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An Illustrative Note on the System Price Effect of Wind and Solar Power: The German Case

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Abstract Exposing wind and solar power to the market price signal allows for cost-efficient investment decisions, as it incentivizes investors to account for the marginal value (MV^{el}) of renewable energy technologies. As shown by Lamont (2008), the MV^{el} of wind and solar power units depends on their penetration level. More specifically, the MV^{el} of wind and solar power units is a function of the respective unit's capacity factor and the covariance between its generation profile and the system marginal costs. The latter component of the MV^{el} (i.e., the covariance) is found to decline as the wind and solar power penetration increases, displacing dispatchable power plants with higher short-run marginal costs of power production and thus reducing the system marginal costs in all generation hours. This so called 'system price effect' is analyzed in more detail in this paper. The analysis complements the work of Lamont (2008) in two regards. First of all, an alternative expression for the MV^{el} of wind and solar power units is derived, which shows that the MV^{el} of fluctuating renewable energy technologies depends not only on their own penetration level but also on a variety of other parameters that are specific to the electricity system. Second, based on historical wholesale prices and wind and solar power generation data for Germany, a numerical 'ceteris paribus' example for Germany is presented which illustrates that the system price effect is already highly relevant for both wind and solar power generation in Germany.

Keywords Fluctuating generation technologies · Wind power · Solar power · System price effect

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Analyse des Systempreiseffektes von Wind- und Solarkraft in Deutschland

Zusammenfassung Nur wenn Investoren das Marktpreissignal und damit den Grenzwert (MW_{el}) fluktuierender erneuerbarer Energien in ihr Investitionskalkül miteinbeziehen, werden kosteneffiziente Investitionsentscheidungen getroffen. Wie von Lamont (2008) gezeigt, hängt der MW_{el} der Wind- und Solarkraft von ihrer Durchdringungsrate ab. Im Speziellen gilt, dass der MW_{el} der Wind- und Solarkraft eine Funktion des technologiespezifischen Kapazitätsfaktors und der Kovarianz zwischen dem technologiespezifischen Erzeugungsprofil und den Systemgrenzkosten ist. Letztere sinken mit steigender Durchdringung der Wind- und Solarkraft, da steuerbare Kraftwerke mit höheren kurzfristigen Grenzkosten verdrängt werden und damit die Systemgrenzkosten in allen Stunden mit Wind- und Solarerzeugung sinken. Dieser Systempreiseffekt ist Untersuchungsgegenstand des vorliegenden Artikels, der die Arbeit von Lamont (2008) in zweierlei Hinsicht ergänzt: Zum einen wird eine alternative Definition des MW_{el} von Wind- und Solarkraft hergeleitet, mit der gezeigt werden kann, dass der MW_{el} von fluktuierenden erneuerbaren Energien nicht nur vom eigenen Durchdringungsgrad, sondern von einer Vielzahl weiterer Parameter abhängig ist, die spezifisch für das jeweilige Stromsystem sind. Zum anderen wird basierend auf historischen Strompreis- und Wind- /Solarerzeugungsdaten illustriert, dass der Systempreiseffekt sowohl für Wind als auch für Solarkraft bereits heute von erheblicher Relevanz in Deutschland ist.

1 Introduction

The competitiveness of wind and solar power technologies is often evaluated in public debates by comparing levelized costs of electricity (LCOE). However, as argued by Joskow (2013), comparing the economic attractiveness of fluctuating wind and solar power units to that of conventional dispatchable generation capacities based on the LCOE is flawed since it fails to account for the fact that the value of electricity supplied (i.e., the wholesale market price) varies over the course of the day and the year. Similarly, renewable energy support schemes are often designed to incentivize investors to only account for the marginal costs (MC) but not for the marginal value (MV^{el}) of renewable energy technologies, i.e., the revenue from selling electricity on the wholesale market during their technical lifetime.

Whereas it is commonly recognized that dispatchable renewable energy technologies such as biomass power plants should be exposed to the price signal of the wholesale market, exposing fluctuating wind and solar power technologies to the market price signal is often argued to have no merit (e.g., Klessmann et al. (2011)). This statement is partly true from a short-term perspective since wind and solar power have no short-run marginal costs of power production, which incentivizes wind and solar power generators to produce electricity whenever the wind is blowing or the sun is shining – irrespective of the current market price signal (Hiroux and Saguan (2011)). On the other hand, exposing fluctuating renewables to the market price signal at least induces wind and solar power generators to voluntarily curtail their power generation in response to negative prices (e.g., Hiroux and Saguan (2011), Klessmann et al. (2011)) and to align their maintenance planning to hours in which their power generation is less valuable for the system (e.g., Gawel and Purkus (2011), Hiroux and Saguan (2011)). Most importantly, however, exposing wind and solar power to the market price signal allows for cost-efficient investment decisions, as it incentivices investors to account for the marginal value (MV^{el}) of renewable energy technologies (see also Jägemann (2014)).

As shown by Lamont (2010), the MV^{el} of wind and solar power units depends on their penetration level. More specifically, the MV^{el} of wind and solar power units is a function of the respective unit's capacity factor and the covariance between its generation profile and the system marginal costs. The latter component of the MV^{el} (i.e., the covariance) declines as the wind and solar power penetration increases, displacing dispatchable power plants with higher short-run marginal costs of power production and thus reducing the system marginal costs in all generation hours. This so called 'system price effect' is analyzed in more detail in this paper.[1]

Our analysis complements the work Lamont (2010) in two regards. First of all, we derive an alternative expression for the MV^{el} of wind and solar power units, which shows that the MV^{el} of wind (solar) power technologies depends not only on their own penetration level but also on a variety of other parameters that are specific to the electricity system. Second, based on historical wholesale prices and wind and solar power generation data for Germany, we present a numerical 'ceteris paribus' example for Germany which illustrates the decrease in the MV^{el} of wind and solar power units as penetration increases (as a consequence of the system price effect).

The structure of the paper is as follows: Sect. 2 discusses the marginal value (MV^{el}) of wind and solar power from a theoretical perspective, before Sect. 3 numerically illustrates the system price effect of wind and solar power in Germany. Section 4 draws conclusions.

2 Theoretical Analysis

In the following we first derive the characteristics of a cost-efficient renewable energy mix (Sect. 2.1), before we analyze the determinants of the marginal value (MV^{el}) of wind and solar power in more detail (Sect. 2.2).

2.1 What Characterizes a Cost-Efficient Renewable Energy Mix?

The analysis complements the work of Lamont (2010) in accounting for politically implemented renewable energy (RES-E) targets. Just as in Lamont (2010), the optimality condition for renewable energy expansions is analyzed for the example of fluctuating wind and solar power units. The focus on wind and solar power is motivated by the fact that they differ from conventional dispatchable power plants in the sense that their power production is weather dependent (i.e., it depends on the availability of wind and solar power resources, which differs between regions) and that they are associated with (almost) no short-run marginal costs of power production. Moreover, given limited potentials for hydro power and low-cost biomass resources in generating electricity, wind and solar power are expected to account for the largest share of renewable energy capacity additions in the coming years.

[1] In contrast to Lamont (2010), Hirth (2010) and Nicolosi (2010) analyze the annual 'value factor' of wind and solar power in Northwestern Europe and Germany, respectively, which can be understood as a proxy/indicator for the MV^{el} of wind and solar power, as it is defined as the average hourly revenue of wind and solar power generators relative to the time-weighted average wholesale price (base-price) per year. Both papers apply a linear dispatch and investment model and find that the annual value factor of wind and solar power decreases with increasing penetration of these technologies.

The optimality condition for the expansion of fluctuating wind and solar power units (C^f) with an hourly power output of $pf_{y,h}^{f}$ under a technology- and region-neutral RES-E target can be derived by minimizing total system costs (as demonstrated in Appendix A.1, see Eq. (20–28)).[2]

In the optimum, fluctuating renewable energy units (C^f) are expanded up to the point at which their marginal costs (MC) correspond to the sum of their marginal value of power supply (MV^{el}) and their marginal value of renewable energy supply (MV^{ren}), given a technology- and region-neutral RES-E target (see Eq. 1).[3]

This reflects a basic economic principle under perfect competition: Marginal profits are zero for the capacity level at which marginal costs equal marginal value, which implies that profits are maximized or (alternatively) costs are minimized.

