ifo WORKING PAPERS

369
2022

April 2022

Wind Turbine Placement and Externalities

Patrick Hoffmann, Mathias Mier

ifo INSTITUTE
Leibniz Institute for Economic Research
at the University of Munich

Imprint:

ifo Working Papers
Publisher and distributor: ifo Institute – Leibniz Institute for Economic Research at the University of Munich
Poschingerstr. 5, 81679 Munich, Germany
Telephone +49(0)89 9224 0, Telefax +49(0)89 985369, email ifo@ifo.de
www.ifo.de

An electronic version of the paper may be downloaded from the ifo website:
www.ifo.de

ifo Working Paper No. 369

Wind Turbine Placement and Externalities

Abstract

We apply Open Street Map to identify available placement cells and Global Wind Atlas to determine average wind speeds on a 500 x 500m grid in Germany (1.3 million cells). Minimum distances to obstacles such a roads and buildings leave 535,000 potential placement cells. We calculate distance-dependent noise and visibility damages for each placement cell by using property prices for each of the 401 German counties. We minimize the sum of externalities and project cost given a certain expansion target of average power output, thereby allowing to build two different turbine types. The externality share is 13% for the first 3,600 turbines and 52% with total damages of 293 billion e when installing 83,000 turbines (349 GW rated power). The externality share grows up to 311% with total damages of 1,409 billion e when not considering externalities in the placement process.

JEL Code: C61, H23, Q52, R14
Keywords: Wind turbine, placement, property prices, externality, noise, visibility

Patrick Hoffmann[a], Mathias Mier[b]

[a] ifo Institute for Economic Research at the University of Munich, Poschingerstr. 5, 81679 Munich
[b] Corresponding author: Dr. Mathias Mier, mier@ifo.de, ifo Institute for Economic Research at the University of Munich, Poschingerstr. 5, 81679 Munich

Declaration of interests: none.

CRediT author statement. Patrick Hoffmann: Conceptualization, Data curation, Methodology, Investigation, Visualization, Writing - Original Draft; Mathias Mier: Conceptualization, Methodology, Investigation, Visualization, Writing - Original Draft.

1. Introduction

Onshore wind power is the most promising technology when it comes to decarbonizing electricity generation and meeting rising electricity (and hydrogen) demand of other sectors (transport, mobility, heating, industry). Assuming optimistic technological projections and carbon neutrality, Europe's 2045 electricity generation share from onshore wind power is 63%, reflecting an expansion of wind power from around 160 GW in 2020 to almost 1,400 GW in 2045, dominated by onshore wind expansion (Mier et al., 2021). Finding sufficient space for wind turbines is challenging in densely populated world regions such as Europe because the available potential with reasonable wind speeds is naturally limited and additionally restricted by already existing roads, railways, waterways, bodies of water, natural reserves, and, most importantly, buildings. New wind turbines often need to be placed in the direct proximity of residential properties due to a lack of windy spots in unpopulated areas. Local externalities from wind turbines, namely noise and visibility, constitute disamenities for local residents and foster resistance against wind power. Placing wind turbines in accordance with potential disamenities would in turn enhance local acceptance of wind turbine projects. Moreover, compensating local residents for the externalities might be a way to overcome the lack of social acceptance. We deliver the algorithm to place turbines not only in the best wind spots but also under consideration of externalities and enable to calculate appropriate compensation payments.

Wind turbines produce noise and shadow flickering that might come at structural health cost. Moreover, some people experience cost from a perceived disfigurement of the landscape when turbines are visible. Those indirect cost are externalities that are not carried by firms running wind turbines but rather by the local population. The main challenge is the quantification of those damages. The literature considers several approaches. The first looks at stated preferences from local residents. Klæboe and Sundfør (2016) ask how residents perceive nearby wind turbine projects. Groothuis et al. (2008), Meyerhoff et al. (2010), and Brennan and Van Rensburg (2016) ask residents how much they are willing to pay to avoid or decrease their exposure to wind turbine externalities. The quality of the results heavily relies on a carefully chosen survey design. For instance, those willingness-to-pay questions are mostly concerned with hypothetical scenarios, making it difficult to obtain good estimates of the actual preferences. A different strand of the literature thus looks at revealed preferences as measured by the changes in local property prices (Heintzelman and Tuttle, 2012, Hoen et al., 2015, Gibbons, 2015). The idea of this approach is that properties in the vicinity of a wind turbine are affected by turbine externality. This effect, if it exists, should then be reflected in the respective property value. If this holds true, then local property prices can be used to reveal actual rather than stated preferences. Apart from these preference-based assessment methods, a different strategy is to quantify the external cost by measuring the direct health impact (e.g. Knopper and Ollson, 2011, WHO, 2018, Freiberg et al., 2019). However, people are generally aware of potential health risks associated with nearby wind turbines so that those costs could already be priced (in property values). For our calibration of noise and visibility damages, we decide for the revealed preference approach because it best coincides with the available data on property prices. Jensen et al. (2014) and Heintzelman and

Tuttle (2012) find quite substantial negative externalities, yielding damages of 15 to 20% of the property value for turbines very close to buildings. Gibbons (2015) and Dröes and Koster (2016) find more moderate property price damages. Vyn and McCullough (2014) and Hoen et al. (2015) do not even find significant effects.

Our objective is to place an exogenous given amount of wind turbines at lowest cost, thereby considering diverging wind speeds and wind turbine externalities that arise from noise as well as visibility. We choose a cell size of 500 × 500m to account for minimum distances between wind turbines and allow to place only one turbine exactly in the middle of that cell. Global Wind Atlas (DTU, 2020) delivers the average wind speed of such a cell by converting the Global Wind Atlas resolution into our cell size. We further use Open Street Map (OSM, 2020) to identify potential placement cells by defining minimum distances from the middle of a cell to buildings, roads, waterways, or nature reserves as well as exclude cells with existing turbines. We take Germany as example region with around 1.3 million cells. Minimum distances reduce available placement cells to 535,000. We further allow for different turbine types (ENERCON, 2015, 2019) with diverging project cost (Wallasch et al., 2015), and take county-level property prices (Kempermann et al., 2019) to determine externalities.

Optimal placement of wind turbines (e.g., Ituarte-Villarreal and Espiritu, 2011, Rodman and Meentemeyer, 2006, Zergane et al., 2018) nor the quantification of specific noise or visibility damages (e.g., Jensen et al., 2014, Dröes and Koster, 2016) are new to the literature.[1] However, our contribution is the first considering noise and visibility damages in the exact placement of wind turbines. We quantify results by using Germany as example region but our algorithm is suitable all over the world with reasonable good Open Street Map and property price data. Our algorithm enables to calculate potential damages (and required compensations) for local residents, which are considerable. For our example region Germany, optimal placement of wind turbines (considering damages from noise and visibility of wind turbines) leads to a structurally different selection of cells than sub-optimal placement (that neglects those damages). In particular, the externality share for expanding 100 GW in average power output terms (876 TWh generation potential or 349 GW rated power) is 52% (damages of 293 billion €) under optimal placement but 311% under sub-optimal placement (1,409 billion €).

The next section introduces our modeling strategy containing placement assumptions, the calculation of noise and visibility damages, as well as our objective. Section 3 shows underlying data and further assumptions of the placement process. Section 4 presents results by focusing on the difference between considering and not considering externalities in the placement process. Section 5 concludes.

[1] Rodman and Meentemeyer (2006) considers land use issues to evaluate proposed wind power projects. Ituarte-Villarreal and Espiritu (2011) and Zergane et al. (2018) focus on the optimal placement of turbines in wind farms.

2. Modeling Strategy

One cell, one turbine. Optimal placement of wind turbines (even in wind farms) requires distances between turbines of three to five times the rotor diameter (Lütkehus et al., 2013). Given rotor sizes of 115m, we would have minimum distances of turbines of 345–575m. Therefore, it is unnecessary to reduce the cell resolution below a certain level and it is also unnecessary to allow for more than one wind turbine per cell. We decide for cell sizes of 500×500m and place the respective turbine always in the middle of the cell. The distance to a turbine in the neighboring cell would then be 500m and thus a good proxy for closest possible placement of wind turbines.

No-placement areas. We allow for turbine placement with a minimum distance to buildings of at least 250m. Further no-placement areas are calculated for roads, railway tracks, waterways and body's of water, natural reserves, and specific geological conditions. We intersect no-placement areas with the wind raster cells. R-tree spatial indexing removes cells whose center lies in those no-placement area (Guttman, 1984).

