{(1+WACC)^{20}-1}\right). \tag{13}$$

We do not consider additional (balancing, reliability, congestion and grid-related) costs associated with variable RES (cf. Ueckerdt et al., 2013; Heptonstall et al., 2017), but discuss this in the light of our results. After calculating total costs for all scenarios, we compare the costs and quantify the efficiency loss of capacity additions at suboptimal sites. The results to research question a. are shown in Section 4.

3.2.2 Calculation of turbine locations and land use

Based on the choice of turbines in the benchmarks, we can quantify where, how many and what type of turbines are installed in any raster. Land use per turbine and aggregated land use per raster are calculated as in Eq. ((7). All other information to answer research questions b. and c. is contained in $specs_{bt}$. The results are presented in Section 4.

3.2.3 Calculation of hourly yield

This far, we focused on annual yields to determine capacity allocations. However, we also want to shed light on the differences in disaggregated, hourly yields between scenarios (research question d.). To calculate hourly yields, we use the following data from Engelhorn and Müsgens (2018):

- hourly (reanalysis) wind speeds at 80 metres hub height, $v^{80}_{bt,y,h}$,
- shear factors, $s_{bt,y,h}$ (to transform wind speeds to the hub height),
- wind speed correction factors (for calculation with hourly data), $correction_{bt,y}$.

Given this data we derive hourly corrected wind speeds according to Eq. ((14)):

$$v_{bt,y,h} = v^{80}_{bt,y,h}(z/80)^{s_{bt,y,h}} \cdot correction_{bt,y}. \tag{14}$$

Then, a turbine's hourly yield follows from its power curve (Eq. (15)). Summation of all turbines' yield operating in the same year gives the fleet's hourly yield (Eq. (16)):

$$yield_{bt,y,h} = PC_{bt}(v_{bt,y,h}), \tag{15}$$

$$fleet\_yield_{bt,y} = \sum_{h=1}^{8760} yield_{bt,y,h}. \tag{16}$$

The results to research question d. are shown in Section 4.

3.2.4 Calculation of consumer payments

The German wind support scheme was sometimes justified with rent shifting from producers to consumers (Deutscher Bundestag, 2000; Gawel et al., 2017). Essentially, this argument means sacrificing producer welfare to increase consumer welfare (and thus acceptance). In comparison with an efficient solution, this policy obviously reduces social welfare: producers lose more than consumers gain. However, a careful empirical analysis is needed to determine whether the goal of reduced consumer costs is indeed achieved. Two opposing effects have to be quantified. On the one hand, both consumers and producers are negatively affected by the inefficiencies resulting from suboptimal capacity additions, i.e. building turbines at low instead of high quality sites. On the other hand, consumers profit from price discrimination (at the expense of producers). Assuming perfect competition, both effects can be quantified with our model. We quantify **gross consumer costs**, $\boldsymbol{GCC}$, in real values as expressed in Eq. ((17) to answer this question (research question e.):

$$GCC = \sum_{y=1995}^{2015} \sum_{bt=1}^{n_y} \sum_{m=1}^{12} payment_{bt,y,m} \cdot yield_{bt,y,m} \cdot CF_y. \tag{17}$$

GCC are based on consumers' payments to the investor of a turbine [in €/MWh], $payment_{bt,y,m}$.

In scenario 1,GCC is set equal to total costs. This means, we assume that the tariff level was perfectly set by the regulator and hence consumers did not "overpay" producers (cf. 3.2.1). If gross consumer costs were higher than total costs, the costs savings of our benchmarks would even be larger.

In our benchmarks, we determine $payment_{bt,y,m}$ for all turbines built in a particular year based on the simulated market clearing price of a perfectly designed auction, i.e. the production costs (measured as levelized cost of electricity generation, LCOE) of the most expensive turbine built in that year:

$$payment_{bt,y,m} = \max_{bt\_y} LCOE_{bt\_y}, \tag{18}$$

with bt_y referring to the subset of all turbines built in the same year as the turbine with index bt. A turbine's LCOE is calculated according to Eq. ((19)):

$$LCOE_{bt} = \frac{IC_{bt,iy} + \sum_{n=0}^{19} OC_{bt,iy+n} \cdot yield_{bt,1995+n} / \left(1+WACC\right)^n}{\sum_{n=0}^{19} yield_{bt,1995+n} / \left(1+WACC\right)^n}. \tag{19}$$

4 RESULTS

This section presents our results. A summary is given in Table 2.

Table 2: Summary of results on research questions a, c, d and e.

	scenario 1: historic realisation	scenario 2: minimal costs	scenario 3: limited concentration
research question a.			
total costs [bn €$_{2018}$]	57.0	39.6	43.7
difference to scenario 1	-	17.4	13.3
research question c.			
land use [thousand hectares]	233.9	165.5	182.4
difference to scenario 1	-	68.4	51.5
research question d. (data for year 2015)			
maximum in-feed [MW]	34,260	26,682	28,182
average in-feed [MW]	8,097	8,100	8,098
average full load hours [h]	1,735	2,312	2,176
load gradient, 1-hour-swing	median / max	median / max	median / max
	270 MW / 3,605 MW	295 MW / 5,483 MW	283 MW / 4,499 MW
research question e.			
gross consumer costs [bn €$_{2018}$]	57.0	44.4	51.3
difference to scenario 1	-	12.7	5.7

Comparing total costs according to Eq. ((13)) (research question a.), we find the additional burden resulting from capacity additions at suboptimal sites to be 17.4 (scenario 2 vs. 1, a reduction of 30 %) and 13.3 bn €$_{2018}$ (scenario 3 vs. 1, a reduction of 23 %). The relatively small difference between scenario 2 and more restricted scenario 3 shows that the cost reduction is relatively robust to changes of available sites. To answer our first research question: an onshore wind support scheme focusing on cost efficiency, and in particular avoiding higher payments for low wind sites, could have reduced costs significantly.