In general, the competitive equilibrium is characterized by a market clearance and a zero profit condition. Market clearance refers to the condition that (i) a wholesale price for electricity ($\mu_{y,h}$) is established through competition such that the amount of electricity demanded is equal to the amount of electricity produced, and (ii) that a market price for 'green electricity' (green certificates) (ρ_y) is established such that the amount of 'green electricity' demanded (by the RES-E target) is equal to the amount of 'green electricity' produced. Moreover, in line with the zero profit condition, investments in fluctuating renewable energy capacities (C^f) take place as long as investments break even, i.e., up until the point the sum of their marginal value of power supply (MV^{el}) and their marginal value of renewable energy supply (MV^{ren}) corresponds to the unit's marginal costs (MC). This corresponds to the result of Lamont (2010) who showed that the costs of an additional unit of wind and solar power capacity should be equal to the benefits that it provides to the system. However, in contrast to our analysis, Lamont (2010) only accounted for the benefits of meeting electricity demand (MV^{el}) but not for the benefit of meeting renewable energy targets, i.e., the benefit of supplying 'green electricity' (MV^{ren}).

$$\underbrace{\sum_{y\in Y} fc_y^f}_{MC_{cf}} \overset{!}{=} \underbrace{\sum_{y\in Y}\sum_{h\in H} pf_{y,h}^{f}\cdot \mu_{y,h}}_{MV_{cf}^{el}} + \underbrace{\sum_{y\in Y}\sum_{h\in H} pf_{y,h}^{f}\cdot \rho_y}_{MV_{cf}^{ren}} \quad (1)$$

While the MC are defined as the unit's accumulated annualized investment costs (fc_y^f) over all years (Y) of its technical lifetime, the MV^{el} of wind and solar power units corresponds to the accumulated revenue from selling electricity ($pf_{y,h}^{f}$) at the wholesale market at price $\mu_{y,h}$ in all hours (H) and years (Y) of the unit's technical lifetime. Assuming perfect competition and a price-inelastic electricity demand, the shadow variable of the power balance constraint (see Eq. 23 and 26 of the Appendix) – which represents the system's marginal costs associated with meeting the hourly electricity demand at a specific point in time – serves as proxy for the wholesale price ($\mu_{y,h}$). Hence, the MV^{el} of wind and solar power units reflects the accumulated value of the good 'electricity' (wholesale price) supplied by wind and solar power units during their technical lifetime.

In contrast to the MV^{el}, the MV^{ren} of wind and solar power units represents the accumulated value of the good 'green electricity' supplied by wind and solar power units during their technical lifetime under politically implemented RES-E targets. RES-E targets can hardly be justified from a climate protection perspective, given the implementation of a CO_2 emission cap which limits the overall CO_2 emissions (see, e.g., Jägemann et al. (2013)). However, if renewable energy targets are nevertheless implemented, they may reflect the society's preference for electricity generation from renewable energy sources over electricity generation from non-renewable sources (i.e., fossil fuels or nuclear power). As such, electricity produced from wind and solar power units may have an additional value for the society (compared to electricity produced from non-renewable sources), which is derived from its property of being 'green'. Just as in the case of the good 'electricity', which is traded and priced on the wholesale electricity market, the good 'green electricity' can be traded and priced on a market for 'green electricity'. Such markets exist, for example, in countries where governments have implemented renewable energy quota obligations in combination with tradable green certificates (TGC) which generators receive from the government for each kWh of 'green electricity' produced.[4] In this case, the MV^{ren} of

[2]Due to the assumption of perfect competition and a price-inelastic electricity demand the cost-minimization approach corresponds to a welfare-maximization approach. Alternatively, the optimality condition for the expansion of fluctuating wind and solar power units could be derived by maximizing profits (assuming perfect competition and a price-inelastic electricity demand).

[3]The term 'technology- and region-neutral' indicates that each kWh of renewable electricity produced contributes to achieving the RES-E target irrespective of the technology or the region of its deployment.

[4]Quota obligations in combination with tradable green certificates (TGC) fix the quantity of renewable electricity to be generated. The supply of TGC is ensured by giving producers a certificate for each unit of renewable energy sold. The demand for TGC is induced by transferring the politically implemented RES-E target to distribution companies (electricity suppliers), who are then required to prove that a certain proportion (quota) of the electricity supplied to their final consumers was generated from renewable energy sources.

wind and solar power units corresponds to the accumulated revenue from selling TGC on the green certificate market. The price of TGC is given by ρ_y, which corresponds to the shadow variable of the renewable energy constraint (see Eq. (25) and (26) of the Appendix) and indicates the marginal system costs associated with the achievement of the politically implemented RES-E target. Overall, the MV^{ren} of wind and solar power units represent the part of the MC that cannot be covered by the revenue from selling electricity on the wholesale market during the unit's technical lifetime (i.e., the MV^{el}), as shown by Eq. (2).

$$MV_{C^f}^{ren} = MC_{C^f} - MV_{C^f}^{el} \tag{2}$$

Summarizing, while the MC reflect the unit's capital costs, the MV^{el} of wind and solar power units is defined as the accumulated revenue from selling electricity on the wholesale market during the unit's technical lifetime. Hence, in contrast to the MC, the MV^{el} of wind and solar power units depends on a variety of parameters that are specific to the electricity system. In the next section we analyze the determinants of the MV^{el} of wind and solar power units to gain a better understanding of what drives the MV^{ren} of renewable energy technologies, i.e., the part of the MC that needs to be covered by renewable energy support payments to incentivice investments.

2.2 What Determines the Marginal Value of Power Supply (MV^{el})?

In the following two alternative theoretical definitions of the marginal value of wind and solar power units (MV^{el}) are derived.

2.2.1 *Definition 1*

The marginal value of power supply (MV^{el}) is defined as the accumulated revenue from selling electricity on the wholesale market at price $\mu_{y,h}$ in all hours (H) and years (Y) of the unit's technical lifetime (Eq. (3)).

$$MV_{C^f}^{el} = \sum_{y \in Y} \sum_{h \in H} pf_{y,h}^f \cdot \mu_{y,h} \tag{3}$$

Let us assume that the hourly power output of wind or solar power units ($G_{y,h}^f$) is given by the production factor (pf_h^f) in the equilibrium (Eq. (4)), which implies that no curtailment of wind and solar power generation takes place.

$$G_{y,h}^f = pf_{y,h}^f \cdot C^f \tag{4}$$

Hence, the equilibrium output of dispatchable generators $\left(\sum_{d \in D} G_{y,h}^d\right)$, which corresponds to the residual load ($RL_{y,h}$), is given by Eq. (5).

$$\sum_{d \in D} G_{y,h}^d = l_{h,y} - \sum_{f \in F} pf_{y,h}^f \cdot C^f = RL_{y,h} \tag{5}$$

In our modeling framework, dispatchable generators offer their output at a price equal to their short-run marginal costs of power production, which are assumed to be a linear function of the total dispatchable power output ($\sum_{d \in D} G_{y,h}^d$), see Eq. (6).[5] The function represents a merit-order curve of dispatchable power plants with different short-run marginal costs of power production.[6]

$$\frac{dVC^d}{d\sum_{d \in D} G_{y,h}^d} = a + b \cdot \sum_{d \in D} G_{y,h}^d \tag{6}$$

The parameter a reflects the short-run marginal costs of power production from the dispatchable power plant with the lowest short-run marginal production costs. Moreover, given the linear approximation of the (staircase-shaped) merit-order curve, b reflects the difference in the short-run marginal production costs between the dispatchable power plant with the lowest and the highest short-run marginal production costs. Hence, the larger the difference between the short-run marginal production costs between the dispatchable power plants is, the higher the slope of the linear (approximated) merit-order curve becomes.

Since the short-run marginal costs of wind and solar power production are zero, the wholesale price ($\mu_{y,h}$) is assumed to always be set by a dispatchable generator.

$$\mu_{y,h} = a + b \cdot \sum_{d \in D} G_{y,h}^d \tag{7}$$

Thus, the equilibrium wholesale price ($\mu_{y,h}$) is given by Eq. (8).

$$\mu_{y,h} = a + b \cdot (l_{h,y} - \sum_{f \in F} pf_{y,h}^f \cdot C^f) = a + b \cdot RL_{y,h} \tag{8}$$

Equation (9) (i.e., the derivative of the wholesale price function with respect to C^f) illustrates the short-term merit-order effect: The wholesale price decreases as (ceteris paribus) the

[5]The assumption that dispatchable generators offer their output at a price equal to their short-run marginal costs of power production reflects the assumption of perfect competition.