Impact zones. We draw circulars in 250m steps around each building until we reach the *maximum impact distance* of 2,500m (Jensen et al., 2014). The lower and upper bound of neighboring circulars comprise an impact zone. We then count intersections from those impact zones with the center of potential placement cells. For example, intersection counts of 10 for the first impact zone ranging from 250 to 500m and 20 for the second impact zone (500 to 750m) mean that 10 buildings would be affected within the first impact zone and 20 within the second one. This allows to calculate cell-specific externalities by multiplying the number of affected buildings for each impact zone by its respective damage. The respective damage follows from the distance of the turbine to the impact zone. We always calculate the damage of an impact zone by assuming the average distance of the turbine to the respective impact zone (375m for the first impact zone, 625m for the second impact zone, ..., 2,375m for the last impact zone).

Average power output. We allow to build different turbine types j. Average wind power output P is a function of cubic (average) wind speed v, rotor swept area πr^2, air density ρ, and the power coefficient C_P. Wind speed is location-specific, rotor swept area is turbine-specific, and the power coefficient is both location- and turbine-specific.[2] Following from the equations for kinetic energy and the mass flow rate and denoting cells by subscript i, we calculate the location- and turbine-specific *average power output* as

$$P_{i,j} = \frac{1}{2} \cdot v_i^3 \cdot \pi r_j^2 \cdot \rho \cdot C_{P_{i,j}}. \tag{1}$$

[2]Note that the power output is capped at P_j^{max}, that is, when wind speeds exceed a certain level. However, average wind speeds never exceed levels so that $P_{i,j} < P_j^{max}$. We account for the fact that wind speeds are sometimes so high that either production is capped at P_j^{max} or even zero (when wind speeds are above the level where wind turbine operating) by assuming that the best wind spot in the area delivers 4,000 full-load hours. We then scale power output of each cell-turbine-combination with the factor that would be necessary to scale the best wind spot.

Visibility damage. We assume that visibility damages arise for each building, that there is a distance-independent damage VD_{fix}, and a variable damage VD_{var}. No damage occurs when the distance of turbine to impact zone exceeds 2,500m. Denote impact zone by subscript z so that d_z is the distance of a turbine to a specific impact zone. The zone-specific visibility damage VD_z for considered impact zones (within 2,500m of the center of potential placement cells) follows from

$$VD_z = VD_{fix} + \frac{VD_{var}}{100} \cdot \max[0; 2,500 - d_z]. \tag{2}$$

We assume that the distance-independent visibility damage is 3.15% (of the property value) and the distance-variable damage is 0.24% that vanishes after the last impact zone (bounds of 2,250m or 2,500m, respectively) (Jensen et al., 2014). Thus, visibility damages are $3.15\% + 0.24\% = 3.39\%$ in the last impact zone and $3.15\% + 22.5 \cdot 0.24\% = 8.55\%$ in the first impact zone (bounds of 250m or 500m, respectively).[3]

Noise damage. The noise damage follows from the sound pressure level SPL (in dB) from turbine type j in impact zone z and the specific noise damage per noise group g.[4] The sound pressure level depends on the sound pressure of the emitting source (here, turbine) L, the turbine height h, and the distance d_z:

$$SPL_{z,j} = L_j - 10 \cdot \log_{10}((\frac{d_z}{100})^2 + (\frac{h_j}{100})^2) - 11dB + 1.5dB - \frac{\sqrt{(\frac{d_z}{100})^2 + (\frac{h_j}{100})^2}}{500}. \tag{3}$$

The sound pressure level is highest at the turbine. It decreases with distance (of a the impact zone) and turbine height (second term in Equation (3)). The values 11dB and 1.5dB represent the distance correction and terrain correction constants, respectively (DEPA, 2011, Jensen et al., 2014). The last term is the air absorption correction, which again depends on distance and height.

Now turn to the noise damage per group. NG_g is the specific noise damage per noise group and I_g the interval of the respective group (in dB). The noise group 0 to 20dB is used as the reference category, i.e., noise below a threshold of 20dB inflicts no damage. This happens for the above calculation framework at a distance of about 3000m, that is, even in the last impact zone there is a small noise damage. Relevant for our calculations are then the noise groups 20 to 30dB, 30 to 40dB, and 40 to 50dB. The impact zone- and turbine-specific noise damage ND follows from

$$ND_{z,j} = NG_g \cdot SPL_{z,j} \quad \forall SPL_{z,j} \in I_g. \tag{4}$$

[3]The visibility (damage) of a turbine should indeed depend on the turbine height and the rotor diameter. However, no study distinguishes visibility damages per turbine height and we thus refrain from accounting for the complexity of that when we cannot calibrate for it. Moreover, turbines are generally visible for more than 2,500m and sometimes even for more than 50km depending on the shape of the area, but Jensen et al. (2014) found significant damages only within 2,500m.

[4]Noise (in dB) is not a linear scale, i.e., doubling the dB level does not mean that the noise is double as high and/or the related damage is doubled.

Total cost. The total cost per turbine in each cell $C_{i,j}$ can be calculated by aggregating project cost PC, visibility damages, and noise damages over all impact zones and multiplying with the number of buildings n that are affected in the respective impact zone z when placing a turbine in cell i:

$$C_{i,j} = \sum_z n_{i,z}(VD_z + ND_{j,z}) + PC_j. \tag{5}$$

Optimization problem. We can now define the optimization problem as mixed-integer problem. $t_{i,j}$ is the mixed-integer variable that decides to place turbine type j in cell i (value of 1) or not (0). Note that the number of decision variables increases by the number of raster cells for each additional turbine type and by the number of turbines for each additional raster cell. Thus, increasing the number of raster cells is rather an issue than increasing the number of turbines. The cost depend on the turbine type and externalities of each potential turbine location, but are independent of the average power output. We enforce placement in the best wind spots by using an expansion target T that contains average power output of the respective locations, i.e.,

$$\min_{t_{i,j}} \sum_i \sum_j C_{i,j} \cdot t_{i,j}, \qquad \text{s.t.} \tag{6}$$

$$\sum_i \sum_j P_{i,j} \cdot t_{i,j} \geq T, \tag{7}$$

$$\sum_j t_{i,j} \leq 1 \quad \forall(i), \tag{8}$$

$$t_{i,j} \in \{0,1\} \quad \forall(i,j). \tag{9}$$

Equation (6) is the minimization problem. Equation (7) constrains expansion by setting a quantity target. Note that the quantity target depends on average power output $P_{i,j}$ and not the maximum power output per turbine or the rated power, respectively. This formulation keeps the optimization as simple as possible and the outcome of the expansion constraint can later re-calculated in rated power units. Equation (8) ensures that only one turbine is placed per cell. Equation (9) defines $t_{i,j}$ as binary variable that can either take the value 0 (no placement) or 1 (placement in the respective cell).[5]

3. Calibration

3.1. Potential placement cells

We use Germany as example region to quantify our results and obtain around 1.3 million cells spacing 500 × 500m. We allow for turbine placement (in the middle of the respective cell)

[5]We process data and solve the optimization problem by using *Python*. We use the *Gurobi* solver for the optimization task. All necessary codes are available at GitHub: https://github.com/Patrick-Hoffmann/WIPLEX.

with a distance to buildings of 250m. We follow Lütkehus et al. (2013) and calculate other no-placement areas for roads (80 to 100m)[6], railway tracks (250m), waterways and body's of water (65m), and natural reserves (200m). These buffer zones do not fully reflect the varying distance recommendations in each German federal state. For example, the 250m distance to buildings is less restrictive than the 1,000m minimum distance recently discussed in Germany or the 10×height rule (when there is no agreement on closer turbines between municipality and turbine provider) which is already in place in Bavaria (article 82(1) BayBO). However, we opt for those values to keep consistency across different regions and to increase the comparability of the results. In addition, we use data on existing and operating wind turbines from BNA (2020) to factor out cells where wind turbines have already been build. As buffer distance for existing wind turbines, we choose a range of five times the rotor diameter, which is the distance used in Lütkehus et al. (2013) for turbines standing in prevailing wind direction. All distance related calculations are conducted in the ETRS89/UTM zone 32N coordinate reference system.

We further exclude all maritime regions using the NUTS1 German boundaries obtained from BKG (2020) and very mountainous terrains. Intuitively, it is infeasible or too costly, respectively, to install wind turbines in certain locations such as mountains that are very remote and face an exceedingly steep terrain. The difficulty in assessing this terrain factor is that it does not only depend on the conditions of the cell itself but also on neighboring cells. For example, consider a raster cell on a mountain plateau. This cell might be very suitable for turbine placement. If the surroundings are included, however, one might conclude that building a turbine on the plateau would not be optimal. Due to the difficulty in making these exact local terrain considerations for each raster cell under consideration, we look at existing turbines and the altitude in which they are build. Checking the altitude for roughly 26,000 turbines in BNA (2020) using the digital terrain model results (BKG, 2020) yields that existing turbines in Germany are found up to 1,521m above sea level. We thus exclude all cells which lie higher than this value.[7] Finally, we remove raster cells with very low average wind speeds (here, 3 m/s) that are outside of the interval where wind turbines are operative.

