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Decreasing market value of variable renewables can be avoided by policy action

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ABSTRACT

Although recent studies have shown that electricity systems with shares of wind and solar above 80% can be affordable, economists have raised concerns about market integration. Correlated generation from variable renewable sources depresses market prices, which can cause wind and solar to cannibalise their own revenues and prevent them from covering their costs from the market. This cannibalisation appears to set limits on the integration of wind and solar, and thus to contradict studies that show that high shares are cost effective. Here we show from theory and with simulation examples how market incentives interact with prices, revenue and costs for renewable electricity systems. The decline in average revenue seen in some recent literature is due to an implicit policy assumption that technologies are forced into the system, whether it be with subsidies or quotas. This decline is mathematically guaranteed regardless of whether the subsidised technology is variable or not. If instead the driving policy is a carbon dioxide cap or tax, wind and solar shares can rise without cannibalising their own market revenue, even at penetrations of wind and solar above 80%. The strong dependence of market value on the policy regime means that market value needs to be used with caution as a measure of market integration. Declining market value is not necessarily a sign of integration problems, but rather a result of policy choices.

1. Introduction

Rising shares of wind and solar in electricity markets around the world have led to concerns about their market integration at high penetrations. Several studies have found empirical evidence that electricity prices have decreased in markets as the share of variable renewable energy (VRE) has risen (Sensfuß, 2007; Sensfuß et al., 2008; Hildmann et al., 2015; Figueiredo and da Silva, 2018; Ozdemir et al., 2017; Hirth, 2018; López Prol et al., 2020; Mills and Wiser, 2015). The cause of the lower prices is the very low or zero marginal cost of wind and solar generators. This pushes out some of the more expensive generators from the market, and, since the price is usually set by the marginal cost of the last generator needed to satisfy demand, the prices are depressed during times of wind and solar generation. Lower prices lead to lower revenues for all generators (the 'merit order effect', Sensfuß et al., 2008), but especially so for wind and solar generators, since their generation depresses prices exactly when they are generating most, an effect known as 'cannibalisation' (López Prol et al., 2020; Mills and Wiser, 2015). Both the generally lower prices and the cannibalisation effect have been perceived as problematic, because they lead to lower market revenues and would lead to less incentive to invest in new capacity in a free market (Hildmann et al., 2015; Joskow, 2008).

These empirical observations (Sensfuß, 2007; Sensfuß et al., 2008; Hildmann et al., 2015; Figueiredo and da Silva, 2018; Ozdemir et al., 2017; Hirth, 2018; López Prol et al., 2020; Mills and Wiser, 2015) were made in electricity systems where the existing conventional power generation fleet remained largely unchanged, i.e. in the short-term. While short-term effects are important, not least because they are presently faced by actors on the market, the long-term effects, i.e. the situation after the capacity mix has adjusted to an equilibrium state, set a limit on the *possible* role that VRE may play in the power system. For this reason, the long-term effects are the focus of this paper. Using computer models of the power market where investments in all generator capacities are optimised, it has been shown that even in a long-term

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equilibrium there is a decline in revenue for wind and solar with their penetration (Mills and Wiser, 2015; Lamont, 2008; Joskow, 2011; Kopp et al., 2012; Mills and Wiser, 2013; Hirth, 2013; Gilmore et al., 2015; Winkler et al., 2016; Gowrisankaran et al., 2016). The size of the effect was estimated to be a decrease in revenues by half at penetration levels of 15% for solar and 30% for wind in a selection of European countries (Hirth, 2013). The hypothesis put forward in these papers is that it is the variability of wind and solar that causes the decline (Lamont, 2008; Hirth, 2013; Winkler et al., 2016; Hirth and Radebach, 2016).