[6]The assumption of a linear function is in line with Bode (2006). However, in reality, the shape of the merit-order curve is rather staircase-shaped. More specifically, with every generator bidding its total capacity at a price equal to its short-run marginal costs of power production, the aggregate supply is a staircase function.

penetration of fluctuating wind and solar power capacities (C^f) with no short-run marginal costs of power production increases.[7]

$$\frac{d\mu_{y,h}}{dC^f} \leq 0 \tag{9}$$

Inserting Eq. (8) in Eq. (3) shows that the marginal value (MV^{el}) of fluctuating renewables (C^f) can generally be expressed as follows:

$$MV^{el}_{C^f} = \sum_{y\in Y}\sum_{h\in H}(pf^f_{y,h}\cdot\mu_{y,h}) = \sum_{y\in Y}\sum_{h\in H}(pf^f_{y,h} \cdot (a + b\cdot(l_{h,y} - \sum_{f\in F} pf^f_{y,h}\cdot C^f))). \tag{10}$$

The MV^{el} of wind (C^w) and solar (C^s) power capacities is given by Eqs. (11) and (12), respectively.

$$MV^{el}_{C^w} = \sum_{y\in Y}\sum_{h\in H}(pf^w_{y,h}\cdot(a + b\cdot(l_{h,y} - pf^w_{y,h} \cdot C^w - pf^s_{y,h}\cdot C^s))) \tag{11}$$

$$MV^{el}_{C^s} = \sum_{y\in Y}\sum_{h\in H}(pf^s_{y,h}\cdot(a + b\cdot(l_{h,y} - pf^s_{y,h} \cdot C^s - pf^w_{y,h}\cdot C^w))) \tag{12}$$

Equations (11) and (12) demonstrate that the MV^{el} of wind power and solar power units is a function of the penetration of wind and solar power capacities (i.e., the level of C^w and C^s), the wind and solar power production factor profiles ($pf^w_{y,h}$ and $pf^s_{y,h}$) and the load profile ($l_{y,h}$). Moreover, the MV^{el} depends on the shape of the wholsale price function (Eq. (8)), based on the level of a (intersection) and b (slope).[8]

Due to the short-term merit-order effect, the MV^{el} of wind power (ceteris paribus) decreases not only as wind power penetration increases but also as solar power penetration increases (and vice versa) (see Eq. (13–14)). Equally, the MV^{el} of wind and solar power (ceteris paribus) decreases as the hourly load ($l_{y,h}$) decreases. This result reflects a basic economic interdependence: Assets (i.e., in this case 'electricity') decrease in value as their scarcity decreases, i.e., if supply increases or demand decreases. Thus, an asset essentially has no value if it abundant.

Moreover, the MV^{el} of wind and solar power (ceteris paribus) increases as the slope (b) of the wholesale price function (i.e., the merit-order curve) increases, meaning that the difference in the short-run marginal production costs between the single dispatchable power plant capacities increases.

$$\frac{\delta MV^{el}_{C^w}}{\delta C^w} \leq 0;\ \frac{\delta MV^{el}_{C^w}}{\delta C^s} \leq 0;\ \frac{\delta MV^{el}_{C^w}}{\delta l_{h,y}} \geq 0;\ \frac{\delta MV^{el}_{C^w}}{\delta b} \geq 0 \tag{13}$$

$$\frac{\delta MV^{el}_{C^s}}{\delta C^s} \leq 0;\ \frac{\delta MV^{el}_{C^s}}{\delta C^w} \leq 0;\ \frac{\delta MV^{el}_{C^s}}{\delta l_{h,y}} \geq 0;\ \frac{\delta MV^{el}_{C^s}}{\delta b} \geq 0 \tag{14}$$

To summarize, Eqs. (11) and (12) show that system effects are very relevant when discussing the MV^{el} of renewable energy technologies. Overall, the MV^{el} of wind power capacities decreases as their penetration (C^w) increases. However, the level of the MV^{el} of wind power units depends on the wind power production factor profile ($pf^w_{y,h}$), the solar power penetration (C^s), the solar power production factor profile ($pf^s_{y,h}$), the load level ($l_{y,h}$) and the structure of the marginal costs of the dispatchable capacity mix. The same holds true for the MV^{el} of solar power capacities.

2.2.2 *Definition 2*

An alternative expression for the MV^{el} of fluctuating wind and solar power units is derived by Lamont (2010). Equation (3) can be rewritten as follows:

$$MV^{el}_{C^f} = \sum_{y\in Y} H\cdot E(pf^f_{y,h}\cdot\mu_{y,h}) \tag{15}$$

As explained in Lamont (2010), the term $E(pf^f_{y,h}\cdot\mu_{y,h})$ from Eq. (15), which reflects an expected (average) value, is a component of the correlation between the hourly production factor of fluctuating renewable energy technologies ($pf^f_{y,h}$) and the wholesale price ($\mu_{y,h}$) (Eq. (16)). The correlation coefficient ($cor(pf^f_{y,h},\mu_{y,h})$) is obtained by dividing the covariance of the two variables ($cov(pf^f_{y,h},\mu_{y,h})$) by the product of their standard deviations ($\sigma_{pf^f_{y,h}}\cdot\sigma_{\mu_{y,h}}$).

$$cor(pf^f_{y,h},\mu_{y,h}) = \frac{cov(pf^f_{y,h},\mu_{y,h})}{\sigma_{pf^f_{y,h}}\cdot\sigma_{\mu_{y,h}}} = \frac{E(pf^f_{y,h}\cdot\mu_{y,h}) - E(pf^f_{y,h})\cdot E(\mu_{y,h})}{\sigma_{\mu_{y,h}}\cdot\sigma_{pf^f_{y,h}}} \tag{16}$$

Thus, the MV^{el} of fluctuating renewable energy technologies (C^f) can alternatively be expressed by Eq. (17).

$$MV^{el}_{C^f} = \sum_{y\in Y} H\cdot(\underbrace{E(pf^f_{y,h})\cdot E(\mu_{y,h})}_{\text{First component}} + \underbrace{cor(pf^f_{y,h},\mu_{y,h})\cdot\sigma_{pf^f_{y,h}}\cdot\sigma_{\mu_{y,h}}}_{\text{Second component}}) \tag{17}$$

[7]The effects of wind and solar power generation with (almost) no variable generation costs on the wholesale price has been examined by, e.g., Gil et al. (2013), Woo et al. (2010), Jonsson et al. (2014), MacCormack et al. (2007), Munksgaard and Morthorst (2013), Saenz de Miera et al. (2013) or Sensfuß et al. (2008), based on historical as well as simulated data. All papers confirm the decreasing effect of increased wind and solar power generation on the wholesale price (short-term merit-order effect).

[8]The wholsale price function corresponds to the merit-order curve of dispatchable power plants and reflects the short-run marginal costs of power production of the respective electricity system's dispatchable power plants.

This expression (Eq. (17)) differs from the one originally derived by Lamont (2010) with regard to the second component. We take the correlation coefficient between the production factor profile and the wholesale price (i.e., the system marginal costs) instead of the covariance. This is motivated by the fact that the covariance only shows the sign of the linear relationship between the two variables, while the normalized version of the covariance, i.e., the correlation coefficient, is indicative of the strength of the linear relationship. More specifically, in contrast to the covariance, the correlation coefficient shows the strength of the linear relation by its magnitude. As such, the correlation coefficients of alternative fluctuating renewable energy technologies can be better compared and interpreted than the covariances, which is advantageous for the numerical analysis in Sect. 3.

As explained by Lamont (2010), the first component of Eq. (17) is a function of the capacity factor, i.e., the expected (average) production factor of the fluctuating renewable energy technology ($E(pf^{f}_{y,h})$) over all hours (H) of the year, and the base price, i.e., the expected (average) wholesale price (E($\mu_{y,h}$)) over all hours (H) of the year. This component is independent of the actual profile of the hourly power production of fluctuating renewable energy technologies and only reflects the technology's full load hours (FLH). It shows that the MV^{el} of a technology increases as (ceteris paribus) its capacity factor or number of FLH increases. The second component, however, is a function of the correlation between the hourly production factor profile ($pf^{f}_{y,h}$) and the wholesale price profile ($\mu_{y,h}$) and reflects the 'price matching' or 'residual-load matching' capability of a fluctuating power generation unit. Hence, the better the production factor profile of a wind (solar) power unit matches the residual load (and thus the hourly wholesale price) profile, the larger (ceteris paribus) the correlation and thus the higher the MV^{el} of the wind (solar) power unit becomes.

After having analyzed the MV^{el} of the wind (solar) power units in detail via a theoretical framework, we provide quantitative evidence for the theoretical results derived so far. Using historical data for Germany, we illustrate the change in the MV^{el} of wind and solar power technologies as a consequence of increased wind and solar power penetration in a 'ceteris paribus' example (i.e., keeping all other determinants/parameters constant).