We obtain a final raster cell set that reduces the initial number of cells to 535,477. We refrain from showing the impact of each distance assumptions due to overlapping effects, that is, some cells are excluded by multiple reasons. However, the largest limiting factors are the distance zones for roads and buildings.

Figure 1 shows average wind speeds measured for the 100m (left) and 150m (right) layer. Wind speeds follow from Global Wind Atlas (DTU, 2020) that allows to derive wind speeds on 250×250m grid. For later calculations, we take the average of four "wind raster cells" to obtain the wind speed for each potential placement cell.[8] Raster cells along the shore line in Northern Germany

[6]We choose a distance of 100m for all major roads such as motorways, primary, secondary and tertiary roads. For all other roads, the minimum distance requirement is 80m.

[7]This limiting factor should be reconsidered when conducting such an analysis in very mountainous countries like Austria or Switzerland.

[8]We use bilinear resampling to generate the 500 × 500m grid. Bilinear resampling calculates the weighted

experience highest average wind speeds. Lowest wind speeds correlate with mountainous regions in Southern Germany, but also in flatter regions in Central Germany wind speeds are generally lower than in the north. In particular, the proximity to the Northern or Baltic sea, respectively, improves wind speeds tremendously. Moreover, average wind speeds are fundamentally higher for the 150m layer. The difference (in average wind speeds) between Northern and Southern Germany even increases with the 150m layer.

Figure 1: Average wind speeds in heights of 100m (left) and 150m (right)

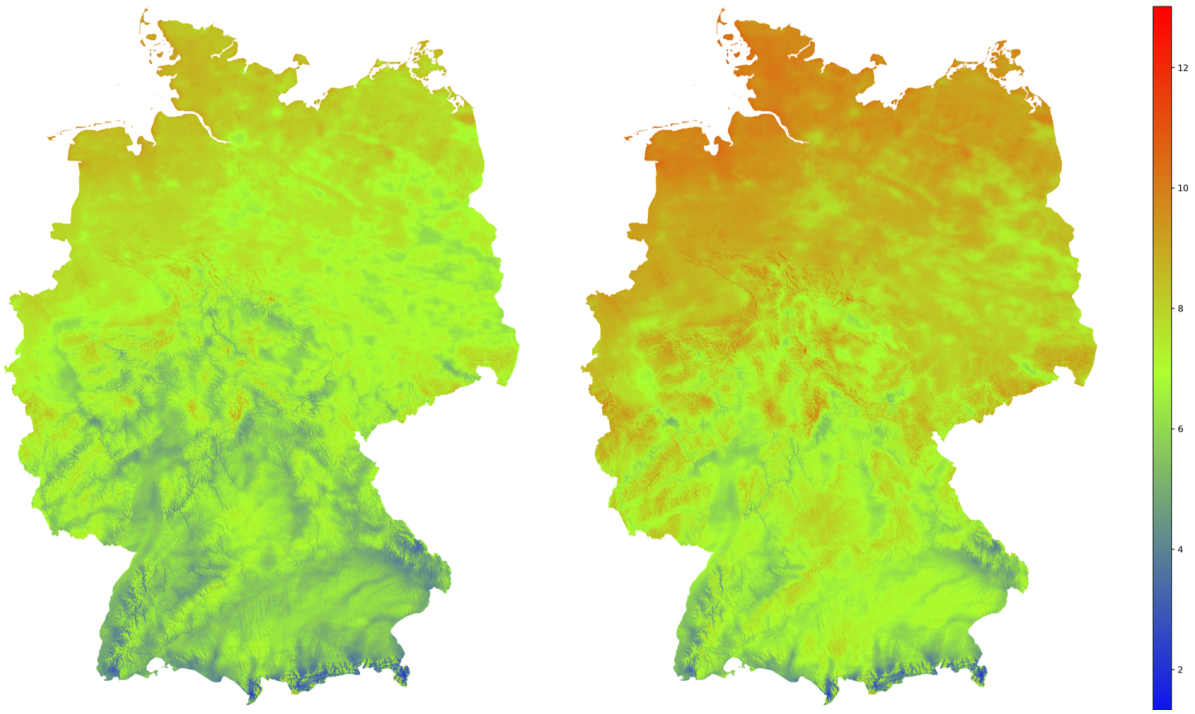
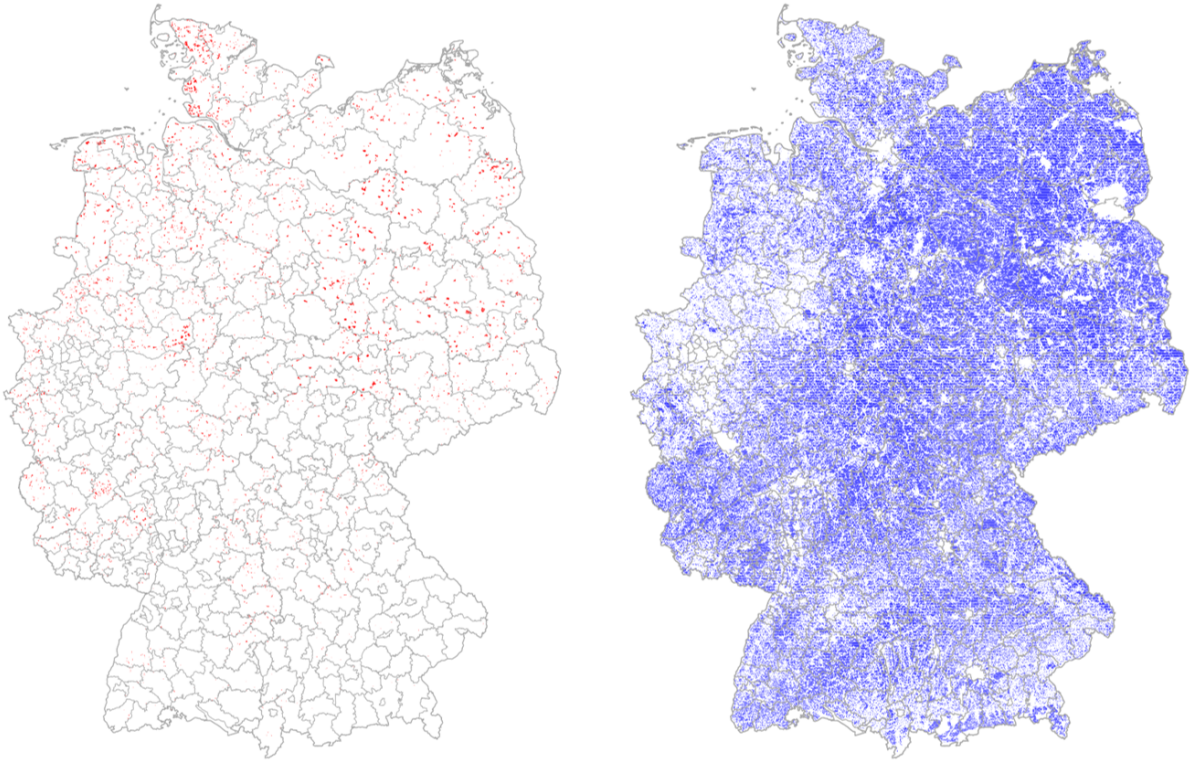


Figure 2 shows existing turbines (left) and resulting potential placement cells (right) in Germany. Existing turbines does not fully reflect the distribution of wind speeds. Most wind turbines are indeed in Northern Germany but the dispersion is far more diverse than the distribution of wind speeds would suggest. However, the past subsidization scheme in Germany indeed aimed for spatially harmonized distribution of wind turbines by paying a higher subsidy for less windy spots. The resulting potential placement cells add the last piece. Observe that there are almost no feasible spots left in metropolitan areas such as Berlin (lower white area in Eastern Germany), Hamburg as well as Bremen (in Northern Germany), Munich (white area in South-Eastern Germany), Stuttgart (white area in South-Western Germany), and the densely populated area in Western Germany containing Rhineland, Ruhr area, and Münster. Additionally, the mountainous

average of the four closest cells of the previous raster for each new cell where the weights correspond to the cell center distance.

areas in South-Eastern Germany are reflected as well. Moreover, nature reserves such as the one in Barnim (upper white area in Eastern Germany) restrict placement as well. Moreover, the areas with best wind speeds in North-Western Germany have fewer placement cells available than slightly worse spots in North-Eastern Germany because existing turbines restrict placement and the area is more densely populated (with buildings and roads). However, there are plenty of possible spots left. Assuming a rated power of 4.2 MW per turbine leaves a potential of 2,249 GW when every potential placement cell is indeed eligible for turbine placement.