The idea that variability sets a ceiling for the cost-effective penetration level of VRE electricity has been influential. Blazquez (Blazquez et al., 2018) claims that 'The Paradox holds as long as market clear prices with short term marginal costs, and renewable technology's marginal cost is close to zero and not dispatchable', i.e. that energy-only markets with variable renewables inherently entail decreasing market value with penetration levels. Some have even suggested that the capacity factor (typically 10–25% for solar and 20–40% for onshore wind) should be considered as a limit on penetration (Trembath and Jenkins, 2015). Hirth and Radebach (Hirth and Radebach, 2016) conclude: 'Finally, and more fundamentally, it [the declining MV of VRE with penetration level] indicates that variable renewables face a substantial difficulty in becoming economical at high market shares. Without fundamental technological breakthroughs, a deep decarbonisation of power systems will be hard to achieve based on wind and solar power alone. Other supplementary low carbon technologies are likely to be needed.'

In apparent contradiction to the above-mentioned market integration studies, the last few years have also seen an increasing number of cost-minimising energy system studies with high shares (>80%) of variable renewables (Brown et al., 2018a; Hansen et al., 2019; Fripp, 2012; Haller et al., 2012; Budischak et al., 2013; Breyer et al., 2015; Bogdanov and Breyer, 2016; Frew et al., 2016; Schlachtberger et al., 2017; Brown et al., 2018b). The system solutions of these studies correspond to long-term equilibria where all generators, including VRE technologies, exactly cover their costs with their market revenue (the 'zero-profit rule', Boiteux, 1949; Boiteux, 1960). This appears to contradict market value studies that claim that wind and solar revenue will be pushed below the cost-recovery level at high penetrations.

We resolve this contradiction by showing in theory and in model simulations how cost, revenue and policy interact. We show that market value studies find declining market value by construction because they choose to force in VRE with support policies (be it quotas, feed-in tariffs, feed-in premiums or capacity incentives). If instead rising carbon dioxide (CO_2) taxes are used as the primary policy instrument to draw in wind and solar, then VRE revenue will always be sufficient to cover generation costs. We demonstrate that this holds in a power system model even at a penetration of solar and wind above 80%, which is much higher than is usually considered in the market value literature.

While the effects on market prices of subsidies for desirable goods versus taxes on undesirable goods is well understood (Pigou, 1920; Baumol, 1972), the effects on market values for different technologies in long-term electricity market equilibria has not been sufficiently considered in the literature. Many market value studies have considered the impact of fixed CO_2 taxes (Kopp et al., 2012; Mills and Wiser, 2013; Hirth, 2013; Gilmore et al., 2015; Winkler et al., 2016; Gowrisankaran et al., 2016; Hirth, 2015; Zipp, 2017), but CO_2 taxes have only ever been a subordinate policy to the main policy of VRE support. The resolution of the contradiction requires replacing VRE support with CO_2 reduction incentives. Although the purpose of a CO_2 tax is not explicitly to increase VRE generation, but instead to reduce CO_2 emissions up to the point where the marginal abatement cost is equal to the tax, it will have the indirect effect of drawing in VRE generators if they are the most cost-effective low-emission generators available in the system.

We show how the market value of variable renewables, and indeed any type of generator regardless of its variability, is contingent on the mechanism (policy instrument) by which it enters the long-term equilibrium solution. We also discuss how the previous literature on the subject has failed to highlight this fact, either by an implicit assumption on the policy instrument (Mills and Wiser, 2015; Kopp et al., 2012; Mills and Wiser, 2013; Hirth, 2013; Gilmore et al., 2015; Winkler et al., 2016; Gowrisankaran et al., 2016), by simultaneously changing several confounding factors (Hirth, 2013; Winkler et al., 2016) or by ignoring market value altogether (Frew et al., 2016; Schlachtberger et al., 2017; Reichenberg et al., 2018).

First we consider the economic theory (Sections 2 and 3) and then demonstrate the effects in a reimplementation of the energy system model EMMA used in (Hirth, 2013) in the PyPSA modelling framework (Brown et al., 2017) (Sections 4 and 5).