When looking at the causes for the cost savings, we have to consider sites chosen (research question b.) and associated aspects of turbines built. Figure 4 reveals a turbine concentration on good sites in northern Germany in scenario 2, which is also found, albeit less pronounced, in scenario 3. In contrast, capacity in historic scenario 1 is significantly more scattered over Germany. In terms of raster with at least one wind turbine, there are 1,824 raster cells (49 % of raster) used in scenario 1. In contrast, capacity is concentrated at 175 very good raster cells (5 %) in scenario 2 and 451 raster cells (12 %) in scenario 3.

The differences in sites chosen become more evident when comparing the percentage of a raster's land potential used. The majority of raster cells is hardly used at all (less than 1% of potential is used at the end of 2015) in all three scenarios. However, the share of hardly used raster cells increases from 54 % in scenario 1 to 95 % in scenario 2, and 88 % in scenario 3, respectively. At the other end of the scale are top-used raster cells (we define these as at least 90 % use at the end of 2015). Just 97 raster cells (3 % of raster cells) in scenario 1 are top-used; and comparable 81 raster cells (or 2 % of raster cells) in scenario 3. This number increases to 156 raster cells (4 %) in unrestricted scenario 2.[27] Hence, as expected, the concentration of wind turbines is significantly higher in the two benchmarks.

Also, site qualities are much better in the benchmarks. In scenario 1, just 21 % of turbines have more than 2,400 full-load hours. This number is 77 % in scenario 2 and 66 % in scenario 3. Matching historic generation in the benchmarks is thus achieved by exploiting raster cells with high wind speeds.[28]

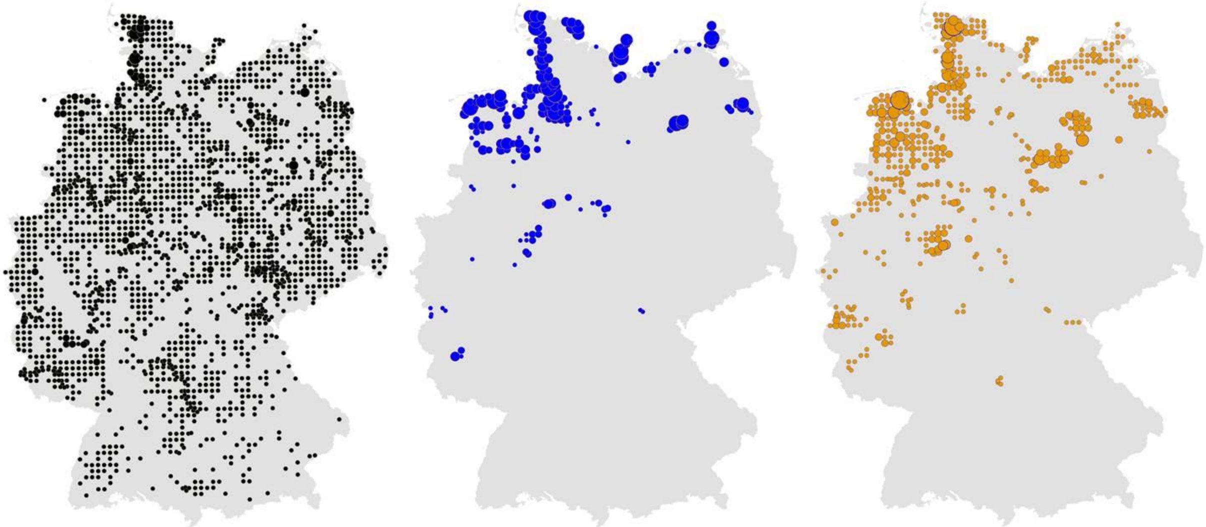


Figure 4: Spatial distribution of turbines (end of 2015): scenario 1 (black), scenario 2 (blue), scenario 3 (orange).

Concentrating capacity additions at good wind sites has additional implications. First, and most obvious, is that significantly fewer turbines need to be built to achieve the desired annual wind generation. The development of installed capacity and increased number of turbines over time is shown in Figure 5 and Figure 6 respectively.[29] Installing significantly fewer turbines (and GW) to achieve the same production is the main reason for the cost reductions achieved in the benchmarks. Second, turbine models built in the benchmarks differ. On average, the turbines in our benchmarks are similar in terms of hub heights. However, turbines in the benchmarks exhibit both larger rotors and higher ratings. Taken together, specific ratings (in watts per swept rotor-area) of newly build turbines recede from 390 W/m^2 (1995) to 330 W/m^2 (2015) in scenario 1, and in our benchmarks from 380 W/m^2 to 320 W/m^2 in scenario 2 and 280 W/m^2 in scenario 3, respectively.[30] Furthermore, Figure 5 and Figure 6 confirm again that model results are robust with regard to the additional constraints in scenario 3. All restrictions can largely be

[27] Land use and capacity per raster and scenario: online supplement, Table 5.
[28] Distribution of (long-run) full-load hours per scenario: online supplement, Table 6.
[29] Capacities and turbine numbers per year and scenario: online supplement, Table 7.
[30] Average configurations of the turbine stock per year and scenario: online supplement, Table 8.

compensated for with a “spill-over” to second-best locations. When the respective threshold is reached, it seems possible to build in different raster cells without installed capacity and costs increasing strongly.

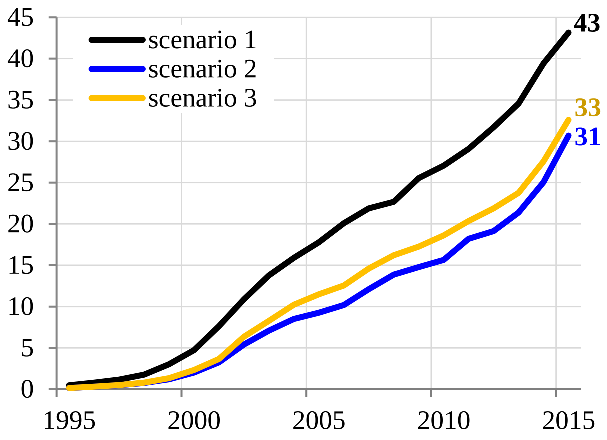


Figure 5: Capacity installed in gigawatts.