Figure 2: Existing wind turbines (left, count: 24,818) and potential placement cells (right, count: 535,477) in Germany

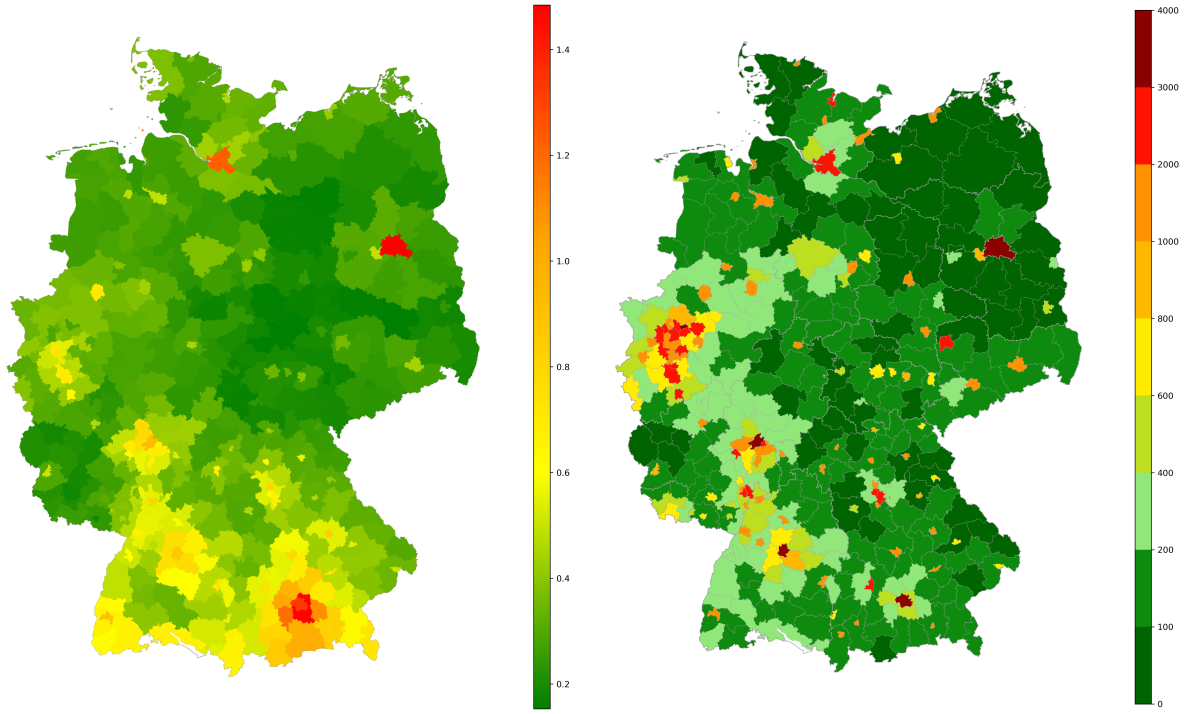


3.2. Property prices

Visibility and noise damages are measured in per cent of property prices. The underlying mechanisms assumes a permanent devaluation of properties. We obtain county-specific house prices for residential properties from Kempermann et al. (2019) and take them as proxy for property prices in the respective county. Figure 3 shows average house prices for residential properties (left) and the population density for each county in Germany. Observe that cities experience structurally higher prices than surrounding areas. In particular, Hamburg, Berlin, and Munich show distinguishing effects to their neighboring areas. However, there are anyway (almost) no placement cells available in cities and wind speeds are also not as good as for less urbanized areas.

In general, prices are structurally higher in Southern Germany than in Northern Germany and also higher in Western Germany than in Eastern Germany. The first fact coincides with higher wind speeds in Northern Germany (compared to the south of Germany) but the second one not completely since (at least) in North-Western Germany wind speeds are structurally higher than in Eastern Germany. Moreover, the very good wind spots in Northern Germany close to the Northern sea including the island Sylt experience higher prices than, for example, areas in North-Eastern Germany, although coastal areas seem to have higher prices than more inland lying regions. Lowest prices are indeed observable in the Eastern part of Germany further away from the metropolitan area of Berlin. When looking at population densities, observe that metropolitan areas surrounding cities face structurally higher densities. Note that the scale of population density is not linear to really extract which areas might have higher population densities. The general pattern shows lower densities in Eastern Germany and also in Northern Germany compared to its Western and Southern parts.

Figure 3: Average house prices for residential properties (left, in million €) and population density (right, inhabitants per km^2) for each German county



3.3. Average power output

We consider two turbine types manufactured by ENERCON, the single largest turbine supplier in Germany with a total current market share of about 43.53% (BNA, 2020). Table 1 provides basic information on those types. Type-1 has a hub height of 92m and a rotor diameter of 115.7m,

leading to a rated power (maximum output) of 3 MW. Type-2 is 50% higher (135m) and has a rotor diameter of 127m, resulting in rated power of 4.2 MW. The average rated power of turbines build since the beginning of 2019 is 3.3MW (BNA, 2020). Thus, the two types are good representatives of turbines recently (Type-1, 3 MW) and currently (Type-2, 4.2 MW) build in Germany. The Global Wind Atlas (DTU, 2020) provides average wind speeds and air densities over a 10-year time period on a 250×250m grid covering all of Germany. We use the 100m layer for the power output calculation of Type-1 and the 150m layer to calculate the power generated of Type-2. Note that the power coefficient also depends on air densities. However, we assume that C_P does not substantially change with small changes in the air density. We thus use the power coefficient as provided by ENERCON (2015, 2019). Cut-in and cut-out wind speeds are not used in our calculation but are added for sake of completeness. Remember from the optimization problem in Section 2 that project cost do not decide where the respective turbine is build but rather determine the dominant turbine type in combination with the average power output calculated from Equation (1). We use estimates on project cost (including investment cost and extra cost for grid connection) from Wallasch et al. (2015). Using their estimates, the project cost of the Type-1 turbine are 4.3 million € (1,433 €/kW) and the one of Type-2 are 6.82 million € (1,623 €/kW).

Table 1: Basic information of considered turbine types

	Type-1	Type-2
Rated power (MW)	3	4.2
Rotor diameter (m)	115.7	127
Hub height (m)	92	135
Cut-in wind speed (m/s)	2.5	2.5
Cut-out wind speed (m/s)	28-34	28-34
Cost (million €)	4.30	6.82
Cost (€/kW)	1,433	1,623
Sound pressure level dB(A)	105.5	106.1

Information depends on ENERCON (2015), ENERCON (2019), and Wallasch et al. (2015). Type-1 denotes turbine model E-115 and Type-2 model E-126-EP4.

3.4. Noise and visibility damages

Table 1 also provides information on the sound pressure level at the emitting source (turbine and rotors). We use this information together with Equation (3) to calculate the sound pressure level of the two turbine types for each impact zone. Remember that Jensen et al. (2014) provides noise damages in per cent of property prices per noise group in 10 dB steps (20–30 dB, 30–40 dB, 40-50 dB, ...). We thus calculate the average sound pressure level per impact zone and then derive the inflicted damage from the respective noise group. Table 2 shows resulting sound pressure levels for each impact zone. Observe that the sound pressure level of Type-2 is only slightly higher than the one of Type-1 at 106.1dB, suggesting that the noise damage might be similar across turbine types. Table 2 supports this suggestion by also presenting the damage (in per cent of property

prices). Indeed, the sound pressure level is slightly higher for the Type-2 turbine in each impact zone but the magnitude of differences is so small that the turbine noise externalities is (on average) in the same noise group. In particular, the first impact zone ranging from 250 to 500m belongs to the noise group 40 to 50 dB with damages of 6.69%. The four impact zones from 500 to 1500m belong to the noise group 30 to 40 dB with damages of 5.5%. Finally, the remaining four impact zones from 1500 to 2500m face damages of 3.07% which represent the noise group between 20 to 30 dB.