2. Introduction to theory

2.1. Zero-profit rule, market value and LCOE without policy measures

In a long-term equilibrium, where generator capacity is optimised along with power system operation, producers make zero profit under idealised conditions of perfect market competition, free entry and exit, linear cost functions and without any further constraints (Boiteux, 1949; Boiteux, 1960). If any producer makes a net profit, new producers will enter the market and competition will drive profits to zero; similarly if producers make a net loss, some will exit the market until losses are eliminated. For electricity markets, this *zero-profit condition* means in a long-term equilibrium that the average revenue that generators receive from the market exactly covers their costs.

The zero-profit condition can be restated per unit of generated energy in terms of the market value MV_s and levelised cost of electricity $LCOE_s$ of each generator s:

$$MV_s = LCOE_s \tag{1}$$

The market value is defined as the revenue averaged over each unit of energy sold. The LCOE is defined as the net present sum of all investment, fuel, operational and maintenance costs averaged over each unit of energy that is actually generated. While this definition of LCOE agrees with the usual definition for dispatchable generators, we differ from the standard definition for wind and solar by only averaging over the actual energy generated, rather than what theoretically would be available before curtailment. This definition raises the LCOE of wind and solar when there is curtailment at high penetrations. The equality (1) is proved for a general long-term equilibrium power model in Section 3.1.

Different generators have different market values because they occupy different niches in the optimal system, depending on their characteristics such as cost and variability. Each technology has its own optimal share of generation in the long-term equilibrium. To change that share, policy intervention is required. In this contribution we consider both support policies that force particular technologies into the system, as well as policies that force out polluting technologies.

2.2. Technology-specific support policies

Under 'support policy' we group all policies that encourage investment in a particular technology beyond the pure cost-optimum, either by mandating a certain share in the generation mix, or by creating a revenue stream independent of the electricity market. Examples of such policies include Renewable Energy Portfolio Standards (RPS) in various US states and Feed-in Tariffs (FiT) in Germany, which give a remuneration for every unit of energy generated from wind and solar.

The fact that an additional subsidy is required to achieve a higher share implies that the generator cannot make sufficient revenue from the market to cover its costs. The subsidy required to cover costs can be translated into an equivalent Feed-in Premium (FiP) $\mu_s > 0$ paid per unit of generated energy, thus modifying the zero-profit condition at equilibrium to

$$MV_s = LCOE_s - \mu_s \tag{2}$$

The FiP tops up the average revenue received by the generator from the market to the LCOE so that the generator covers its costs.

This relation holds regardless of the technology or support policy. If a technology is forced to cover a fixed share of demand, we show in Section 3.3 that μ_s is the shadow price of the corresponding constraint. If the share of generation available before curtailment is fixed instead of the actual generation (Hirth, 2013; Pahle et al., 2015), μ_s is proportional to the shadow price of the constraint (see Appendix B.1). If generators do not participate in the market at all, but are paid a Feed-in Tariff (FiT) to cover their costs at the same level as the LCOE, then μ_s is the difference between the average market value and the tariff.

Without a support policy, the system would settle into the equilibrium described in Section 2.1 with MV equal to LCOE for all technologies. A higher share of technology s requires a policy intervention. The higher the share, the higher the equivalent FiP μ_s needs to be, and thus the lower the market value drops according to Eq. (2).

The decline in market value is an indirect effect of the decline of market prices during the hours that the supported technology is generating. The exact mechanism is explained in more detail in the next section, but essentially the FiP μ_s paid per MWh reduces the effective marginal cost of technology s by μ_s, since it gets a revenue of μ_s from outside the market. The combined effect of having a larger share of technology s as well as technology s bidding into the market at a lower price serves to lower market prices when s is generating. This well-known fact that prices are surpressed by a surplus of some good is the essential result observed in the literature on the market value of renewables (Mills and Wiser, 2015; Kopp et al., 2012; Mills and Wiser, 2013; Hirth, 2013; Gilmore et al., 2015; Winkler et al., 2016; Gowrisankaran et al., 2016; Borenstein, 2008). Yet, these studies do not draw the conclusion that the MV decline is due to the surplus of VRE, but instead explain it by the variable nature of these sources.