3 Numerical Illustration for Germany

3.1 Methodology

In the numerical example for Germany we use Eq. (18) to determine the MV^{el} of wind and solar power technologies (i.e., the annual revenue from selling electricity on the wholesale market) for exogenously varied onshore wind and solar power capacities (C^{f}).

$$MV^{el} = \sum_{h=1}^{8760} (pf^{f}_{y,h} \cdot \mu_{y,h}) \tag{18}$$

The corresponding wholesale price ($\mu_{y,h}$) in € ct/kWh, which depends on the residual load ($RL_{y,h}$), is determined by Eq. (19) (see also Eq. (8)).

$$\mu_{y,h} = -1.37 + 1.31 \cdot 10^{-07} \cdot \underbrace{(l_{h,y} - pf^{w}_{y,h} \cdot C^{w} - pf^{s}_{y,h} \cdot C^{s})}_{RL_{y,h}} \tag{19}$$

The coefficients of the wholesale price function (Eq. (19)) are derived by an ordinary least squares (OLS) regression based on historical wholesale price data (EEX (2013c)) and residual load data for Germany in 2011 and 2012 (ENSTO-E (2013), EEX (2013a) and EEX (2013b)).[9] More specifically, we apply an OLS regression of the wholesale price on the residual load (i.e., total electricity demand minus wind and solar power generation) which is assumed to serve as a proxy for the output of dispatchable power plants ($\sum_{d \in D} G^{d}_{y,h}$).[10] Modeling wind and solar power generation as a reduction from total electricity demand reflects the German renewable energy law which guarantees fixed feed-in tariffs (FIT) and implies a priority infeed of renewable generation.[11]

The scatter plot of historical wholesale prices and residual load data (Fig. 1) shows negative prices at very low residual load levels (below 20 GWh) due to the priority infeed of renewable generation under the German renewable energy law, and exponentially increasing prices at very high residual load levels (above 65 GWh). Between those extremes, the plot suggest a fairly linear relation.

For reasons of model validation, historical wholesale prices (for 2011 and 2012) are compared to the simulated wholesale prices (on basis of the residual load in 2011 and 2012). As can be seen in Fig. 2, which illustrates the annual price duration curve of the historical wholesale prices and the corresponding fitted values, wholesale prices are underestimated for very high residual load levels and overestimated for very low residual load levels in our model.[12]

[9] The restriction to the years 2011 and 2012 is due to the fact that solar power generation data from EEX (2013a) are only available from 2011 onwards.

[10] Another application of least-squares regressions of the wholesale price on the residual load can, for example, be found in Wagner (2010). Alternative empirical functions from hourly wholesale prices and (residual) load data are, for example, derived by Barlow (2002), Burger et al. (2013a) and Elberg and Hagspiel (2013c).

[11] We note that production from wind and solar power generation (with marginal production costs of zero) would be offered at a price of zero on the energy exchange if there was no such system. In this case, our approach would only be suitable when additionally assuming that no negative prices are allowed at the energy exchange.

[12] This is primarily due to the application of a linear regression function.

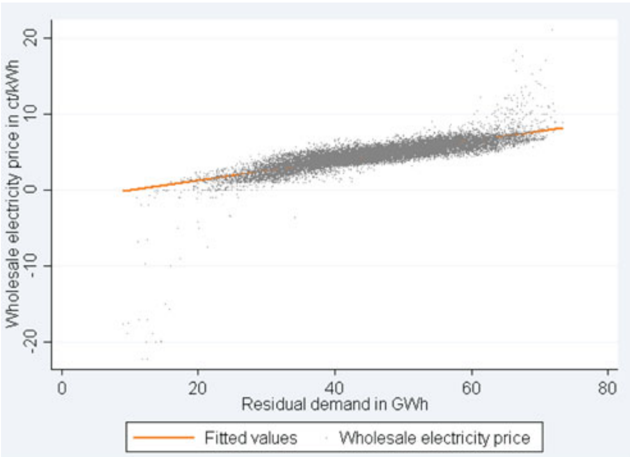

Fig. 1 Scatter plot with linear regression line

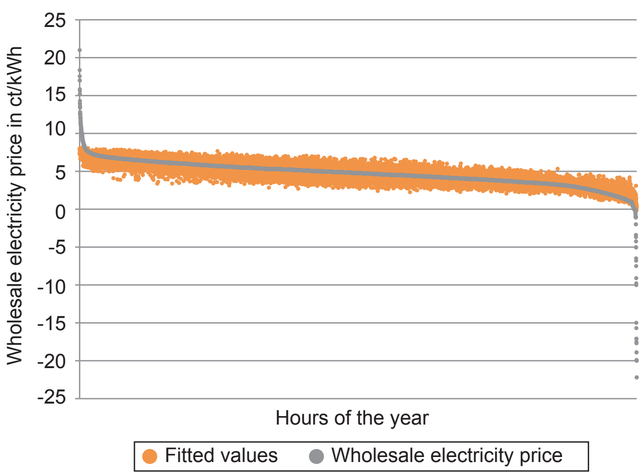

Fig. 2 Annual price duration curves: Comparison of simulated and real wholesale prices in 2011 and 2012

Table 1 Results of the OLS regression

Wholesale price ($\mu_{y,h}$)	Coefficient
Residual demand ($RD_{y,h}$)	1.31e–07***
	(7.21e–10)
Constant	–1.37***
	(0.034182)

Remarks: Robust standard errors are in parentheses; ***Significant at the 1 %-level; Number of observations: 17544; R-squared: 0.6526; Adjusted R-squared: 0.6526

Overall, however, the applied linear function provides a reasonable fit to the data. As illustrated in Table 1, the (adjusted) R-squared, which measures the quality of fit, amounts to 0.65. Hence, 65 % of the variation in the wholesale price can be explained by the residual load in our model.

We note that there might be a problem of endogeneity in OLS regressions which describes the circumstance that the independent variable (here the wholesale price) is correlated with the error term in the regression model and which implies that the regression coefficients are biased. Important sources of endogeneity are omitted explanatory variables and simultaneity. As explained in McMenamin et al. (2008), explanatory variables for electricity prices can basically be divided in two categories: The first set of explanatory factors is related to the demand-side. The hourly load reflects people's life-patterns and industrial production processes interacting, for example, with the day of the week or the weather. In our model hourly electricity demand ($l_{h,y}$, see Eq. (19)) is used as explanatory variable, rather than indirect variables for calendar and weather effects. The second set of explanatory factors refers to the supply-side. These factors include, for example, wind and solar power generation, fuel prices, generation unit availability and transmission constraints.[13] In this analysis only wind and solar power generation is included as explanatory variables ($pf^w_{y,h} \cdot C^w$ and $pf^s_{y,h} \cdot C^s$, see Eq. (19)). Other important supply-side factors, such as natural gas prices or un-/planned power plant outages, are not considered. However, omitted variables only cause problems of endogeneity (i.e., lead to biased regression coefficients) if they are correlated with at least one of the explanatory variables (i.e., the level of hourly demand or the level of hourly wind and solar power generation) which is arguably not the case in this analysis. More specifically, power plant outages and fossil fuel prices are assumed to be not correlated with the level of hourly demand or hourly wind and solar power generation. Hence, we argue that no problem of endogeneity exists in our analysis as a consequence of omitted variables. However, endogeneity problems might exist due to simultaneity, as the electricity demand itself might be dependent on the wholesale price if the electricity demand is price-elastic in the short-term. However, short-term price elasticity is found to be rather low in today's electricity system (see, e.g., Lijesen (2008)). Hence, we argue that the potential problem of endogeneity due to simultaneity is negligible in our analysis.

Besides the potential problem of endogeneity, it should be stressed that the applied wholesale price function reflects the current capacity mix in Germany (as it was estimated based on historical data from 2011 and 2012) and thus does not account for an adaptation of the capacity mix as the renewable energy penetration increases (shift towards peak-load capacities). Therefore, the derived decrease in the MV^{el} as a consequence of increased wind and solar power penetration should be interpreted as an upper-bound estimate.

3.2 Results

In the numerical example for Germany we use Eqs. (18) and (19) to determine the MV^{el} of wind and solar power technologies (i.e., the annual revenue from selling electricity

[13] Moreover, in periods of high demand the load levels in neighboring countries can have a significant impact on national electricity prices (McMenamin et al. (2008)).