Table 2: Sound pressure level, noise, visibility, and total damages by impact zone and turbine type

Impact zone	Sound pressure level (dB) Type-1	Type-2	Noise damage	Visibility damage	Total damage
250–500m	43.4	43.7	6.69%	8.25%	14.94%
500–750m	38.7	39.2	5.50%	7.65%	13.15%
750–1000m	35.3	35.9	5.50%	7.05%	12.55%
1000–1250m	32.7	33.2	5.50%	6.45%	11.95%
1250–1500m	30.5	31.0	5.50%	5.85%	11.35%
1500–1750m	28.5	29.1	3.07%	5.25%	8.32%
1750–2000m	26.8	27.4	3.07%	4.65%	7.72%
2000–2250m	25.2	25.8	3.07%	4.05%	7.12%
2250–2500m	23.7	24.3	3.07%	3.45%	6.52%

Visibility damages follow from Equation (2). Sound pressure levels (SPL) follow from Equation (3). Noise damages follow from Jensen et al. (2014).

We can now add visibility damages by applying Equation (2). Remember that visibility damages are assumed to be independent of hub heights and rotor diameters in accordance with the findings of Jensen et al. (2014). Visibility damages are 8.25% in the closest impact zone and 3.45% in the last one. In total, visibility damages are slightly higher than noise damages. Total damages are found to be in the range of 6.5 to 15%. For example, assuming that three properties worth 500,000 € are each affected in the closest impact zone, the total damage would amount to 224,100 € which increases project cost by 5.13% (Type-1) or 3.29% (Type-2), respectively. Note that both turbines have the same externalities (in € terms) but Type-2 is more expensive (and generates more electricity due to a higher rated power) resulting in a lower externality share.

4. Results

We now present results for expansion scenarios from 5 to 100 GW (in average power output terms) by focusing on the difference between *optimal placement* of turbines (considering externalities in the placement process as discussed in the two prior sections) and *sub-optimal placement* (neglecting the existence of externalities in the placement process).

4.1. Turbine types

For both specifications, we calculate the mixture of turbines (Type-1 or Type-2), the resulting rated power of the turbines installed (in GW), and the full-load hours (FLH, in hours). Table

3 summarizes results. Start with optimal placement. The average FLH of the fleet of turbines ranges from 2,883 (for 5 GW expansion target, reflecting 15 GW rated power) to 2,507 (for 100 GW expansion target, reflecting 349 GW rated power). Type-1 is barely build. In particular, 57 turbines for 5 GW expansion target is the maximum across different targets. For comparison, there are 3,577 Type-2 turbines for 5 GW expansion and 83,181 GW for 100 GW expansion.

Table 3: Number of turbines wit rated power and full-load hours for different expansion targets for optimal (considering externalities) and sub-optimal (neglecting externalities) placement

Expansion	Optimal placement					Sub-optimal placement				
Average (in GW)	Rated (in GW)	FLH	Type-1	Type-2	Total	Rated (in GW)	FLH	Type-1	Type-2	Total
5	15	2,883	57	3,577	3,634	12	3,522	2,344	1,287	3,631
10	32	2,734	33	7,604	7,637	25	3,477	3,033	3,832	6,865
15	49	2,666	17	11,721	11,738	39	3,411	4,473	5,978	10,451
20	67	2,625	18	15,879	15,897	52	3,347	6,685	7,689	14,374
25	84	2,598	24	20,053	20,077	66	3,300	8,772	9,535	18,307
30	102	2,578	22	24,259	24,281	80	3,277	9,926	12,007	21,933
35	120	2,565	28	28,438	28,466	94	3,260	10,680	14,764	25,444
40	137	2,556	26	32,624	32,650	108	3,245	11,245	17,674	28,919
45	155	2,548	25	36,814	36,839	122	3,233	11,532	20,791	32,323
50	172	2,542	24	41,002	41,026	136	3,224	11,361	24,230	35,591
55	190	2,538	25	45,184	45,209	150	3,216	10,807	27,946	38,753
60	208	2,531	34	49,411	49,445	164	3,211	9,824	31,962	41,786
65	225	2,527	35	53,619	53,654	178	3,204	8,646	36,138	44,784
70	243	2,524	35	57,813	57,848	192	3,195	7,700	40,200	47,900
75	261	2,521	36	62,020	62,056	206	3,184	6,842	44,235	51,077
80	278	2,518	21	66,248	66,269	221	3,173	6,189	48,170	54,359
85	296	2,515	22	70,472	70,494	236	3,160	5,667	52,048	57,715
90	314	2,512	21	74,722	74,743	250	3,148	5,189	55,929	61,118
95	332	2,509	15	78,948	78,963	265	3,135	4,812	59,769	64,581
100	349	2,507	15	83,181	83,196	281	3,122	4,512	63,590	68,102

The expansion target refers to *average* power output of installed turbines (in GW) and is the same for optimal and sub-optimal placement. Rated power of installed turbines (in GW) calculates from the number of turbines placed and is different for optimal and sub-optimal placement due to the population of spots with different wind speeds. The same holds true for corresponding FLH (that follow from average power divided by rated power and multiplied by 8760) and number of turbines (per type).

Now turn to sub-optimal placement. Here, the average FLH are structurally higher (3,522 for 5 GW expansion and 3,122 for 100 GW expansion), with structurally lower rated power values (12 GW for 5 GW expansion and 281 GW for 100 GW expansion). Sub-optimal placement focuses just on the best spots available and thus needs to install fewer turbines to obtain the same expansion in average power output terms. Moreover, Type-1 is the dominant turbine for the 5 GW expansion scenario. In particular, the best wind spots produce already quite high FLH making the smaller turbine more competitive. The bigger Type-2 in turn is build more intensely when the expansion target is higher and the algorithm starts to populate spots with lower wind speeds.

There are two main results of this descriptive analysis. First, Type-2 becomes dominant when

considering externalities because each turbine inflicts the same damages (see Table 2). Second, neglecting externalities when placing wind turbines fundamentally reduces the number of necessary turbines, but, in turn, might increase the externalities when calculating them back-of-the-envelope. We thus focus on the externalities arising from optimal and sub-optimal placement in the next subsection.