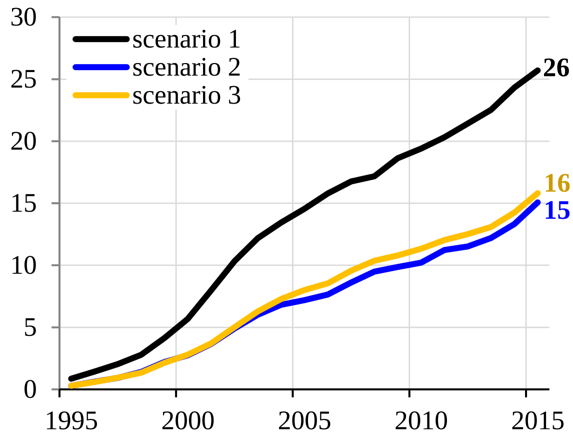


Figure 6: Number of turbines installed in thousands.

The savings in land use (research question c.) are 68,400 (scenario 2 vs. 1) and 57,900 hectares (scenario 3 vs. 1), which is a reduction of 22 % and 29 % respectively.[31] These savings are not proportional to the savings in turbines, since turbines in the benchmarks have larger rotors (requiring more space) than in scenario 1. Further, these savings are not equally distributed within Germany. Instead, *Lower Saxony* and *Schleswig-Holstein*, two primarily rurally states with many good sites, carry 82 % of installed wind capacity in scenario 2, as compared to 34 % in scenario 1, and thus bear most of the land used. Due to restriction 6, this recedes to 60 % in scenario 3. Nonetheless, even in scenario 2, there is just one case (*Schleswig-Holstein)* where the land use exceeds the state-specific threshold of 2 % (cf. constraint 6 in Section 3.1.3).[32] In scenario 3, land use in this state stops at 2 % as constraint 6 binds.

A detailed analysis of generation profiles (research question d.) reveals several interesting insights.[33] First, correlation coefficients of capacity in-feed per hour are high: 0.9 (between scenario 2 and 1), 0.96 (scenario 3 and 1) and 0.98 (scenario 2 and 3)[34]. Overall, we interpret these values as affirmation that assuming constant marginal values of wind (cf. 3.1.2) does not constitute a significant disadvantage.

Second, as shown in Figure 7 (left side) for representative year 2015, the in-feed of scenario 1 is not as evenly distributed as the in-feed of the benchmarks, as the former has few hours with higher and many with lower in-feed.[35] Though average in-feed is nearly identical (8.1 GW, cf. Table 2), absolute peak production is significantly higher in scenario 1: 34 GW as compared to 26 in scenario 2 and 28 GW in scenario 3 (cf. Table 2). The balancing effect of decentralized

[31] Land use per year and scenario: online supplement, Table 9.
[32] Land use per state: online supplement, Table 10.
[33] Hourly in-feed, 2010-2015, per scenario: online supplement, Table 11.
[34] Given the high resemblance of our benchmarks, the latter is not surprising.
[35] Remember that the surface area below each line is equal as annual generation is equal.

in-feed in scenario 1 is seemingly outweighed by the fact that significantly more capacities are necessary to generate the same amount of energy as in our benchmark scenarios. Note that the maximum in-feed is one crucial parameter for grid enforcement. Hence, it is not as clear-cut as one might think that building wind at good sites would require more grid capacity within Germany.

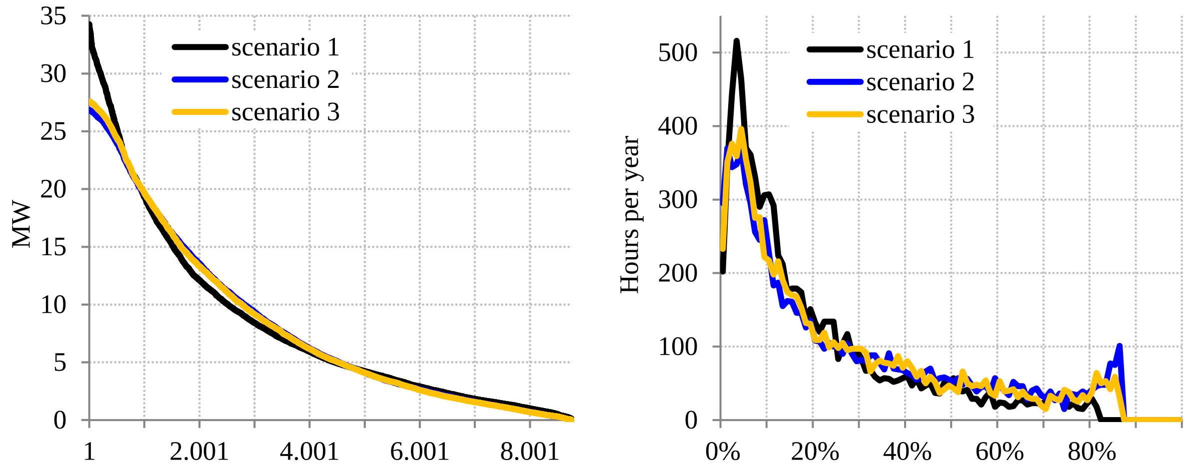


Figure 7: Distribution of the fleet's hourly in-feed in 2015: absolute in-feed in hours (left) and in percent of capacity installed (right).

As capacity installed differs between scenarios, the right side of Figure 7, showing the distribution of capacity used in percent of capacity installed, is even more meaningful. Due to using better sites, the benchmarks exhibit more hours with high utilisation (> 80 %), fewer hours with low utilisation (< 10 %) and a higher utilisation on average. Peak production in scenario 1 is lower, as in the benchmarks, as simultaneity of strong winds occurs less often, which is a consequence of stronger decentralisation.