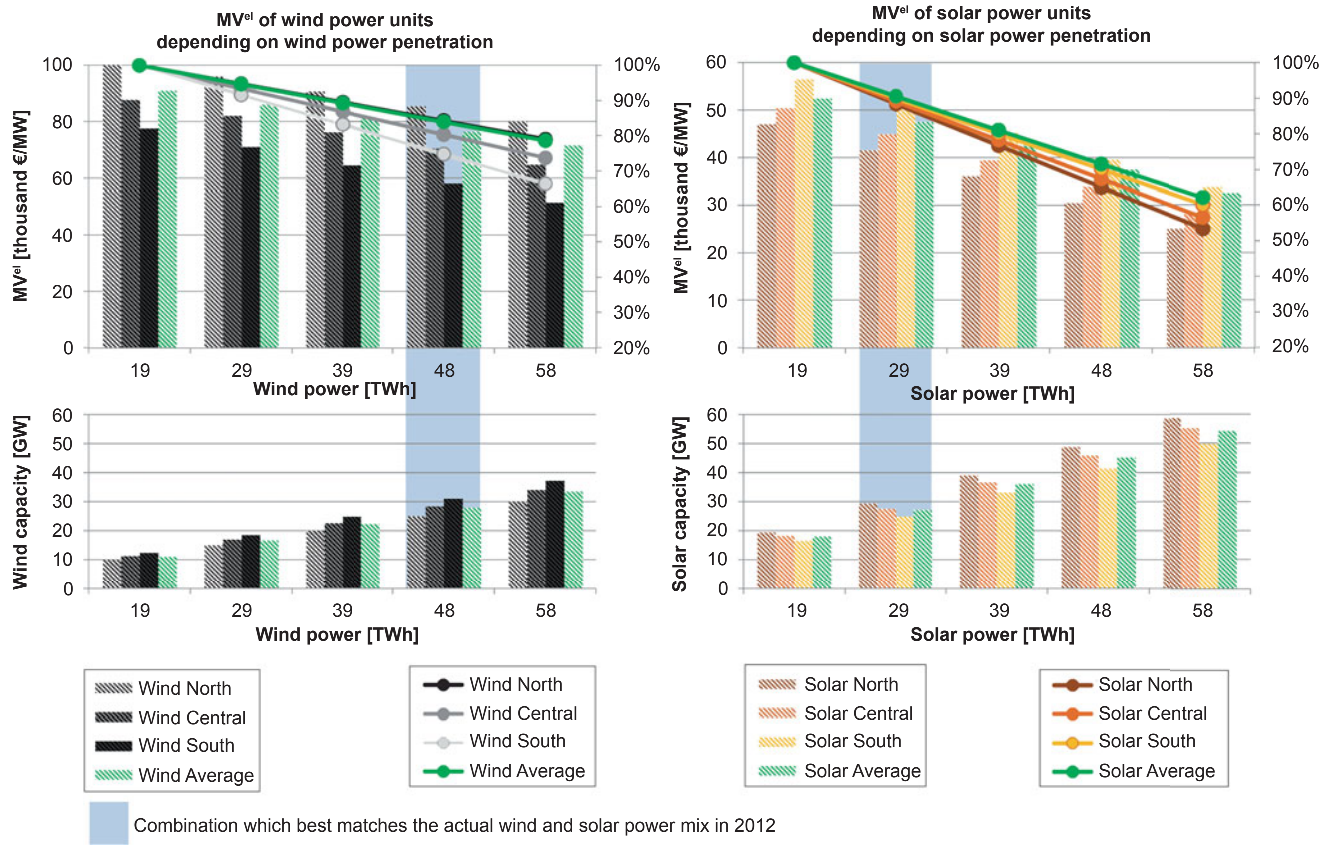

Fig. 3 MV^{el} of wind and solar power units depending on their penetration level [€/MW]

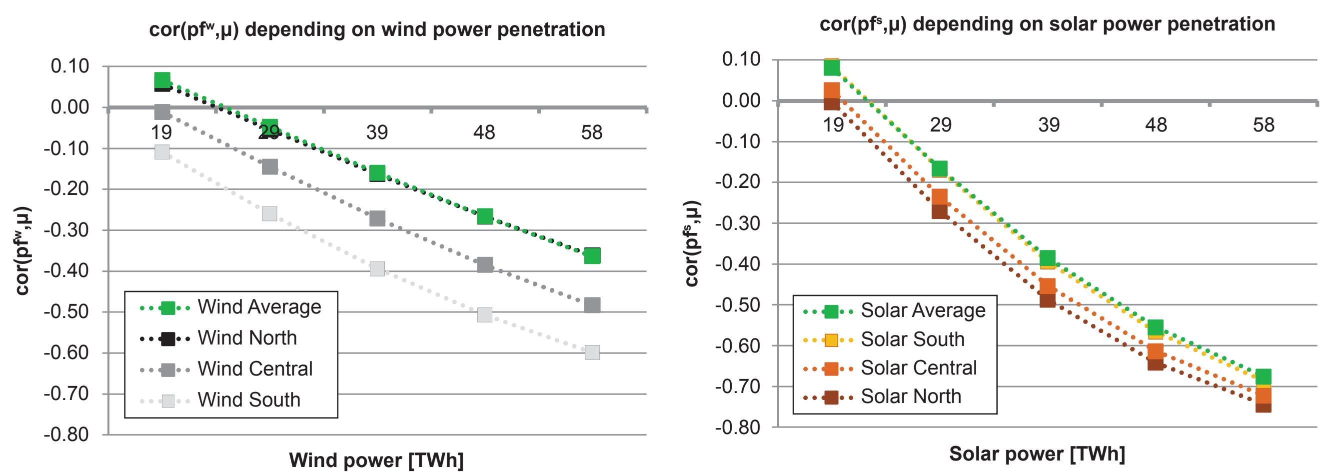

Fig. 4 Correlation between the hourly wind/solar power production factor and the wholesale price

on the wholesale market) for exogenously varied onshore wind and solar power capacities (C^f) for three regions in Germany (north, central and south), taking the actual wind and solar power capacity mix in 2012 as a reference point.[14] The three regions differ with regard to the production factor

[14]Appendix A.2 provides a detailed discussion of the exogenous variation of wind and solar power capacities assumed in the numerical example (see also Table 3).