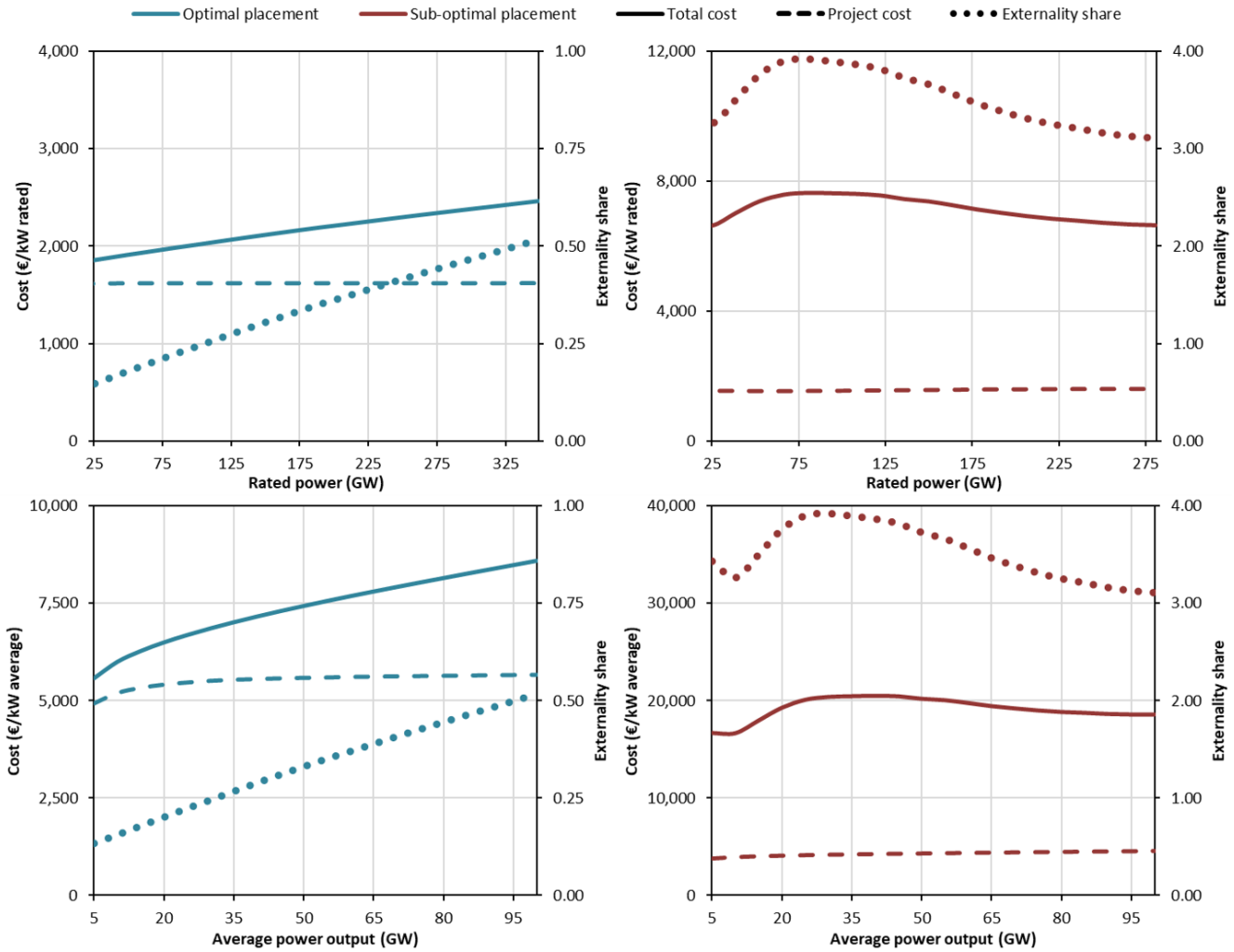
4.2. Cost and externality shares

We now calculate the externalities that would occur when placing turbines sub-optimally and add them to the project cost to obtain total cost. Figure 4 presents results of that task by showing total cost (solid lines), project cost (dashed lines, scales on the left axis), and the externality share as per cent of project cost (dotted lines, both scales on the right axis) when placing turbines optimal (blue) or sub-optimal (red). The upper panels plot cost and shares over rated power, the lower panels do so over average power output. Left panels show results for optimal placement (blue lines) and right panels show results for sub-optimal placement (red lines). Observe that the scales of the two right panels are four times the scale of the left panels. Note that average power output is a proxy for generation potential, that is, 100 GW average power output translates into a generation potential of 876 TWh (around 150% of 2020 German electricity consumption).

Project cost are comparable (almost constant) for optimal and sub-optimal placement when plotting those cost over rated power (upper panels). In particular, Type-2 turbines are slightly more expensive than Type-1 turbines (per kW rated power, see Table 1) and the share of Type-2 turbines for optimal placement is fundamentally higher (see Table 3). Consequently, the project cost for optimal placement are slightly above the one for sub-optimal placement (1,623 €/kW and 1,614 €/kW rated power for the 100 GW target). Project cost for optimal placement are higher when plotting over average power output (lower panels) because sub-optimal placement populates better spots in terms of wind speeds (5,671 €/kW vs. 4,529 €/kW average power output).

On the contrary, externality shares (in per cent of project cost) and also total cost are structurally higher for sub-optimal placement. Observe that the difference between total and project cost is the externality (in €/kW) that is inflicted by the placement. The average externality for the 100 GW expansion target is 2,930 €/kW (average power output) for optimal placement (reflecting an externality share of 52%) and 14,092 €/kW for sub-optimal placement (reflecting an externality share of 311%). Moreover, the externality share of sub-optimal placement is also not an increasing function but quite high already from the beginning. This result shows that the best wind spots in Germany inflict high externalities. We thus analyze the distribution of placed turbines and damage allocation across Germany in the next two subsections.

Figure 4: Total cost, project cost (both in €/kW), and externality shares for optimal (considering externalities) and sub-optimal (neglecting externalities) placement

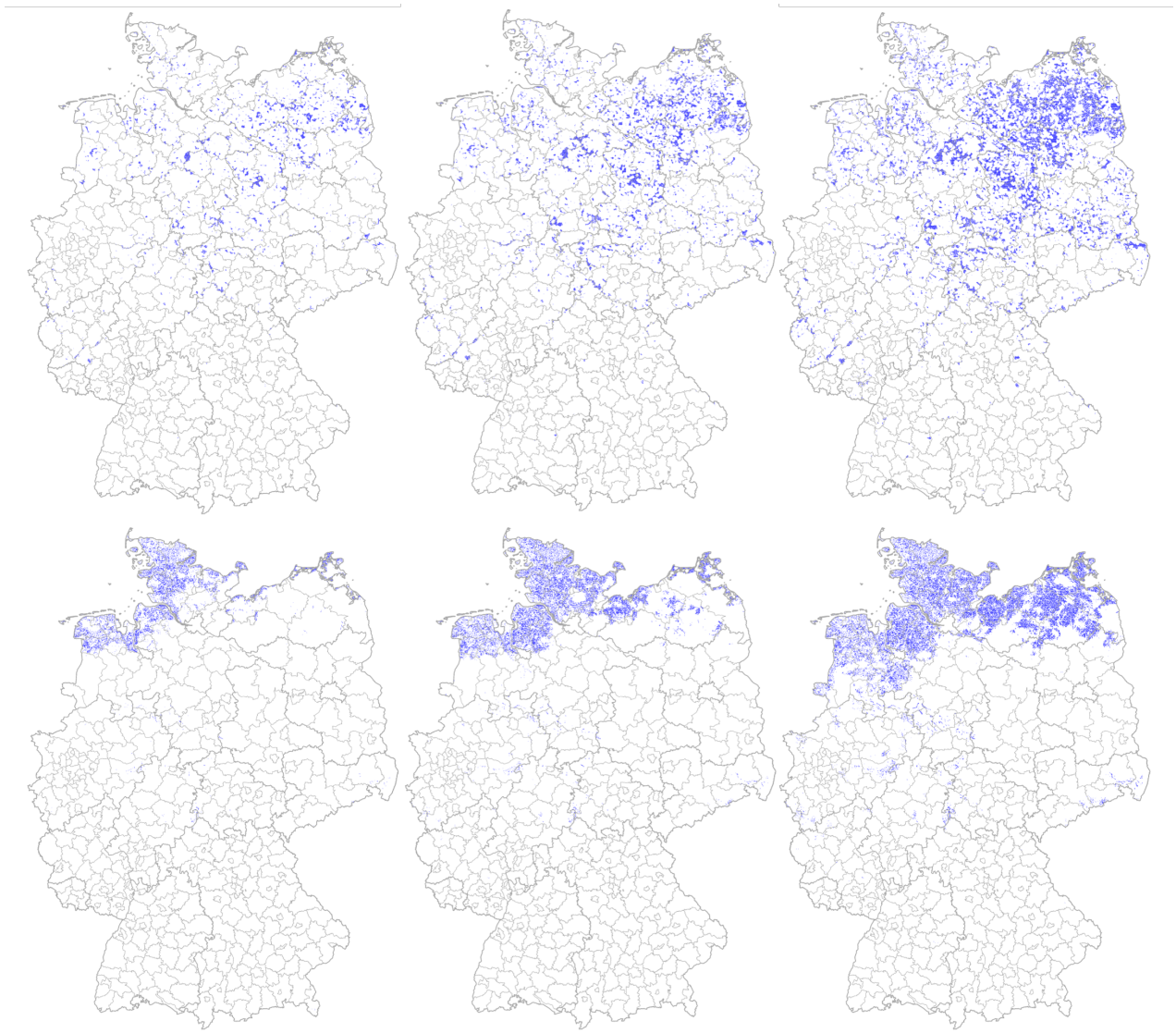


Bold lines show total cost, dashed lines show project cost (left axis, in €/kW), and dotted lines show externality shares (right axis, in per cent of project cost). Upper panels plot cost and shares over rated power (GW) and lower panels plot those over average power output (GW). Left panels show results for optimal placement (blue, rated power scale goes until 349 GW) and right panels show results for sub-optimal placement (red, scale goes until 281 GW).

4.3. Placement

Figure 5 shows placement of wind turbines for expansion targets of 25 GW (left panel), 50 GW (middle panel), and 100 GW (right panel) for optimal placement (upper panels) and sub-optimal placement (lower panels) of wind turbines. Note that optimal placement installs structurally more wind turbines (20,000 vs. 18,300 for 25 GW, 41,000 vs. 36,000 for 50 GW, and 83,200 vs. 68,100 for 100 GW) because optimal placement selects cells with lower average wind speeds due to noticeable higher externalities for the best spots.

Figure 5: Wind turbine placement for expansion targets of 25 GW (left), 50 GW (middle), and 100 GW (right) for optimal (upper maps) and sub-optimal (lower maps) placement



Start with optimal placement in the upper panels. Optimal placement of wind turbines leads to a disperse allocation of wind turbines in the Northern part of Germany with strong clusters in North-Eastern Germany under the 50 and 100 GW expansion targets. Southern Germany is very sparsely populated with only very few dots having medium to good wind speed levels (and small externalities). Now turn to sub-optimal placement in the lower panels. Observe that there is tremendous clustering of wind turbines in North-Western Germany (close to the Northern sea) where the best wind spots are located. The 25 GW target places almost no further turbines in North-Eastern Germany (only some spots very close to the Baltic sea). The 50 GW target expands

mainly in already populated areas but there are also few clusters in North-Eastern Germany. The 100 GW target finally also populates North-Eastern Germany quite densely. There are few rare spots in Central Germany that do not belong to the clustering process in Northern Germany. Observe that the clustering of turbines is far stronger than in the case of optimal placement. Indeed, the fact that each turbine in the proximity of a building adds to the damage burden of that property prevents a strong clustering under optimal placement.