Third, load gradients are another indicator to compare hourly in-feed. We measure volatility as a rate of change in hourly time steps. Higher load gradients reflect an increased need for flexibility in the power system. Our results are in line with that of Bucksteeg (2018) as maximum load gradients increase with geographical concentration of capacities (cf. Table 2). We find the highest load gradients in scenario 2. Comparing scenario 3 to 1, maximum load gradients differ by around 900 MW, increasing the load gradient of scenario 1 by 25 %.

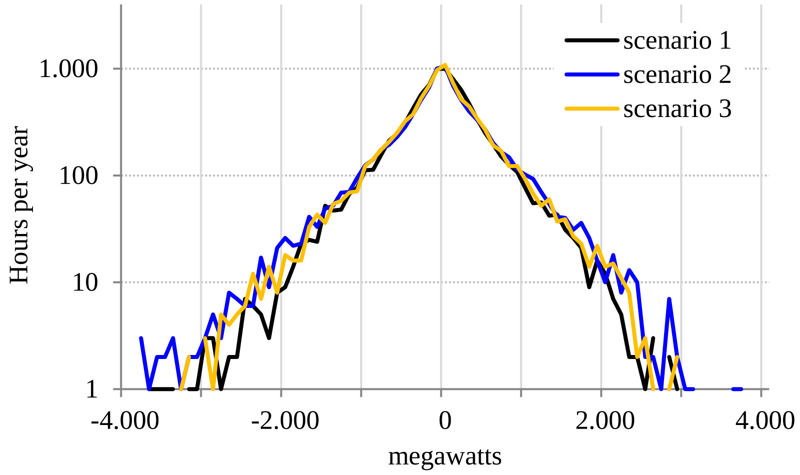


Figure 8: Histogram of the rate of change of capacity [MW] in a one hour time step, year 2015.

Finally, analysing consumer payments (research question e., calculated as described in Section 3.2.4), we find savings for consumers in the two benchmarks. Savings amount to 12.7 bn €$_{2018}$ (scenario 2 vs 1) and 5.7 bn €$_{2018}$ (scenario 3 vs. 1). Hence, limiting producer rents and reducing efficiency in the interest of consumers does not have the desired effect of protecting consumers in the empirical setting analysed in this paper. On the contrary, we find that the efficiency gains of realizing the best wind sites outweigh the increase in producer rents from the consumers' perspective. However, these results have to be seen in the context of our model set-up, assuming e.g. perfect competition.

5 CONCLUSION

In this paper we compare the existing wind capacity build-up in Germany with two benchmark systems, which minimize total generation costs under varying constraints. The first benchmark (scenario 2) restricts capacity additions mostly by available space, the second benchmark (scenario 3) imposes additional constraints, such as limiting the total number of turbines at a raster to twice the number of turbines historically built. In all three scenarios, we compare total costs, number of turbines built, locations, land use, in-feed and consumer welfare.

Our analysis reveals that the capacity build-up in reality might have been much less costly if good sites had been prioritized. Furthermore, a lot of land could have been saved for alternative uses. In terms of costs, we find that the two counterfactual benchmarks are 30 % (17.4 bn€$_{2018}$, scenario 2) and 23 % (13.3 bn€$_{2018}$, scenario 3) cheaper respectively than the historic development. Land use of turbines would have been smaller by a similar percentage. This reveals two things: First, in our view, these reductions in both cost and land use are significant. Second, reductions seem robust as they decrease but not diminish when significant additional constraints are imposed (from scenario 2 to scenario 3). Cost savings exceeding 10 bn€$_{2018}$, are also interesting as this paper – as was already pointed out in the introduction – restricts the technology dimension to onshore wind and the region to Germany alone. Widening either (or even both) of these dimensions would lead to additional cost reductions.

Both cost and land use savings result from an optimized production portfolio in the two benchmarks: best available turbines are built at the best available sites. Real world market designs are unlikely to reach the optimal result as imperfections increase costs somewhat. Further, local land-use regulations and other incentives not systematically focussing on good sites increase costs. The German case is a particularly good example due to the reference yield model paying sites with low wind speeds more money per kWh than sites with high ones. Consequently, capacities are spread out over the country. As a result, costs are significantly higher than they would have been if good wind sites had been prioritized.

Of course, such incentives might be otherwise justified. One reason sometimes cited is grid constraints, which limit the concentration of turbines in a certain region. However, firstly we found that maximal annual wind production would be considerably lower in an efficient capacity built up – as capacity would have more full hours, thus requiring less capacity overall. Second, the reference yield model is an indirect and comparably inefficient tool to address grid constraints. Another argument sometimes raised in favour of the reference yield model is limiting producer rents in an attempt at price discrimination aimed at protecting consumers. However, we found that consumers are actually worse off as a result. The reason is that total welfare gains from a more efficient development both increase producer rents and outweigh the rent shifting from consumers to producers.

In the light of our results, in particular high cost differences resulting from relatively small design changes, we recommend performing thorough quantitative assessments before significant regulatory interventions are implemented. Besides, support mechanisms should prioritize efficiency potentials over incentives for less favourable sites or regional sub-steering of capacities. Otherwise, as is shown in our case, higher costs for society might result without even achieving secondary policy objectives. More efficient results can be incentivized by both the tariff system and land-use regulations. Some aspects of the current energy policy, such as joined auctions for RES capacity (i.e. auctions where both wind and photovoltaic projects can participate) are a step in the right direction. Other aspects of German energy policy are in contrast to the conclusions we have drawn. For example, higher support payments for all sites in the south of Germany (Deutscher Bundestag, 2018) are debated on the state level.