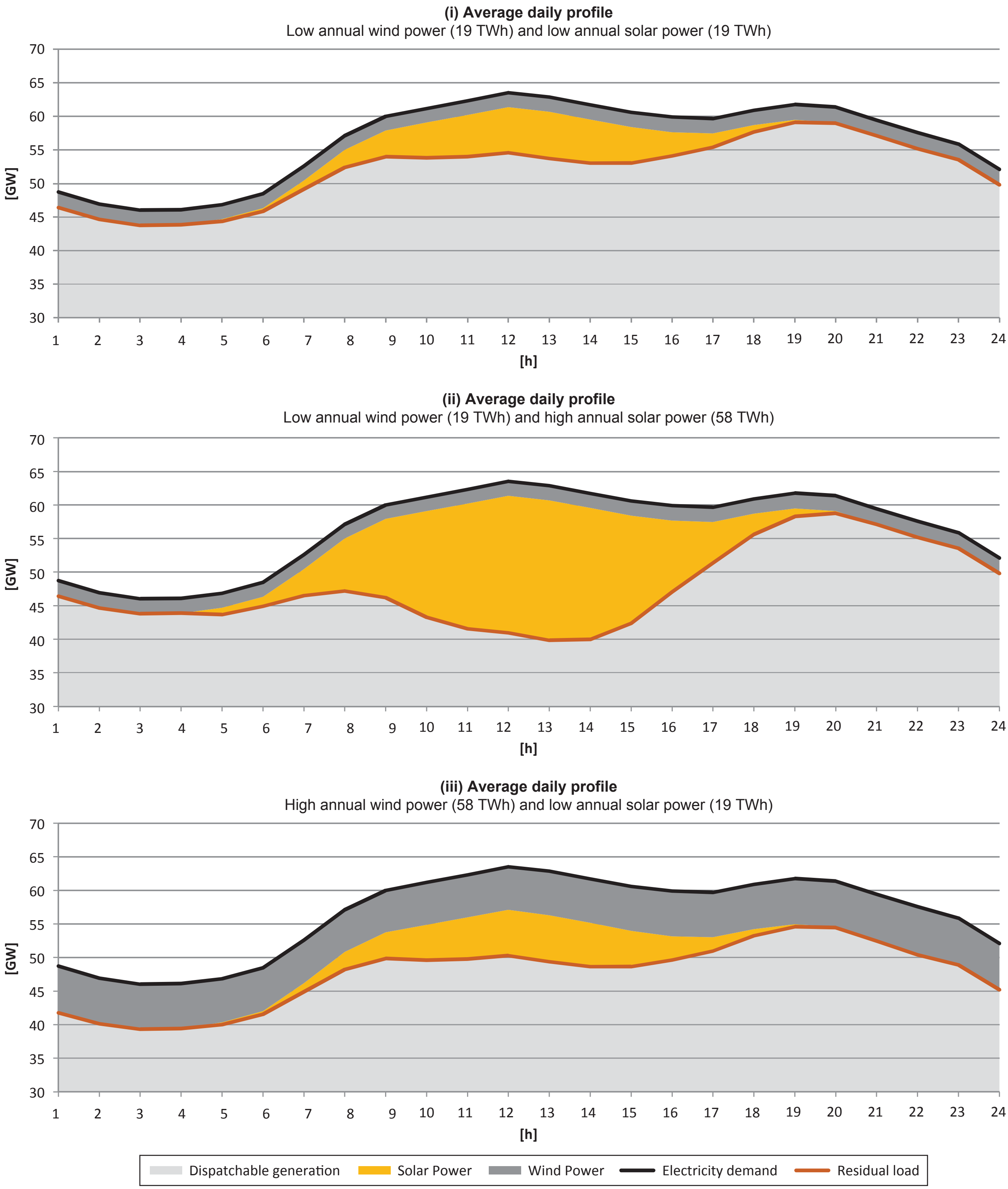

Fig. 5 Impact of an increased wind and solar power penetration on the average daily residual load profile (based on 8760 h)

profile of wind and solar power units ($\mathrm{pf}^{f}_{y,h}$) and the number of full load hours (based on data for 2008 from EuroWind (2011)).

We note that the wind and solar power capacities are proportionally increased as to generate the same amount of electricity with each technology (between 19 TWh and 58 TWh) in the numerical example. Moreover, to illustrate the benefits of regional diversification, an average production factor profile is included for wind and solar power across the three regions. As such, the average production factor profile for wind/ solar power implicitly assumes an equal distribution of wind/ solar power capacities across the three regions.[15]

Figure 3 illustrates three effects: First, the MV^{el} of wind power and solar power units decreases (ceteris paribus) as their penetration increases. As shown in Fig. 4, the decrease in the MV^{el} can be explained by the decrease in the correlation between the wind/ solar power production factor profile ($pf^{w}_{y,h}/pf^{s}_{y,h}$) and the wholesale price profile ($\mu_{y,h}$). The higher the penetration of wind or solar power units becomes the lower their price matching or residual-load matching capability will be.[16] In addition, the base price (i.e., the time-weighted wholesale price $\mathrm{E}(\mu_{y,h})$) also decreases, as shown in Appendix A.3 (Fig. 6).[17]

Second, the decrease in the MV^{el} is more pronounced for solar power than for wind power units as penetration increases (see Fig. 3). For example, while the MV^{el} of a wind power unit in central Germany decreases by only 26 % (to 74 %) as the overall wind power generation in central Germany increases from 19 to 58 TWh, the MV^{el} of a solar power unit in central Germany decreases by more than 44 % (to 56 %) as the overall solar power generation in central Germany increases from 19 to 58 TWh. This is due to the fact that the decrease in the correlation between the production factor profile and the wholesale price profile is more drastic for the case of solar power than for wind power (see Fig. 4). More specifically, as a consequence of high solar power generation during midday, the residual load pattern reverses, as illustrated in Fig. 5 (i) and (ii). The former midday-peak of the residual load curve (under moderate solar power penetration) becomes a trough. The wind power production factor profile, in contrast, is more volatile and follows no such distinct daily pattern like solar power (with zero output during the night and peak generation at midday). Hence, high wind power penetration does not result in such a pronounced structural change in the residual load curve, as shown in Fig. 5 (i) and (iii). The effect can also be seen in Fig. 7 of the Appendix, which illustrates the impact of increased wind and solar power penetration on the annual residual load profile for 8760 h of the year.

Third, there are benefits of regional diversification which become evident when comparing the full load hours (FLH) and the MV^{el} of units with region-specific production factor profiles and units with the average production factor profile. For example, the MV^{el} of a wind power unit with the average production factor profile is more than 10 % higher than the MV^{el} of a wind power unit in central Germany at a penetration level of 58 TWh (71.6 thousand €/MW vs. 64.9 thousand €/MW), although the wind power unit with the average production factor profile has only 2 % higher FLH than the wind power unit in central Germany in the numerical analysis.[18]

Moreover, when looking at the combination of wind and solar power generation which best matches the historical wind and solar power mix in 2012 in Fig. 3, it becomes evident that the system price effect of wind and solar power is already highly relevant for both wind and solar power in Germany. Hence, the MV^{el} of additional wind and solar power units in Germany has significantly decreased in recent years. As a consequence, the level of renewable energy support payments needed to incentivize further investments in wind and solar power technologies increases as (ceteris paribus) penetration increases, see Eq. (2).

4 Conclusion

The marginal value (MV^{el}) of wind and solar power technologies depends on wide range of parameters that are electricity system specific. Most importantly, the MV^{el} of wind and solar power technologies decreases as penetration increases. The higher the overall installed capacity of wind and solar power becomes, the lower the correlation between the production factor profile and the wholesale electricity price and thus the marginal value of an additional unit of wind and solar capacity becomes. This so called system price effect is already highly relevant for both wind and solar power generation in Germany and suggests that renewable energy

[15]The benefits of regional diversification with respect to the smoothing out of fluctuations in wind power generation are, for example, discussed in Liu et al. (2010), Grothe and Schnieders (2010) Katzenstein et al. (2008) and Roques et al. (2008).

[16]We note that the correlation between the wind/solar power production factor profile and the wholesale price profile (illustrated in Fig. 4) corresponds to the correlation between the wind/ solar power production factor profile and the residual load profile in the numerical analysis.

[17]The level of decrease in the MV^{el} of wind/ solar power units differs between the single regions due to differences in the correlation of the regional production factor profiles and the load profile, as illustrated in Table 4 of the Appendix.

[18]Equally, the MV^{el} of a solar power unit with the average production factor profile is more than 14 % higher than the MV^{el} of a solar power unit in central Germany at a penetration level of 58 TWh (32.6 thousand €/MW vs. 28.5 thousand €/MW), although the solar power unit with the average wind production factor profile has only 2 % higher FLH than the solar power unit in central Germany (1,072 h vs. 1,055 h).

support payments needed to cover costs increase as (ceteris paribus) penetration increases.

Overall, the results highlight the need to expose wind and solar power to the market price signal if a cost-efficient renewable energy mix is to be achieved. Only if investors are incentivized to account for the marginal value (MV^{el}) of renewable energy technologies, they chose the technologies which are cost-efficient from the total system perspective. However, renewable energy support schemes are often designed to incentivize investors to only account for the marginal costs (MC) but not for the marginal value (MV^{el}) of renewable energy technologies. Future research could thus address the following research question: What are the excess costs if renewable energy support schemes fail to incentivize investments in those renewable energy technologies which are most attractive from the total system perspective?

Appendix

Appendix A.1 Optimality Condition for the Expansion of Wind and Solar Power Units

Given a politically implemented (technology-neutral) RES-E target, the optimality condition for the expansion of fluctuating renewables can be derived by maximizing social welfare or by minimizing total system costs. The cost-minimization approach corresponds to the welfare-maximization approach given the assumption of perfect competition and a price-inelastic electricity demand.

In this analysis, we derive the optimality condition for the expansion of fluctuating renewable energy capacities (C^f) with no short-run marginal costs of power production and weather dependent production factor profiles ($pf^f_{y,h}$) by minimizing total system costs which are accumulated over all years (Y) and hours (H) of the capacities' technical lifetime (Eq. (20)). Assuming two kinds of generation technologies – i.e., dispatchable power plants and fluctuating renewable energy technologies – total system costs include annualized investment costs of dispatchable power plants (fc^d_y) and fluctuating renewable energy units (fc^f_y), as well as the variable generation costs (i.e., short-run marginal costs of power production) of dispatchable power plants (VC^d), which are a function of the dispatchable power plants' generation level ($G^d_{y,h}$).