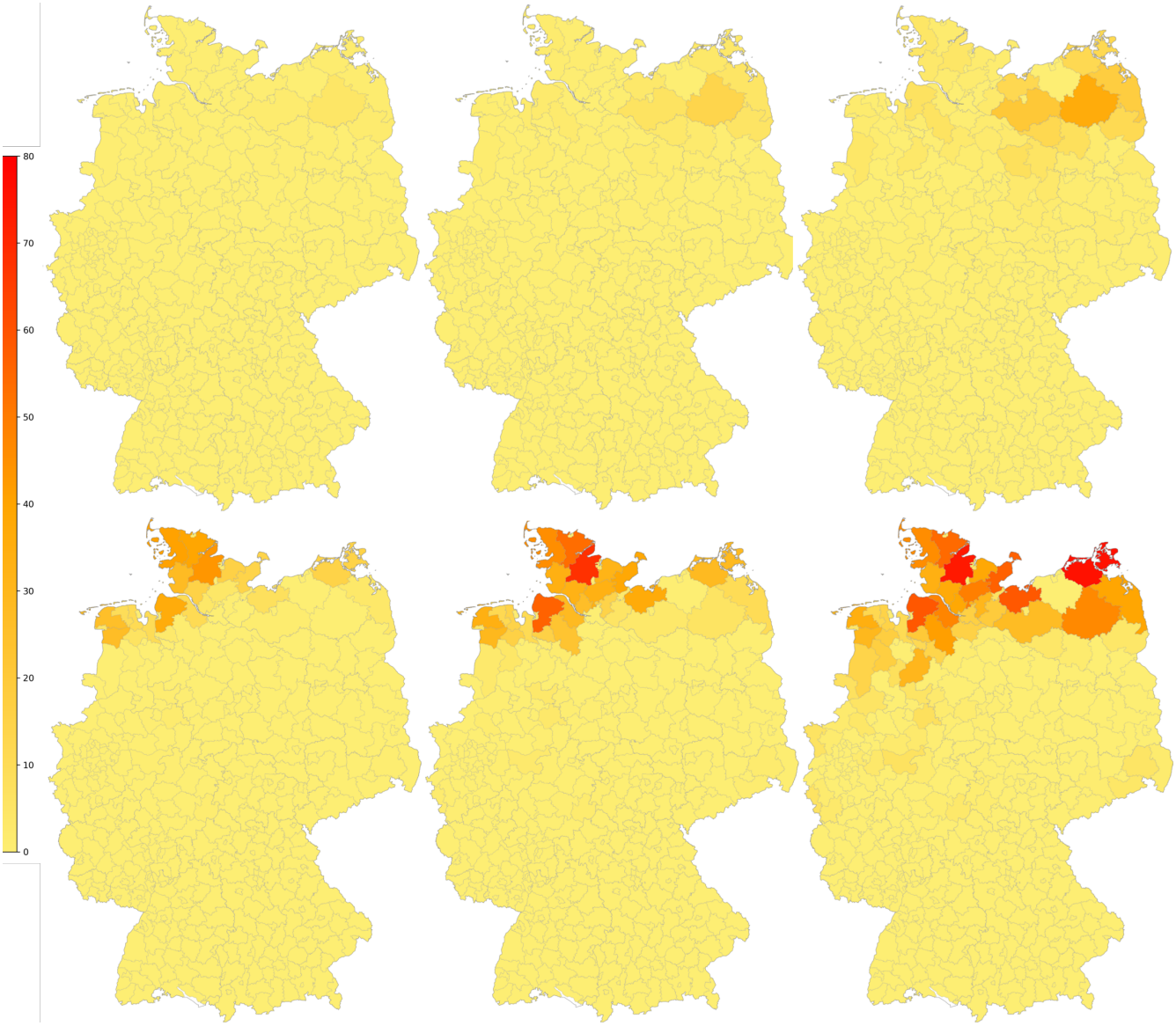
Remember from Figures 1 and 3 that the best wind spots are in Northern Germany while house prices are slightly higher in the very Northern parts of Germany compared to North-Eastern Germany. However, the price differences alone do not explain the disperse allocation of wind turbines when placing them optimally (compared to strong clustering close to the German shoreline when placing them without considering damages from noise and visibility). It is more the density of buildings that is decisive for this process. Observe from Figure 3 that population density is structurally lower in North-Eastern Germany, indicating that building density is also lower which results in more cells without high externality damages that are eligible for placement.

4.4. Distribution of damages

We now analyze the burden of wind turbine placement per county by analyzing absolute damages (in billion €) for each county. Figure 6 mirrors Figure 5 with the upper panels showing results for optimal placement and the lower ones for sub-optimal placement. The scale on the left shows damages in billion € per county. Observe that damages are strikingly lower in the optimal placement case. Indeed, total damages are 30 (92, 293) billion € for the 25 (50, 100) GW expansion target (in average power output terms). Conversely, damages are 400 (798, 1,409) billion € in the sub-optimal placement specification that neglects the existence of externalities when placing turbines. Optimal placement avoids damages in North-Western Germany but also along the North-Eastern shore line (proximity to Baltic sea). In turn, relevant damages occur only in North-Eastern Germany. Sub-optimal placement on the other hand produces tremendous damages along the shore lines. Interestingly, the entire process of turbine placement and consideration of externalities is only relevant in the very Northern part of Germany (best wind spots). The less windy and more expensive Southern part of Germany is negligible.

The damage distribution maps also provide the allocation of necessary compensation payments to internalize the damages. Compensation payments when placing turbines sub-optimally are mainly paid all over Northern Germany but, in particular, to property owners in areas close to the shore lines. Optimal placement moves turbines away from quite densely populated and high property price locations. In particular, optimal placement demands building more wind turbines away from the shore lines in North-Eastern Germany. In addition to that, compensation payments are highest for these areas, but structurally below the ones that would occur when placing turbines sub-optimal.

Figure 6: Externalities per county (in billion €) for expansion targets of 25 GW (left), 50 GW (middle), and 100 GW (right) for optimal (upper maps) and sub-optimal (lower maps) placement



5. Conclusion

We develop a wind turbine placement algorithm that places onshore wind turbines on a 500 × 500m grid under the consideration of minimum distances to obstacles (such as roads, buildings, and existing turbines), wind speeds, as well as distance-dependent noise and visibility damages in means of permanently devalued property prices. We apply our algorithm to the example region Germany, thereby combining Open Street Map (OSM, 2020), Global Wind Atlas (DTU, 2020), and data on

property prices (Kempermann et al., 2019) to resolve the trade-off between placing wind turbines in the best wind spots and externalities that arise from that placement. In particular, we run different expansion scenarios of average power output (5 to 100 GW) to reflect the wind quality under the objective of minimizing the sum of project cost (wind turbine, grid connection) and externalities (noise, visibility). We focus our analysis on the final placement decision (allocation of wind turbines in Germany) and the comparison of a specification that considers potential noise and visibility damages with one that neglects those. Furthermore, we calculate the damages that would occur when not considering those damages in the placement decision already.

Project cost across specifications and expansion scenarios are quite constant (around 1,600 €/kW rated power or 5,000 €/kW average power output), but the externality shares (in per cent of project cost) increase from 22% (for 25 GW average power output expansion, reflecting 84 GW rated power) to 52% (for 100 GW average power output, 349 GW rated power) when considering externalities during the placement process (final damages of 293 billion €). The latter share (damage) increases to 311% (1,400 billion €) when not accounting for potential noise and visibility damages during the placement process. Not considering externalities leads to clustering of wind turbines in Northern Germany along the shore lines of the Northern and Baltic sea, populating the very best wind spots (with average full-load hours above 3,100). Population densities and property prices are slightly higher in those areas than further inland in North-Eastern Germany, where a majority of wind turbines would be placed when considering externalities during the placement process (with average full-load hours above 2,500).

