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Where do all the windmills go? Influence of the institutional setting on the spatial distribution of renewable energy installation

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A B S T R A C T

Promoting renewable energy sources is one policy response to climate change. Not only is there currently a debate over the best policy instrument, it is also discussed whether the renewable energy production should be expanded centralized at locations with the highest production potential or decentralized close to load. It is yet not fully understood what influences the spatial distribution of renewable energy installation.

I assess the effect of subsidy scheme and market design on the spatial distribution of wind energy installations by comparing (a) feed-in tariffs versus market premiums and (b) uniform versus nodal pricing. The analysis is based on theoretical considerations and using a six-node test model that reflects the consumption and renewable resource distribution in several countries and regions.

The institutional setting has great influence on the spatial distribution and resulting system costs. With uniform pricing, a market premium only leads to a more decentralized expansion of renewable energy production than a tariff when sites share similar wind conditions. Spatially more distributed expansion of wind power performs better in terms of total costs and share of wind power in final demand when networks are restricted.

1. Introduction

Most countries worldwide have by now set targets for the percentage of electricity generated from renewable sources, for example, Australia 20%, Denmark 50%, and France 27% by 2020 (REN21, 2014). There is an ongoing political and scientific debate on how these targets can be achieved and specifically on the best policy instruments for doing so (Butler and Neuhoff, 2008; Dong, 2012). It is also being discussed whether renewable energy production facilities should be grouped at centralized locations with the best production potential but often far from load, or whether they should be distributed in a decentralized fashion close to load (Breyer et al., 2013; Agora Energiewende, 2013; Schmid et al., 2016). This becomes particularly important when network capacities are restricted and extension is hampered.

Related to this is the question of how each of these patterns can be fostered. Besides physical conditions, several aspects may influence the spatial distribution of renewable energy generation: support schemes, market design, and grid integration (see Hiroux and Saguan, 2010). How these parameters influence the spatial distribution of renewable energies is not yet fully understood.

While a range of studies have analyzed the optimal expansion of renewable energies from a welfare perspective (e.g. Dietrich et al., 2010; Schmid et al., 2013; Hirth, 2015), few deal with the impact of different institutional settings on the spatial decisions of investors and on total costs when network expansion is restricted. If renewable producers do not receive regional signals other than production potential, they will not take into account the externalities of renewable feed-in on the network, such as the exacerbation or alleviation of line congestion. Furthermore, the price-reducing effect of renewable power production, referred to as the merit order effect (Sensfuß et al., 2008; Cludius et al., 2014), is only transmitted to renewable power producers, if their revenue is price-dependent. Grimm et al. (2016) analyze the effect of different market designs and network management on the investment decisions of conventional power generators. Hiroux and Saguan (2010) give an overview of how support schemes for renewable energy supply (RES) and network integration designs interact in creating regional incentives. Elberg and Hagspiel (2015) show that the market value of wind power plants is spatially dependent. Goetzke and Rave (2016) analyze the influence of socio-economic factors on wind power distribution in Germany.

To the author's knowledge, so far only Hitaj et al. (2014), Grothe and Müsgens (2013) and Schmidt et al. (2013) have examined the effect of different renewable subsidy schemes on the spatial

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distribution of wind power. The first compare econometrically for Germany uniform feed-in tariffs with tariffs depending on wind power potential and find an effect on the spatial distribution. The second quantify differences in revenue under the feed-in tariff and the sliding[1] market premium system in Germany for different locations. The third analyze with a simulation model of the effect of feed-in tariff and market premium in Austria. Yet all three studies do not consider the effect of different market designs and do not take network restrictions into account. They also only partly decompose the influence of institutional and other environmental parameters.

The contributions of this paper to the literature are additional insights into the drivers of spatial distribution of wind power capacity. This is achieved not only by applying a greater variation of institutional settings than before, but also by decomposing wind resource into output, variance and correlation. Moreover, the effects of different spatial distributions on total costs and the share of wind power in final demand are analyzed.

The focus is on three specific institutional settings: (1) feed-in tariff in a uniform pricing regime, (2) market premium in a uniform pricing regime and (3) market premium in a nodal pricing regime. Both tariff and market premium are fixed.[2] The analysis is conducted based on theoretical considerations and using a simplified six-node test model that has been widely applied in the literature to illustrate effects of market design and investment incentives (e.g. Oggioni and Smeers, 2013; Ehrenmann and Smeers, 2005; Grimm et al., 2016). The model cannot give detailed answers or predictions for a certain country or region. However, it allows analyzing more generally the case where the best physical conditions for renewable production are distant from demand centers and transfer capacity is restricted. This reflects not only to the situation in single countries, but also e.g. in Europe and the United States in general (Velte et al., 2013; Schaber et al., 2012; Imperial College et al., 2014; Lamy et al., 2016; Mai et al., 2012; Wright, 2012; Kerr, 2014).