Total system costs are minimized subject to several techno-economic constraints. Eqs. (21–22) restrict the hourly output of dispatchable power plants and fluctuating renewable energy units (capacity constraints), while Eq. (23) ensures that demand ($l_{y,h}$) equals supply (power balance constraint). Equation (24) states that the accumulated CO_2 emissions may not exceed a certain CO_2 cap (co_y) per year (CO_2 emission constraint).[19] Moreover, Eq. (25) defines the minimum share (x) of renewable energy generation in % of the annual electricity demand ($\sum_{h\in H} l_{y,h}$) (renewable energy constraint).[20]

The optimality condition for the cost-efficient expansion of fluctuating wind and solar power capacities (C^f) under a (technology-neutral) target for fluctuating renewable energy generation is derived by differentiating the Lagrangian function (Eq. (26)) with respect to C^f (Eq. (27)). The variable $\mu_{y,h}$ corresponds to the shadow variable of the power balance constraint (Eq. (23)) and represents the system's marginal costs associated with meeting the hourly electricity demand ($l_{h,y}$). Assuming perfect competition and a price-inelastic electricity demand, the shadow variable of the power balance constraint ($\mu_{y,h}$) serves as a proxy for the wholesale price. The variable ρ_y, in contrast, corresponds to the shadow variable of the renewable energy constraint (Eq. (25)) and indicates the marginal system costs associated with the achievement of the renewable energy target. It may be interpreted as the price of tradable green certificates (TGC).[21] Moreover, $\lambda^d_{y,h}$ and $\lambda^f_{y,h}$ are the shadow variables of the capacity constraints (Eq. (21–22)). Following the explanation of Lamont (2007), $\lambda^d_{y,h}$ and $\lambda^f_{y,h}$ correspond to the amount of net revenue that dispatchable generators (C^d) and fluctuating renewable energy generators (C^f) receive per hour above their operating costs per unit of electricity produced (i.e., above their short-run marginal costs of power production), assuming that all generators receive a wholesale price equal to the system's marginal costs $\mu_{y,h}$. Hence, $\lambda^d_{y,h}$ and $\lambda^f_{y,h}$ are the difference between the generators' short-run marginal costs of power production and the system's marginal costs $\mu_{y,h}$. However, in contrast to dispatchable power plants, the short-run marginal costs of fluctuating renewable energy generation, i.e., of wind and solar power production, are zero. As a consequence, the net revenue wind and solar power generators receive per hour corresponds to the system's marginal costs $\mu_{y,h}$ (wholesale price). Hence, the optimality condition for the expansion of fluctuating renewable energy generation units – given a politically implemented technology- and region-neutral RES-E target – can be rewritten as follows:

$$\min \; TSC_{C^f} = \sum_{d\in D}\sum_{y\in Y} C^d \cdot fc^d_y + \sum_{f\in F}\sum_{y\in Y} C^f \times fc^f_y + \sum_{d\in D}\sum_{y\in Y}\sum_{h\in H} VC^d(G^d_{y,h}) \tag{20}$$

[19] The CO_2 emission constraint reflects a cap- and trade-system for CO_2 emission allowances.

[20] The renewable energy constraint reflects a (technology- and region-neutral) quota system for fluctuating rewewable energy generation in combination with tradable green certificates (TGC).

[21] Alternatively, it may be interpreted as the optimal level of a bonus payment given the analogy of quantity- and price-based mechanisms under the assumption of perfect information. However, for reasons of completeness, note that in markets with uncertainties, price-based and quantity-based instruments are no longer equivalent (Weitzman (1974)).

Table 2 Model sets, parameters and variables

Sets	
h in H	Hour H = [1,...,i]
d in D	Dispatchable power plants
f in F	Fluctuating renewable energy technologies (wind and solar power)
y in Y	Technical lifetime of fluctuating renewable energy technologies, Year Y = [1,...,j]
Parameters	
co_y	Cap for CO_2 emissions [t CO_2]
ef^d	CO_2 emissions per fuel consumption [t CO_2 /MWh_{th}]
η^d	Net efficiency (generation) [%]
fc_y^d	Annualized investment costs of dispatchable power plants [€/kW]
fc_y^f	Annualized investment costs of fluctuating renewable energy technologies [€/kW]
$l_{y,h}$	Price-inelastic electricity demand [kW]
pf_h^d	Production factor of dispatchable capacities [kW/kW_{inst} or %]
$pf_{y,h}^f$	Production factor of fluctuating renewable energy capacities [kW/kW_{inst} or %]
x	(Technology-neutral) renewable energy quota [%]
Variables	
C^d	Dispatchable capacities [kW]
C^f	Fluctuating renewable energy capacities [kW]
C^w	Fluctuating wind power capacities [kW]
C^s	Fluctuating sola power capacities [kW]
$G_{y,h}^d$	Generation of dispatchable capacities [kWh]
$G_{y,h}^f$	Generation of fluctuating renewable energy capacities [kWh]
$VC^d(G_{y,h}^d)$	Variable costs of dispatchable power generation [€]
$RL_{y,h}$	Residual Load [kW]
π	Profit [€/kWh]
Shadow variables	
γ_y	Shadow variable of the CO_2 emission consraint [€ /t CO_2]
$\lambda_{y,h}^d$	Shadow variable of the dispatchable capacity constraint [€/kW]
$\lambda_{y,h}^f$	Shadow variable of the fluctuating renewable energy capacity constraint [€/kW]
$\mu_{y,h}$	Shadow variable of the power balance constraint [€/kW]
ρ_y	Shadow variable of the fluctuating renewable energy constraint [€/kW]
Variables calculated ex-post	
MV_{Cf}^{el}	Marginal value of power supply of fluctuating renewable energy capacities [€/kW]
MV_{Cf}^{ren}	Marginal value of renewable electricity supply of fluctuating renewable energy capacities [€/kW]
MC_{Cf}	Marginal costs of fluctuating renewable energy capacities [€/kW]

$$
\begin{aligned}
\min \quad L_{C^f} &= \textstyle\sum_{d\in D}\sum_{y\in Y} C^d \cdot fc_y^d + \sum_{f\in F}\sum_{y\in Y} C^f \cdot fc_y^f \\
&+ \textstyle\sum_{d\in D}\sum_{y\in Y}\sum_{h\in H} VC^d(G_{y,h}^d) \\
&+ \textstyle\sum_{d\in D}\sum_{y\in Y}\sum_{h\in H} (\lambda_{y,h}^d \cdot (G_{y,h}^d - pf_h^d \cdot C^d)) \\
&+ \textstyle\sum_{f\in F}\sum_{y\in Y}\sum_{h\in H} (\lambda_{y,h}^f \cdot (G_{y,h}^f - pf_{y,h}^f \cdot C^f)) \\
&+ \textstyle\sum_{y\in Y}\sum_{h\in H} (\mu_{y,h} \cdot (l_{h,y} - \sum_{d\in D} G_{y,h}^d - \sum_{f\in F} G_{y,h}^f)) \\
&+ \textstyle\sum_{y\in Y} \gamma_y \cdot (co_y - \sum_{d\in D}\sum_{h\in H} \frac{G_{y,h}^d}{\eta^d} \cdot ef^d) \\
&+ \textstyle\sum_{y\in Y} \rho_y \cdot (x \cdot \sum_{h\in H} l_{y,h} - \sum_{f\in F}\sum_{h\in H} pf_{y,h}^f \cdot C^f)
\end{aligned} \tag{26}
$$

s.t.

$$G_{y,h}^d - pf_{y,h}^d \cdot C^d \le 0 \tag{21}$$

$$G_{y,h}^f - pf_{y,h}^f \cdot C^f \le 0 \tag{22}$$

$$l_{y,h} - \sum_{d\in D} G_{y,h}^d - \sum_{f\in F} G_{y,h}^f = 0 \tag{23}$$

$$\sum_{d\in D}\sum_{h\in H} \frac{G_{y,h}^d}{\eta^d} \cdot ef^d) \le co_y \tag{24}$$

$$x \cdot \sum_{h\in H} l_{y,h} - \sum_{f\in F}\sum_{h\in H} pf_{y,h}^f \cdot C^f \le 0 \tag{25}$$

$$
\begin{aligned}
dL/dC^f &= \textstyle\sum_{y\in Y} fc_y^f - \sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \lambda_{y,h}^f \\
&- \textstyle\sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \rho_y = 0
\end{aligned} \tag{27}
$$

$$\underbrace{\sum_{y\in Y} fc_y^f}_{MC_{Cf}} = \underbrace{\sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \mu_{y,h}}_{MV_{Cf}^{el}} + \underbrace{\sum_{y\in Y}\sum_{h\in H} pf_{y,h}^f \cdot \rho_y}_{MV_{Cf}^{ren}} \tag{28}$$