The MV decline does not contradict the zero-profit condition, since the condition only applies to an undistorted equilibrium. We have departed from the equilibrium solution by forcing a share of a technology. The other technologies are still freely optimised, and are thus still subject to the zero-profit rule, although their share of total generation will be lower.

2.3. CO_2 policies

CO_2 policies include direct CO_2 taxes and CO_2 caps with traded certificates. They indirectly support wind, solar and other low-emission technologies by penalising high-emission generators.

Under CO_2 policies, the zero-profit rule still holds, but the relationship between revenue and costs now includes the equivalent CO_2 tax μ_{CO_2} (in euro per tonne of CO_2, €tCO_2^{-1}) and the technology-specific emission factor e_s (in tCO_2MWh^{-1})

$$MV_s = LCOE_s + e_s\mu_{CO_2} \tag{3}$$

This relation is proven in Section 3.4.

For technologies like wind, solar or nuclear with no direct emissions, we have exact cost recovery $MV_s = LCOE_s$. CO_2-emitting generators have to cover both generation costs and the CO_2 tax with their market revenue at equilibrium, and are thus pressured out of the market to the benefit of low-CO_2 generation.

CO_2 policies raise the market values of CO_2-emitting generation by raising their marginal costs, and thus raising prices at hours when they are generating.

2.4. Comparison of support and CO_2 policies

The effects of the two types of policy on prices and market values are strikingly different. Support policies depress market prices when the supported generators are running and offer them compensation outside of the market, whereas CO_2 policies raise market prices when fossil-fuelled generators are running, thus encouraging low-emission generators into the market. Support policies increase the share of low-emission technologies but reduce their average market revenue, whereas CO_2 policies increase their share while leaving their zero-profit condition intact. For fossil-fuelled generators, low-carbon support policies reduce their share of the market but do not affect their zero-profit condition, while CO_2 policies increase the overall costs they need to cover from the market, thus also reducing their share.

Fig. 1 provides an illustration of how the two policies impact dispatch, price and momentary revenue in a highly-simplified model with solar and three fossil technologies (lignite, hard coal and gas) over a period of 2 days (more elaborate simulations are provided in later sections). The solar support policy lowers prices both by the merit order effect when solar is feeding in and by turning prices negative when solar is price-setting (see the next section for a discussion of this mechanism; solar generation continues during this period because its feed-in is being subsidised outside of the market). Under the CO_2 policy, prices go to zero when solar is price-setting, but this is more than compensated by the rise in prices when the fossil-fuelled generators are price-setting.

These effects on prices affect the market value of solar. With no policy, there is sufficient revenue for solar to cover its costs. For the CO_2 policy this is also the case, since the area under the revenue curve is the same, but the hours when solar earns change: it earns less at midday, but more on the flanks of its generation profile. For the solar support policy, prices and revenue are lower at all times when it generates, so solar cannot cover its costs from the market.

Additional flexibility options such as transmission, demand response and storage alter the background system by allowing price arbitrage to smooth the variability of renewable generators (Hirth, 2013; Hirth, 2016; Tveten et al., 2016). By providing more demand in hours with low prices, flexibility helps to raise prices when renewables are abundant (Brown et al., 2019; Härtel and Korpås, 2021; Bernath et al., 2021; Böttger and Härtel, 2021; Ruhnau, 2020). When renewables are scarce and prices are high, flexibility lowers prices by providing more supply. More flexibility means that lower subsidies are required for VRE support policies to reach a given penetration level, while for CO_2 policies a lower CO_2 price is required for a given abatement level when flexibility is available.

3. Theory

In this section we use a long-term optimisation framework to show how prices and market values relate to costs and policy measures, and in particular under what circumstances the 'zero profit' rule holds. Proofs are provided for the equations stated in the previous section. The proof of the zero-profit condition with no additional policy measures goes back to Boiteux (1949); the discussion of profit under VRE support policies can also be found in Green and Léautier (2015). The optimisation problem setup and use of Karush-Kuhn-Tucker (KKT) conditions in the present contribution follows the textbook by Biggar and Hesamzadeh (2014).