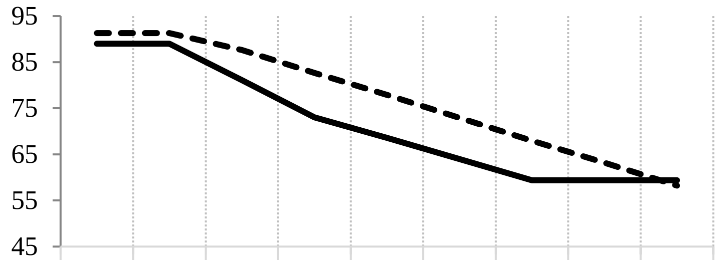
Further research should focus on grid constraints and the value of wind power generation. Both require at least an electricity system dispatch model including all electricity generation, ideally complemented with a grid flow model. In the current analysis, the efficiency gap presents an upper bound of grid costs allowed to retain the cost advantage. Even if grid costs in scenario 3 amounted to 5.6 bn €$_{2018}$, it would still be more efficient to concentrate on good sites. Given our results on the fleet's hourly in-feed in more realistic scenario 3, we find evidence that concentration leads to an increase in volatility, which might raise system costs for growing flexibility needs. Yet, on average, the capacities installed in both benchmarks are more evenly utilized, and – since total capacities are lower overall – absolute peaks are lower than in reality. Given this, it might be possible that grid enlargements were not needed at all.

Also, a quantification of the costs (and contribution to other policy objectives) of variations in the technology and space dimension would be of interest.

APPENDIX A: ADDITIONAL INFORMATION ON THE INCENTIVE TO BUILD WIND AT LOW WIND SITES

In RESA, the incentive to build onshore wind plants at low wind sites was given as follows. During the period of observation, support was paid for 20 years plus the year of commercial start-up. However, support payments varied over the 20-year time horizon. An initial first period with a higher tariff level was followed by a second period with a lower level. Whereas the absolute levels of payments during both periods purely depended on the first year of commercial operation, the time length of the two periods depended on the yield of the turbine deployed as compared to the same turbine type's "reference yield" at a "reference site".[36] Thus, an individual, site-specific yield translated into an individual course of payments paid. The formula defining the time length was set by law.[37]

In August 2014, the formula defining the time length changed for the first and only time during our period of observation. To illustrate this change, Figure 9 shows two lines. Each line depicts an average tariff level (time-length weighted) at different site qualities for a Vestas V90 wind turbine at 105 metres hub height.[38] The dotted line corresponds to a start-up in July[39], the solid line to a start-up in August 2014.[40]



70%	80%	90%	100%	110%	120%	130%	140%	150%	Site quality in reference yield achieved
2149	2456	2763	3070	3377	3684	3991	4298	4605	full load hours
252	247	220	193	167	140	113	87	60	months in initial period, RESA 2000-2014
252	241	192	143	116	88	60	60	60	months in initial period, RESA 2014

Figure 9:Average support level [€/MWh] depending on site quality.

---

[36] The reference site in any RESA-version was defined as "a site determined by means of a Rayleigh distribution with a mean annual wind speed of 5.5 metres per second at a height of 30 metres above ground level, a logarithmic wind shear profile and a roughness length of 0.1 metres" (RESA, 2012). The reference yield was the yield generated in five years at the reference site. To derive the absolute levels of payments, production costs were regularly assessed and the levels fixed by law.

[37] See online supplement, Table 1.

[38] Its reference yield at the reference site is 6.1 GWh in one year.

[39] Initial (basic) support level: 91.3 (47.2) €/MWh.

[40] Initial (basic) support level: 89.0 (49.5) €/MWh.

APPENDIX B: ADDITIONAL INFORMATION ON LAND USE CALCULATION AND POTENTIAL FOR WIND USE

To calculate the land potential for wind energy use in a raster, we use these spatial datasets:

- The landscape model AFIS-ALKIS-ATKIS 250 (1:250,000), provided by the Federal Agency for Cartography and Geodesy to detect infrastructure, settlement, water bodies.
- Open StreetMap Data to account for transport infrastructure.
- Processed Shuttle Radar Topography Mission data (version 4.1) to calculate slope, available at the Centre for Tropical Agriculture consortium for Spatial Information.
- Data on biosphere reserves, national parks, nature parks, conservation areas, landscape protection areas, wetlands provided by the Federal Office of Natural Conservation.

CORINE Land Cover data provided by the European Environment Agency.

Table 3: Synopsis of assumptions on land use of wind turbines.

source	description	land use of an exemplary turbine with 100-metre rotor diameter [hectares]
Umweltbundesamt (2013), Masurowski et al. (2016), Drechsler et al. (2017)	5 rotor diameters in main and 3 in secondary wind direction	11.8
Fraunhofer IWES (2011), BMVI (2015)	4 rotor diameters radial	12.6
Eichhorn et al. (2017)	6 rotor diameters in main and 3 in secondary wind direction	14.1
FfE (2015), **this paper**	**5 rotor diameters radial**	**15.7**
Hau (2008)	8 rotor diameters in main and 3 in secondary wind direction	18.8
McKenna et al. (2014)	8 rotor diameters in main and 5 in secondary wind direction	31.4

Table 4: Synopsis of assumptions on potential for wind energy use in Germany.

source	potential in percent of Germany’s land area
BMVI (2015): differentiated approach	2 %
Matthes et al. (2018)	5 %
Christ et al. (2016)	8 %
Bucksteeg (2018)	6 %
this paper	**8 %**
Büchner et al. (2014)	9 %
BMVI (2015): normative approach	11 %
McKenna et al. (2014)	12 %
Umweltbundesamt (2013)	14 %
Wimmer et al. (2014)	23 %

REFERENCES

Bergek, A.; Jacobsson, S. (2010): Are tradable green certificates a cost-efficient policy driving technical change or a rent-generating machine? Lessons from Sweden 2003-2008, in: *Energy Policy*, 38, pp. 1255-1271, https://dx.doi.org/10.1016/j.enpol.2009.11.001

Boeters, S.; Koornneef, J.B. (2011): Supply of renewable energy sources and the cost of EU climate policy, in: *Energy Economics*, 34, pp. 489-509