The model enables illustrating the effect of different regimes on spatial distribution, as well as deriving policy recommendations. Apart from the Chao–Peck model, a variety of capacity expansion models exists that use similar forms of optimization, such as TIMES, NEMS, ELMOD and ReEDS (Loulou et al., 2005; EIA, 2015; Leuthold et al., 2012; NREL, 2015). To the author's knowledge these have, however, not been applied for this purpose.

I find that wind power output dominates the spatial distribution in all three institutional settings. Under a market premium, variance in wind power output and the correlation of wind power output with demand and with wind power output at other sites also influence the decision, especially if wind conditions do not differ significantly between locations. Only when locations share similar conditions do these additional effects lead to a spatially more distributed expansion of renewable energy under a market premium than a feed-in tariff. The analysis further shows that spatially more distributed expansions of wind power plants outperform centralized ones when network capacities are restricted in terms of total costs per MWh and share of wind power in final demand.

In the following, first, the analytical model is introduced and an overview of factors influencing spatial distribution is given. Second, the test model is described with all modifications made and, third, the results are presented. Finally, the results are discussed and conclusions drawn.

[1] In practice fixed and sliding alternatives exist in particular for market premiums. While the premium level is constant in the first case, it depends e.g. on average market prices and/or the market value of wind power, and is often calculated on a monthly basis in the second case (for a detailed overview see RES LEGAL Europe, 2016).

[2] A fixed premium is implemented for instance in Denmark. Also Schmidt et al. (2013) model a fixed market premium for Austria.

2. Model formulation

To analyze the effect of subsidy scheme and electricity market design on spatial wind power investment decision, I distinguish three different institutional settings:

1. Wind power feed-in is remunerated with a tariff with uniform pricing (*T-UP*).
2. Remuneration is based on a market premium with uniform pricing (*P-UP*).
3. The market premium is granted in an energy market with nodal pricing (*P-NP*).

Uniform pricing (UP) is predominant in most European countries. In such a setting, electricity is traded without regard to physical network constraints, which are thus not reflected in the market price.[3] After the market is cleared, a transmission system operator (TSO) analyzes whether the market solution is technically feasible. Only if unfeasible, generation and consumption are redispatched. I assume a cost-based redispatch, which minimizes additional generation costs.

Under nodal pricing (NP), in contrast, the energy and transmission functions are fully integrated (Oggioni and Smeers, 2013; Chao and Peck, 1998). In the case of line congestion, the nodal electricity prices reflect the congestion costs in addition to the marginal production costs at the node. NP is applied, for instance, in US and New Zealand markets. In this paper it is used as a first best benchmark. In the following, more details are given on the model set-up. A full overview of all model sets, indices, parameters and variables is given in Table 1.

I consider an electricity network with $N = \{n_1, ..., n_{|N|}\}$ nodes and $L = \{l_1, ..., l_{|L|}\}$ transmission lines in a set of periods $T = \{t_1, ..., t_{|T|}\}$. A loss-less direct current (DC) power flow approximation of the real power flows is applied in this paper based on Schweppe et al. (1988), which integrates Kirchhoff's current and voltage law. A DC-load flow model is a good approximation of a real world alternating current (AC) network in the case of stable conditions, i.e. particularly in the case of only small differences of constant phase-angles at each node (Stigler and Todem, 2005). At each individual node $n \in N$ and in each time period $t \in T$, electricity is demanded ($d_{n,t}$) and/or produced from conventional energy sources ($g_{n,t}$). I assume a concave utility function, $B(d_{n,t})$, ($B' > 0$ and $B'' < 0$) and price-elastic demand, $d_{n,t}(p_t)$, with $d' < 0$. The generation cost function $G(g_{n,t})$ of conventional power production is assumed to be convex ($G' > 0$ and $G'' > 0$). In addition, each node has a distinct wind supply ($v_{n,t}$) and hence a specific wind power output ($w_{n,t}$) per installed wind turbine.

Different levels of decision-making are modeled reflecting a sequential order. On the first level, the investment decision is made by the wind power investor about how much wind power capacity to install at each node ($C_n \geq 0$). On the second level, all power is traded in a set of periods.[4] In a uniform pricing system, a third level with redispatch is included. For reasons of clarity the different levels are described separately in the following. The decisions are, however, not completely independent from one another. Except for the fixed feed-in setting, the investment decision on the first level anticipates the outcomes of the second level, which in turn depends on the first level decision. Since remunerations for wind power plant operators as well as for conventional producers do not change with the redispatch, the result of this third level is not anticipated on the previous levels.

[3] I also assume that only energy units (MWh) and not capacity (MW) is remunerated within such markets.

[4] I assume that the wind power plant operator sells all power produced on the market and does not use it for own consumption.