3.1. Long-term equilibrium without policy measures

We maximise yearly social welfare for a single node with linear supply cost functions in a long-term equilibrium:

$$\max_{d_{a,t}, g_{s,t}, G_s} \left[\sum_{a,t} U_{a,t}(d_{a,t}) - \sum_s c_s G_s - \sum_{s,t} o_s g_{s,t} \right] \tag{4}$$

subject to

$$\sum_a d_{a,t} - \sum_s g_{s,t} = 0 \quad \perp \quad \lambda_t \quad \forall t \tag{5}$$

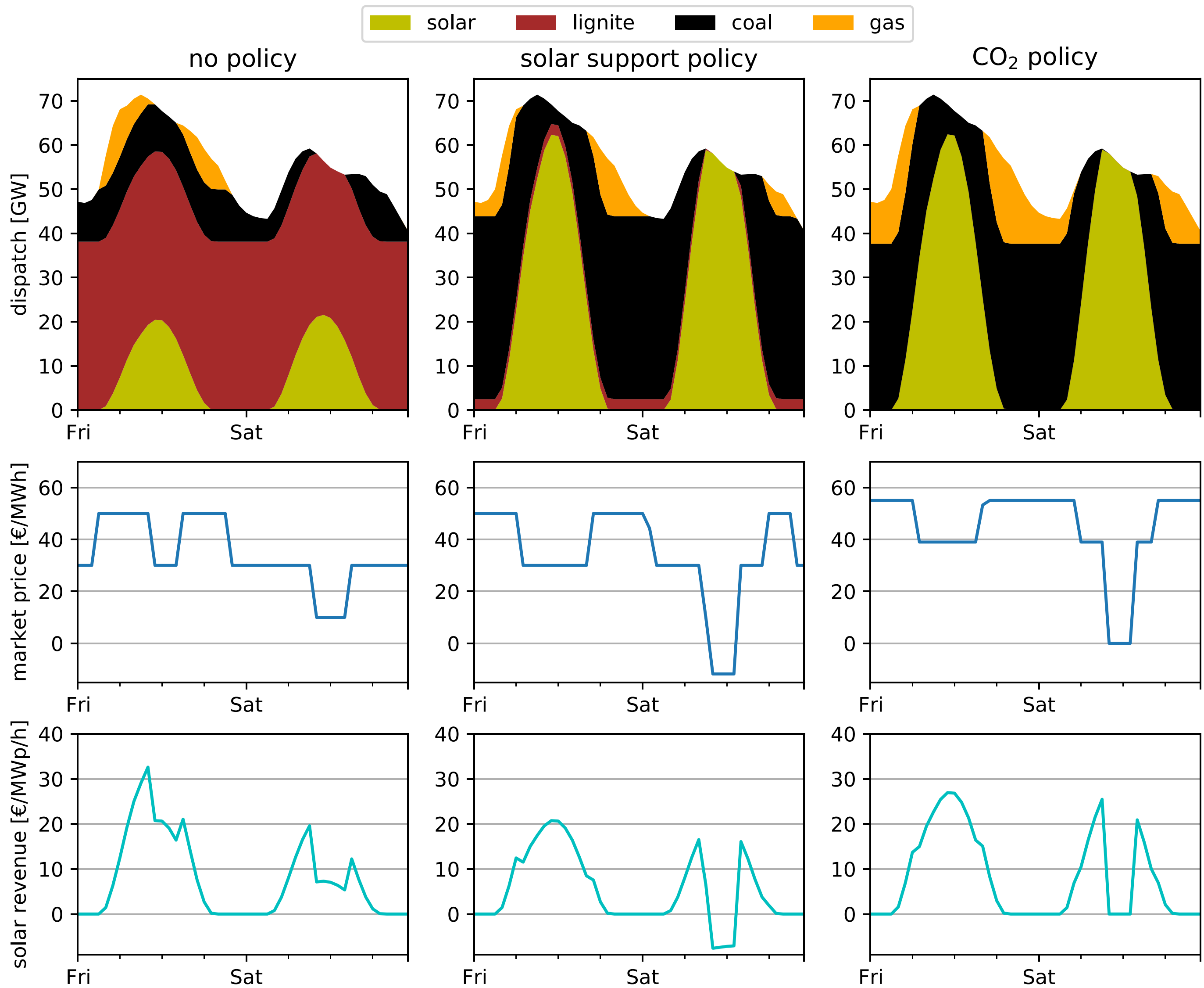

Fig. 1. Comparison of dispatch, market price and momentary solar revenue per unit of capacity in a highly-simplified long-term equilibrium model over 2 days with only four technologies (lignite, coal, gas and solar) and (a) no policy, (b) solar support policy and (c) CO_2 policy. The solar support and CO_2 policies are tuned to give the same penetration of solar.

$$-g_{s,t} \leq 0 \quad \perp \quad \underline{\mu}_{s,t} \quad \forall s,t \tag{6}$$

$$g_{s,t} - \overline{g}_{s,t} G_s \leq 0 \quad \perp \quad \overline{\mu}_{s,t} \quad \forall s,t \tag{7}$$

Here t labels time periods representing a year of load and weather conditions, a labels consumers, s labels generators, $d_{a,\,t}$ is the demand, $g_{s,\,t}$ is the generator dispatch, G_s is the generator capacity and $\overline{g}_{s,t} \in [0,1]$ is the availability/capacity factor (which varies with time for variable renewable generators like wind and solar). λ_t is the marginal price of electricity, while $\overline{\mu}_{s,t}$ and $_{s,\,t}$ represent shadow prices of the generator constraints. c_s represent the annualised investment and fixed operations and maintenance costs of the generators, while o_s represent variable costs. $U_{a,\,t}(d_{a,\,t})$ are the differentiable, concave utility functions of the consumers.