Bucksteeg, M. (2018): Modelling the impact of geographical diversification of wind turbines on the requiered firm capacity in Germany, in: *Applied Energy*, 235, pp. 1476-1491, http://dx.doi.org/10.1016/j.apenergy.2018.11.031

Capros P.; Mantzos L.; Parousos L.; Tasios N.; Klaassen, G. (2011): Analysis of the EU policy package on climate change and renewables, in: *Energy Policy*, 39, pp. 1476-1485

Cramton, P.; Ockenfels, A.; Stoft, S. (2015): An international carbon-price commitment promotes cooperation, in: *Economics of Energy & Environmental Policy*, 4(2), pp. 51-64, http://dx.doi.org/10.5547/2160-5890.4.2.aock

de Jager, D.; Klessmann, C.; Stricker, E.; Winkel, T.; de Visser, E.; Korper, M.; Ragwitz, M.; Held, A.;, Resch, G.; Busch, S.; Panzer, C.; Gazzo, A.; Roulleau, T.; Gousseland, P.; Henriet, M.; Bouillé, A. (2011): Financing renewable energy in the European Enegy Market

del Rio, P.; Cerdá, F. (2014): The policy implications of the different interpretations of the cost-effectiveness of renewable electricity support, in: *Energy Policy*, 64, pp. 364-372

Drechsler, M.; Eger, J.; Lange, M.; Masurowski, F.; Meyerhoff, J.; Oehlmann, M. (2017): Efficient and equitable spatial allocation of renewable power plants at the country scale, in: *Nature Energy*, 2, 17124, http://dx.doi.org/10.1038/nenergy.2017.124

Drechsler, M.; Ohl, C.; Meyerhoff, J.; Eichhorn, M.; Monsees, J. (2011): Combining spatial modeling and choice experiments for the optimal spatial allocation of wind turbines, in: *Energy Policy*, 39(6), pp. 3845-3854, https://doi.org/10.1016/j.enpol.2011.04.015

Engelhorn, T.; Müsgens, F. (2018): How to estimate wind-turbine infeed with incomplete stock data: A general framework with an application to turbine-specific market values in Germany, in: *Energy Economics*, 72, pp. 542-557, https://doi.org/10.1016/j.eneco.2018.04.022

Fell, H.; Linn, J. (2013): Renewable electricity policies, heterogeneity, and cost effectiveness, in: *Journal of Environmental Economics and Management*, 66(3), pp. 688-707, https://doi.org/10.1016/j.jeem.2013.03.004

Fischer, C.; Newell, R. (2008): Environmental and technology policies for climate mitigation, in: *Journal of Environmental Economics and Management*, 55(2), pp. 142-162

Frontier Economics; r2b (2013): Effizientes Regime für den Ausbau der EE, Weiterentwicklung des Energy-Only-Marktes und Erhaltung des EUETS, Frontier Economics Ltd, London

Frontier Economics (2014): Technologieoffene Ausschreibungen für Erneuerbare Energien. Ein Bericht für EFET Deutschland. Frontier Economics Ltd, London

Gawel, E.; Lehman, P.; Purkus, A.; Söderholm, P.; Witte, K. (2017): Rationales for technology-specific RES support and their relevance for Germany, in: *Energy Policy*, 102, pp. 16-26,
http://dx.doi.org/10.1016/j.enpol.2016.12.007

Gils, H.C.; Scholz, Y.; Pregger, T.; de Tena, D.L.; Heide, D. (2017): Integrated modelling of variable energy-based power supply in Europe, in: *Energy*, 123, pp. 173-188,
https://doi.10.1016/j.energy.2017.01.115

Goetzke, F.; Rave, T. (2016): Exploring heterogeneous growth of wind energy across Germany, in: *Utilities Policy*, 41, pp. 193-205,
https://doi.org/10.1016/j.jup.2016.02.010

Grothe, O.; Müsgens, F. (2013): The influence of spatial effects on wind power revenues under direct-marketing rules, in: *Energy Policy*, 58, pp. 237-247

Haas, R.; Panzer, C.; Resch, G.; Ragwitz, M.; Reece, G.; Held, A. (2011): A historical review of promotion strategies for electricity from renewable energy sources in EU countries, in: *Renewable & sustainable energy reviews*, 15(2), pp. 1003-1034,
https://doi.org/10.1016/j.rser.2010.11.015

Heptonstall, P.; Gross, R.; Steiner, F. (2017): The costs and impacts of intermittency – 2016 update. A systematic review of the evidence on the costs and impacts of intermittent electricity generation technologies

Hitaj, C.; Löschel, A. (2019): The impact of a feed-in tariff on wind power development in Germany, in: *Resource and Energy Economics*, 57, pp. 18-25,
https://doi.org/10.1016/j.reseneeco.2018.12.001

Jägemann, C.; Fürsch, M.; Hagspiel, S.; Nagl, S. (2013): Decarbonizing Europe's power sector by 2050 – Analyzing the economic implications of alternative decarbonisation pathways, in: *Energy Economics*, 40, pp. 622-636,
http://dx.doi.org/10.1016/j.eneco.2013.08.019

Jägemann, C. (2014): A Note on the Inefficiency of Technology- and Region-Specific Renewable Energy Support: The German Case, in: *Zeitschrift für Energiewirtschaft*, 38, pp. 235-253,
https://doi.org/10.1007/s12398-014-0139-7

Joskow, P.L. (2011): Comparing the costs of intermittent and dispatchable electricity generating technologies, in: *American Economic Review*, 100(3), pp. 238-241

Jung, C.; Schindler, D.; Grau, L. (2018): Achieving Germany's wind energy expansion target with an improved wind turbine siting approach, in: *Energy Conversion and Management*, 173, pp. 383-398, https://doi.org/10.1016/j.enconman.2018.07.090

Klessmann, C.; Rathmann, M.; de Jager, D.; Gazzo, A.; Resch, G.; Busch, S.; Ragwitz, M. (2013): Policy options for reducing the costs of reaching the European renewables target, in: *Renewable Energy*, 57, pp. 390-403, http://dx.doi.org/10.1016/j.renene.2013.01.041