Policy makers should decide to start compensating local residents whose properties are affected by nearby wind turbines to increase local social acceptance of wind power. Assuming that Germany requires around 876 TWh additional wind power generation in 2045 (reflected by our 100 GW average power output expansion scenario) to contribute to European carbon neutrality targets, would lead to externalities of 1,400 billion € or around 60 billion €/year when not considering occurring noise and visibility damages in the placement decision already. The 60 billion €/year are around 16% of the 2020 German federal government budget. One could avoid the majority of cost when using slightly less windy spots in less populated regions or regions with comparatively lower property prices. Optimal placement requires more turbines but those would yield damages of only 293 billion €. Moreover, setting the correct incentives for firms by implementing transparent compensation schemes (firms compensate local population) on the basis of our algorithm would shift the externality burden to the firms running those wind turbines. Such externality internalizing placement would also resolve parts of local resistance. However, the compensation payment schemes must be transparent and easily applicable because it is not possible to bargain with local residents for years on each of the necessary 83,000 wind turbines.

Our analysis comes with come caveats. The first is the quantification of damages. Not all damage estimates from the literature are applicable to our problem because our algorithm needs distance-dependent damages to allow for a trade-off between placing wind turbines further away from buildings and using better wind spots. The damage estimates from Jensen et al. (2014) are at the upper end of literature values. Conversely, the sub-optimal placement specification that

neglects externalities should be considered as the lower boundary.[9] Second, we calculate damages for each wind turbine, that is, two wind turbines in the proximity of a property double the damage, although marginal damages intuitively decreases with the number of turbines. This assumption prevents strong clustering of wind turbines, which can be observed in the sub-optimal placement specification. Applying those decreasing marginal damages leads to slightly stronger clustering of turbines. The computational complexity of such a problem prevents running our algorithm for the entirety of Germany. However, such a decreasing marginal damage approach is useful for the detailed planning of single wind turbine placement and should be used as second layer of placement decisions. Third, we use average wind speeds to calculate the average power output of turbines. However, wind speeds vary over the year and thus cannot directly translated into full-load hours. We decide for a shortcut here and scale average power output of each spot so that the most windy spot in Germany delivers 4,000 full-load hours. We thus refrain from running complex algorithms to transform average wind speeds into timeseries to calculate exact full-load hours (e.g., Siala and Houmy, 2020). Finally, we allow to build only two different turbine types that reflect recent and current technological progress. Onshore wind deployment is a dynamic problem subject to increasing hub heights of turbines. Nevertheless, the two turbine types are quite close to each other so that damages are the same but average power output and cost differ. Adding additional types or substituting for one of the two would thus improve the dynamic depiction of wind turbine expansion scenarios. However, the calibration of damages for higher turbines comes at certain caveats again because all known damage estimates refer to existing turbines with hub heights as applied in our paper.

Constantly updating the quantification of damages in econometric case studies is necessary to depict dynamically changing preferences with regard to wind power noise and visibility. Implementing decreasing marginal damages, using a more detailed calculation of the average power output, and allowing to build higher turbines would be useful topics for future work. Moreover, the algorithm requires careful and recurring calibration (property prices, turbine types, damage estimates) when using it to calculate compensation payments for local residents in the proximity of potential wind turbine spots.

References

BKG (2020). Digitales Geländemodell Gitterweite 200m. Technical report, Bundesamt für Kartographie und Geodäsie. available online: https://gdz.bkg.bund.de/index.php/default/digitale-geodaten/digitale-gelandemodelle/digitales-gelandemodell-gitterweite-200-m-dgm200.html.

BNA (2020). Marktstammdatenregister. Technical report, Bundesnetzagentur. available online: https://www.
marktstammdatenregister.de/MaStR.

[9] Another quite applicable study is from Dröes and Koster (2016) who find substantially lower damages estimates. Implementing those damages yields an allocation of wind turbines that is a mix of our two main specifications with externalities shares of around 20% compared to 52% in our default calibration (for the highest expansion scenario).

Brennan, N. and T. M. Van Rensburg (2016). Wind farm externalities and public preferences for community consultation in Ireland: A discrete choice experiments approach. *Energy Policy 94*, 355–365.

DEPA (2011). Statutory Order on Noise from Wind Turbines. Technical report, Danish Environmental Protection Agency.

Dröes, M. I. and H. R. Koster (2016). Renewable energy and negative externalities: The effect of wind turbines on house prices. *Journal of Urban Economics 96*, 121–141.

DTU (2020). Global Wind Atlas 3.0. Technical report, Technical University of Denmark. available online: https://globalwindatlas.info/.

ENERCON (2015). Product overview. available online: https://www.enercon.de/fileadmin/Redakteur/Medien-Portal/broschueren/ pdf/en/ENERCON_Produkt_en_06_2015.pdf.

ENERCON (2019). Product overview. available online: https://www.enercon.de/fileadmin/Redakteur/Medien-Portal/broschueren/EC_Datenblaetter_WEA_de_082019.pdf.

Freiberg, A., C. Schefter, M. Girbig, V. C. Murta, and A. Seidler (2019). Health effects of wind turbines on humans in residential settings: Results of a scoping review. *Environmental Research 169*, 446–463.

Gibbons, S. (2015). Gone with the wind: Valuing the visual impacts of wind turbines through house prices. *Journal of Environmental Economics and Management 72*, 177–196.

Groothuis, P. A., J. D. Groothuis, and J. C. Whitehead (2008). Green vs. green: Measuring the compensation required to site electrical generation windmills in a viewshed. *Energy Policy 36*(4), 1545–1550.

Guttman, A. (1984). R-trees: A dynamic index structure for spatial searching. *Proceedings of the 1984 ACM SIGMOD International Conference on Management of Data*, 47–57.

Heintzelman, M. D. and C. M. Tuttle (2012). Values in the Wind: A Hedonic Analysis of Wind Power Facilities. *Land Economics 88*(3), 571–588.

Hoen, B., J. P. Brown, T. Jackson, M. A. Thayer, R. Wiser, and P. Cappers (2015). Spatial Hedonic Analysis of the Effects of US Wind Energy Facilities on Surrounding Property Values. *The Journal of Real Estate Finance and Economics 51*(1), 22–51.

Ituarte-Villarreal, C. M. and J. F. Espiritu (2011). Optimization of wind turbine placement using a viral based optimization algorithm. *Procedia Computer Science 6*, 469–474.

Jensen, C. U., T. E. Panduro, and T. H. Lundhede (2014). The Vindication of Don Quixote: The Impact of Noise and Visual Pollution from Wind Turbines. *Land Economics 90*(4), 668–682.

Kempermann, H., A. Ricci, P. Sagner, and T. Lang (2019). Sparda-Studie Wohnen in Deutschland 2019. Technical report, Institut der Deutschen Wirtschaft on behalf of the Verband der Sparda-Banken e.V. available online: https://www.sparda-wohnen2019.de/.

Klæboe, R. and H. Sundfør (2016). Windmill noise annoyance, visual aesthetics, and attitudes towards renewable energy sources. *International Journal of Environmental Research and Public Health 13*(8), 746.

Knopper, L. D. and C. A. Ollson (2011). Health effects and wind turbines: A review of the literature. *Environmental Health 10*(1), 78.

Lütkehus, I., K. Adlunger, and H. Salecker (2013). Potenzial der Windenergie an Land: Studie zur Ermittlung des bundesweiten Flächen-und Leistungspotenzials der Windenergienutzung an Land. Technical report, Umweltbundesamt.

Meyerhoff, J., C. Ohl, and V. Hartje (2010). Landscape externalities from onshore wind power. *Energy Policy 38*(1), 82–92.

Mier, M., J. Adelowo, and C. Weissbart (2021). Taxation of carbon emissions and air pollution in intertemporal optimization frameworks with social and private discount rates. *ifo Working Paper No. 360*.

OSM (2020). Open Street Map shapefile for Germany. Technical report, OpenStreetMap Foundation. available online: https://www.openstreetmap.org, retrived from: https://www.geofabrik.de/.

Rodman, L. C. and R. K. Meentemeyer (2006). A geographic analysis of wind turbine placement in northern california. *Energy Policy 34*(15), 2137–2149.

Siala, K. and H. Houmy (2020). tum-ens/pyGRETA: python Generator of REnewable Time series and mAps. *Software Repository*.

Vyn, R. J. and R. M. McCullough (2014). The effects of wind turbines on property values in Ontario: Does public perception match empirical evidence? *Canadian Journal of Agricultural Economics 62*(3), 365–392.

Wallasch, A.-K., S. Lüers, and K. Rehfeldt (2015). Kostensituation der Windenergie an Land in Deutschland—Update. Technical report, Deutsche WindGuard.

WHO (2018). Environmental noise guidelines for the European region. Technical report, World Health Organization. Publisher: World Health Organization. Regional Office for Europe.

Zergane, S., A. Smaili, and C. Masson (2018). Optimization of wind turbine placement in a wind farm using a new pseudo-random number generation method. *Renewable Energy 125*, 166–171.