The KKT conditions are first-order conditions that are necessary for the optimal solution to satisfy. (Since in our case the objective function is concave and the constraints are affine, the conditions are also sufficient for optimality). The definition of the Lagrangian $\mathscr{L}$ and KKT conditions are provided in Appendix A. Conventions are chosen such that λ_t is positive if the price-setting generator has positive marginal costs, and such that all shadow prices μ are positive or zero.

From KKT stationarity we have for the variables representing the generator dispatch $g_{s,\,t}$ and capacity G_s:

$$\frac{\partial \mathscr{L}}{\partial g_{s,t}} = 0 \Rightarrow -o_s + \lambda_t + \underline{\mu}_{s,t} - \overline{\mu}_{s,t} = 0 \tag{8}$$

$$\frac{\partial \mathscr{L}}{\partial G_s} = 0 \Rightarrow -c_s + \sum_t \overline{g}_{s,t} \overline{\mu}_{s,t} = 0 \tag{9}$$

while for the inequalities (6) and (7) we get from KKT complementary slackness:

$$\underline{\mu}_{s,t} g_{s,t} = 0 \tag{10}$$

$$\overline{\mu}_{s,t} \left(\overline{g}_{s,t} G_s - g_{s,t} \right) = 0 \tag{11}$$

We will now show that each generator s exactly makes back their costs $c_s G_s + \sum_t o_s g_{s,\,t}$ from their market revenue $\sum_t \lambda_t g_{s,\,t}$, i.e. the 'zero-profit condition'.

$$
\begin{aligned}
c_sG_s+\sum_t o_s g_{s,t} &= \left(\sum_t \bar{g}_{s,t}\bar{\mu}_{s,t}\right)G_s+\sum_t\left(\lambda_t+\underline{\mu}_{s,t}-\bar{\mu}_{s,t}\right)g_{s,t} \\
&= \sum_t\left[\lambda_t g_{s,t}+\bar{\mu}_{s,t}\left(\bar{g}_{s,t}G_s-g_{s,t}\right)+\underline{\mu}_{s,t}g_{s,t}\right] \\
&= \sum_t \lambda_t g_{s,t}
\end{aligned} \tag{12}
$$

The first step substitutes the equations from KKT stationarity; in the second step terms are reorganised; in the final step the equations from KKT complementary slackness are applied.