Konetschny, C.; Schmid, T.; Jetter, F. (2017): Potenzielle Leistungsdichte und Stromerzeugungvon Windparks: Anteil der regionalen Windstromerzeugung am Verbrauch für ein "2 %-Szenario", in: Energiewirtschaftliche Tagesfragen, 67(5), pp. 59-62

Kreuz, S.; Müsgens, F. (2017): The German Energiewende and its Roll-Out of Renewable Energies: An Economic Perspective, in: *Frontiers in Energy*, 11(2), pp. 126-134

Lamont, A.D. (2008): Assessing the long-term system value of intermittent electric generation technologies, in: *Energy Economics*, 30, pp. 1208-1231

Lauf, T.; Ek, K.; Gawel, E.; Lehmann, P.; Söderholm, P. (2018): The Regional Heterogeneity of Wind Power Deployment. An Empirical Investigation of Land-use Policies in Germany and Sweden, in: *UFZ Discussion Papers*, Department of Economics, 1/2018

Lehmann, P.; Gawel, .E. (2013): Why should support schemes for renewable electricity complement the EU emissions trading scheme? In: *Energy Policy*, 52, pp. 597-607

Lehmann, P.; Söderholm, P. (2018): Can Technology-Specific Deployment Policies be Cost-Effective? The Case of Renewable Energy Support Schemes, in: *Environmental and Resource Economics*, 71, pp. 475-505, https://doi.org/10.1007/s10640-017-0169-9

Marcantonini, C.; Ellerman, D. (2015): The implicit Carbon Price of Renewable Energy Incentives in Germany, in: *The Energy Journal, International Association for Energy Economics*, 4, https://doi.org/10.5547/01956574.36.4.cmar

McKenna, R.; Hollnaicher, S.; Fichtner, W. (2014): Cost-potential curves for onshore wind energy: A high resolution analysis for Germany, in: *Applied Energy*, 115, pp. 103-115

Meyerhoff, J.; Ohl, C.; Hartje, V. (2010): Landscape externalities from onshore wind power, in: *Energy Policy*, 38, pp. 82-92

Müsgens, F. (2018): Equilibrium Prices and Investment in Electricity Systems with CO2-Emission Trading and High Shares of Renewable Energies, in: *Energy Economics*. Article in press, https://doi.org/10.1016/j.eneco.2018.07.028

Nordensvärd, J.; Urban, F. (2015): The stuttering energy transition in Germany: Wind energy policy and feed-in tariff lock-in, in: *Energy Policy*, 82, pp. 156-165, http://dx.doi.org/10.1016/j.enpol.2015.03.009

OSCE (2009): Framework Conditions and International Best Practices for Renewable Energy Support Mechanisms

Pechan, A. (2017): Where do all the windmills go? Influence of the institutional setting on the spatial distribution of renewable energy installation, in: *Energy Economics*, 65, pp. 75-86, http://dx.doi.org/10.1016/j.eneco.2017.04034

Resch, G.; Farber, T.; Ragwitz, M.; Held, A.; Panzer, C.; Haas, R. (2009): Futures-e. 20% RES by 2020 – a balanced scenario to meet Europe's renewable energy target

Roques, F.; Hiroux, C.; Saguan, M. (2010): Optimal wind power deployment in Europa – A portfolio approach, in: *Energy Policy*, 38, pp. 3245-3256

Schmidt, J.; Lehecka, G.; Gass, V.; Schmid, E. (2013): Where the wind blows: assessing the effect of fixed and premium based feed-in tariffs on the spatial diversification of wind turbines, in: *Energy Economics*, 40, pp. 269-276

Schmitt, M.; Dosch, F.; Bergmann, E. (2006): Flächeninanspruchnahme durch Windkraftanlagen, in: *Raumforschung und Raumplanung*, 64(5), pp. 405-412, http://dx.doi.org/10.1007/BF03184535

Staffell, I.; Pfenninger, S. (2016): Using bias-corrected reanalyses to simulate current and future wind power output, in: Energy, 114, pp. 1224–1239

Sunak, Y.; Madlener, R. (2016): The impact of wind farm visibility on property values: A spatial difference-in-differences analysis, in: *Energy Economics*, 55, pp. 79-91, http://dx.doi.org/10.1016/j.eneco.2015.12.025

Ueckerdt, F.; Hirth L.; Luderer, G.; Edenhofer, O. (2013): System LCOE: What are the costs of variable renewables? In: *Energy*, 63, pp. 61-75, http://dx.doi.org/10.1016/j.energy.2013.10.072

Wang, M.; Zhao, J. (2018): Are renewable energy policies climate friendly? The role of capacity constraints and market power, in: *Journal of Environmental Economics and Management*, 90, pp. 41-60, https://doi.org/10.1016/j.jeem.2018.05.003

Wurster, F.; Hagemann, C. (2018): Two ways to success expansion of renewable energies in comparison between Germany's federal states, in: *Energy Policy*, 119, pp. 610-619, https://doi.org/10.1016/j.enpol.2018.04059

Xia, F.; Song, F. (2017): The uneven development of wind power in China: Determinants and the role of supporting policies, in: *Energy Economics*, 67, pp. 278-286, http://dx.doi.org/10.1016/j.eneco.2017.08.008

Data and law references

BMVI, Federal Ministry of Transport and Digital Infrastructure (2015): Räumlich differenzierte Flächenpotentiale für erneuerbare Energien in Deutschland, https://www.bbsr.bund.de/BBSR/DE/Veroeffentlichungen/ministerien/BMVI/BMVIOnline/2015/BMVI_Online_08_15.html?nn=413102 (accessed 10/08/2018)

BMWi, Federal Ministry for Economic Affairs and Energy (2018): Time series for the development of renewable energy sources in Germany 1990 - 2017