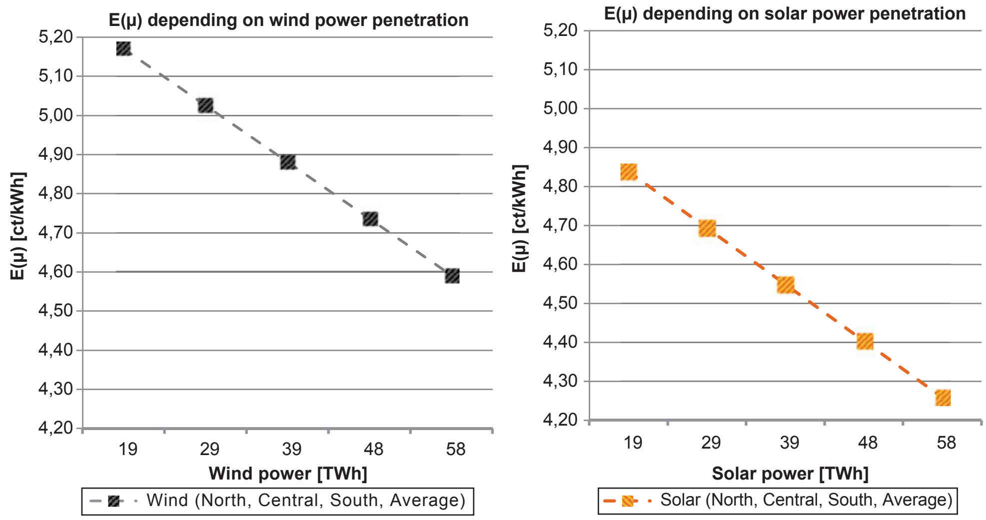

Fig. 6 Time-weighted average wholesale price $E(\mu_{y,h})$

Appendix A.2 Assumed variation of onshore wind and solar power capacities

For reasons of comparability, the onshore wind and solar power capacities across the three regions are varied in such a way that they produce the same overall power output (Table 3).

The logic behind the exogenous variation of onshore wind and solar power capacities (across the different regions) is as follows: For example, when the impact of increased penetration of onshore wind power in northern Germany is analyzed, the onshore wind power capacities in the other two regions (central and southern Germany) are assumed to be zero, while the solar power capacities are assumed to amount to 33 GW (which is the historical installed capacity in 2012). Of these 33 GW solar power capacities one third is assumed to be located in central Germany and two thirds in southern Germany, producing a total of 37 TWh per year. Equally, when, for example, the impact of increased solar power penetration in southern Germany is analyzed, the solar power capacities in the other two regions (central and northern Germany) are assumed to be zero, while the onshore wind power capacities are assumed to amount to 32 GW (which is the historical installed capacity in 2012). Of these 32 GW wind power capacities two thirds are assumed to be installed in northern Germany and one third in central Germany, producing a total of 60 TWh per year.

Table 3 Assumed variation of onshore wind and solar power capacities in Germany

Region	Full load hours [h]	Exogenous variation of capacities [GW]	Annual generation [TWh]
		Onshore wind power	
North	1,938	10.0/15.0/20.0/25.0/30.0	
Central	1,706	11.4/17.0/22.7/28.4/34.1	
South	1,560	12.4/18.6/24.8/31.1/37.3	19/29/39/48/58
Average	1,950	11.2/16.8/22.3/27.9/33.5	
		Solar power	
North	992	19.5/29.3/39.1/48.9/58.6	
Central	1,055	18.4/27.6/36.8/45.9/55.1	
South	1,169	16.6/24.9/33.2/41.5/49.8	19/29/39/48/58
Average	1,072	18.1/27.1/36.2/45.2/54.3	

Appendix A.3 Dependence of the Time-Weighted Average Wholesale Price $E(\mu_{y,h})$ on Wind and Solar Power Penetration

It should be noted that due to the assumed (linear) wholesale price function (Eq. (19)) the decrease in the time-weighted average wholesale price ($E(\mu_{y,h})$) does not differ between the regions (see Fig. 6). However, the level of the time-weighted average wholesale price ($E(\mu_{y,h})$) differs between technologies. This can be explained by the fact that the (historical) solar power capacities (33 GW/ 37 TWh), which are held constant when the wind penetration is increased, differ from the (historical) wind power capacities (32 GW/ 60 TWh), which are held constant when the wind penetration is increased.

Appendix A.4 Impact of increased wind and solar power penetration on the annual residual electricity demand profile (based on 8760 h)

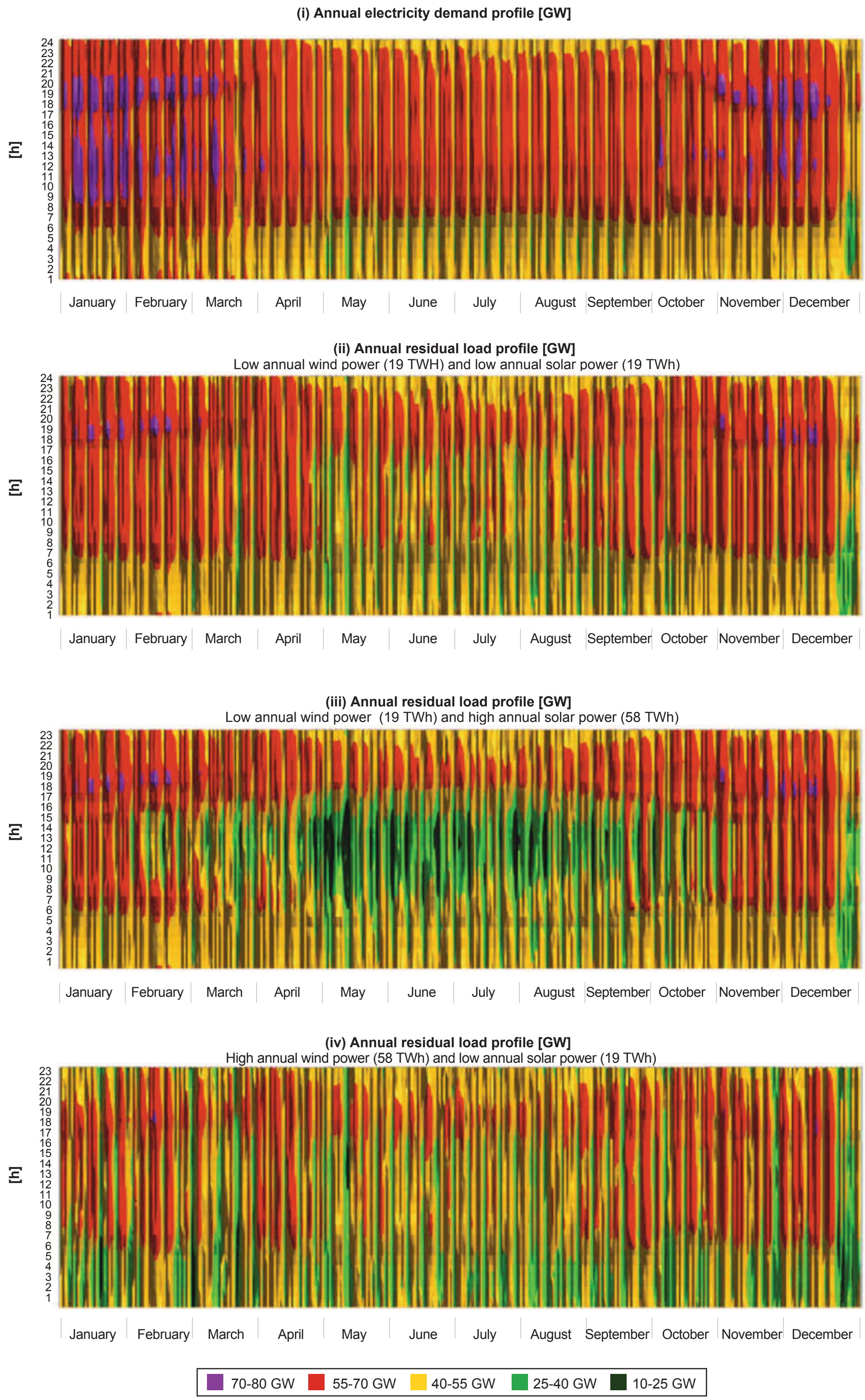

Fig. 7 Impact of increased wind and solar power penetration on the annual residual electricity demand profile (based on 8760 h)

Appendix A.5 Correlation between the demand profile and the production factor profile

Table 4 Correlation between the demand profile and the production factor profile

Wind north	0.19
Wind center	0.17
Wind south	0.08
Wind average	0.17
Solar north	0.21
Solar center	0.23
Solar south	0.28
Solar average	0.26

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