Bundesnetzagentur (2018): Genehmigung des Szenariorahmens 2019-2030, https://www.netzausbau.de/bedarfsermittlung/2030_2019/szenariorahmen2019-2030/de.html

Bundesnetzagentur, Bundeskartellamt (2018): Monitoringbericht 2018, https://www.bundesnetzagentur.de/SharedDocs/Downloads/DE/Allgemeines/Bundesnetzagentur/Publikationen/Berichte/2018/Monitoringbericht_Energie2018.pdf?__blob=publicationFile&v=3 (accessed 01/31/2019)

Büchner, J.; Katzfey, J.; Flörcken, O.; Moser, A.; Schuster, H.; Dierkes, S.; van Leeuwen, T.; Verheggen, L.; Uslar, M.; van Amelsvoort, M. (2014): Moderne Verteilernetze für Deutschland (Verteilernetzstudie). Abschlussbericht. Forschungsprojekt Nr. 44/12, Studie im Auftrag des Bundesministeriums für Wirtschaft und Energie (BMWi)

Christ, M.; Soethe, M.; Bunke, W-D. (2017): Indicator for the current and future socio-ecological burden caused by the expansion of wind energy in German districts - auxiliary values,
https://zenodo.org/record/844604#.XF4Kgf6Wziw

Deutsche Bundesbank (2019): Consumer Price Index, https://www.bundesbank.de/dynamic/action/en/statistics/time-series-databases/time-series-databases/759784/759784?listId=www_s311_lr_vpi (accessed 01/28/2019)

Deutscher Bundestag, Drucksache 14/2776 (2000).

Deutscher Bundestag, Drucksache 19/6155 (2018).

Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG&toc=OJ:L:2018:328:TOC (accessed 03/23/2019)

Eichhorn, M.; Tafarte, P.; Thrän, D. (2017): Towards energy landscapes – “Patchfinder for sustainable wind power locations”, in: *Energy*, 134, pp. 611-621, http://dx.doi.org/10.1016/j.energy.2017.05.053

Einig, K.; Heilmann, J.; Zaspel, B. (2011): Wie viel Platz die Windkraft braucht, in: neue energie 08/2011, pp. 34-37

European Environment Energy Agency, https://www.eea.europa.eu/data-and-maps/data/clc-2006-vector-data-version-2. (accessed 07/01/2017)

Federal Agency for Cartography and Geodesy (Bundesamt für Kartographie und Geodäsie), http://www.geodatenzentrum.de/geodaten/gdz_rahmen.gdz_div?gdz_spr=deu&gdz_akt_zeile=5&gdz_anz_zeile=1&gdz_unt_zeile=1&gdz_user_id=0. (accessed 1 July 2017)

Federal Office of Natural Conservation (Bundesamt für Naturschutz), Dataset available upon request, www.bfn.de

FfE (Forschungsstelle für Energiewirtschaft) (2015): Regionalisierung der dezentralen Stromerzeugung im Netzentwicklungsplan 2025, https://www.netzentwicklungsplan.de/de/regionalisierung-der-dezentralen-stromerzeugung-im-netzentwicklungsplan-2025-zu-kapitel-222-0 (accessed 10/08/2018)

Fraunhofer IWES (2011): Potenzial der Windenergienutzung an Land, Kurzfassung,
https://www.wind-energie.de/fileadmin/redaktion/dokumente/publikationen-oeffentlich/themen/01-mensch-und-umwelt/03-naturschutz/bwe_potenzialstudie_kurzfassung_2012-03.pdf. (accessed 10/08/2018)

Guevara, E.; Jarvis, A.; Reuter, H.I.; Nelson, E. (2008): Hole-filled seamless SRTM data v4. Internal Centre for Tropical Agriculture (CIAT).
http://srtm.csi.cgiar.org. (accessed 07/01/2017)

Hau, E. (2008): Windkraftanlagen. Grundlagen, Technik, Einsatz, Wirtschaftlichkeit, 4th edition. Berlin Heidelberg. Springer Verlag,
https://doi 10.1007/978-3-540-72151-2

IEA (2018): World Energy Outlook 2018

Masurowski, F.; Drechsler, M.; Frank, K. (2016): A spatially explicit assessment of the wind energy potential in response to an increased distance between wind turbines and settlements in Germany, in: *Energy Policy*, 97, pp. 343-350,
http://dx.doi.org/10.1016/j.enpol.2016.07.021

Matthes, C.; Flachsbarth, F.; Loreck, C.; Hermann, H.; Falkenberg, H.; Cook, V. (2018): Zukunft Stromsystem II – Regionalisierung der erneuerbaren Stromerzeugung, WWF Deutschland, Berlin

NASA: Shuttle Radar Topography Mission (SRTM), Digital Elevation Data from the CHIAR Consortium for Spatial Information,
http://gcmd.nasa.gov. (accessed 07/01/2017)

Open StreetMap Data
https://www.openstreetmap.org/ (accessed 07/01/2017)

RESA (Renewable Energy Sources Act) (2012): Act on granting priority to renewable energy sources (Renewable Energy Sources Act – EEG),
https://www.clearingstelle-eeg-kwkg.de/files/node/8/EEG_2012_Englische_Version.pdf (accessed 10/08/2018)

Umweltbundesamt (UBA) (2013): Potenzial der Windenergie an Land,
https://www.umweltbundesamt.de/publikationen/potenzial-windenergie-an-land (accessed 10/08/2018)

Wimmer, D.; Heinemann, C.; Bauknecht, D. (2014): Die Auswirkung räumlich verteilter Windstromproduktion auf den Flexibilitätsbedarf im deutschen Stromsystem, in: Energiewirtschaftliche Tagesfragen, 64(12), pp. 32-35

World Wind Energy Association (2019): Wind Power Capacity Worldwide Reaches 600 GW, 53,9 GW added in 2018,
https://wwindea.org/blog/2019/02/25/wind-power-capacity-worldwide-reaches-600-gw-539-gw-added-in-2018/ (accessed 03/22/2019)