We can use this, along with primal feasibility for the demand balancing constraint (5), to show that the total generator costs are equal to the total payments by consumers:

$$
\sum_s\left[c_sG_s+\sum_t o_s g_{s,t}\right]=\sum_{s,t}\lambda_t g_{s,t}=\sum_{a,t}\lambda_t d_{a,t} \tag{13}
$$

For a situation with perfectly price-inelastic demand where we can reduce the overall problem to generator cost minimisation, this is the statement of strong duality between the objectives of the primal and dual problems. Note, however, that unlike Eq. (13), Eq. (12) also holds at the level of individual generators.

3.2. LCOE, MV and RMV without policy measures

When both sides of (12) are divided by the generator's total dispatch we recover on the left the definition of the levelised cost of energy (LCOE) of the generator:

$$
LCOE_s \equiv \frac{c_sG_s+\sum_t o_s g_{s,t}}{\sum_t g_{s,t}} \tag{14}
$$

and on the right the definition of the market value (MV) of the generator, sometimes called the absolute market value (Hirth, 2013), which gives us the average revenue when the generator is producing:

$$
MV_s \equiv \frac{\sum_t g_{s,t}\lambda_t}{\sum_t g_{s,t}} \tag{15}
$$

The equality (12) then gives us:

$$
LCOE_s = MV_s \quad \forall s \tag{16}
$$

This is a restatement of the zero-profit rule on an averaged per-MWh basis.

The relative market value (RMV), also called the value factor in (Hirth, 2013), is the ratio of the market value to the load-weighted average market price:

$$
RMV_s \equiv MV_s\left(\frac{\sum_{a,t} d_{a,t}\lambda_t}{\sum_t d_{a,t}}\right)^{-1}=\frac{\left(\sum_t g_{s,t}\lambda_t\right)\left(\sum_{a,t} d_{a,t}\right)}{\left(\sum_t g_{s,t}\right)\left(\sum_{a,t} d_{a,t}\lambda_t\right)} \tag{17}
$$

Using the zero-profit rule (12) and the energy balance constraint (5) we can rewrite the RMV:

$$
RMV_s=\left(\frac{c_sG_s+\sum_t o_s g_{s,t}}{\sum_r c_rG_r+\sum_{r,t} o_r g_{r,t}}\right)\left(\frac{\sum_t g_{s,t}}{\sum_{a,t} d_{a,t}}\right)^{-1} \tag{18}
$$

From this it can be seen that in the absence of other constraints, the RMV is the ratio of a technology's share of total costs (first fraction) to its share of demand (second fraction). If a particular technology has a similar share of both energy provision and costs, then it will have an RMV close to unity.

3.3. Long-term equilibrium with support policy

If a subset of generators S is singled out and forced to provide a fixed amount of energy Γ during the year, this is represented with the constraint

$$
\sum_{s\in S,t} g_{s,t} \geq \Gamma \quad \perp \quad \mu_\Gamma \tag{19}
$$

For example, for a particular penetration of wind, S would represent all wind generators and Γ would be a fixed fraction of the annual demand.

For generators included in the constraint, $s \in S$, the stationarity Eq. (8) for $g_{s,\,t}$ from the previous section is altered to

$$
\frac{\partial\mathscr{L}}{\partial g_{s,t}}=0 \Rightarrow -o_s+\lambda_t+\underline{\mu}_{s,t}-\bar{\mu}_{s,t}+\mu_\Gamma=0 \tag{20}
$$

so that now for the generators in S

$$
c_sG_s+\sum_t o_s g_{s,t}=\sum_t g_{s,t}(\lambda_t+\mu_\Gamma) \quad \forall s\in S \tag{21}
$$

For generators excluded from the constraint, $s \notin S$, the zero-profit rule remains exactly the same as (12).

If (19) is not binding, then $\mu_\Gamma = 0$ and the zero-profit rule is recovered. In this case the given share is already part of the unconstrained optimum. However if (19) is binding, then more generation from S is being forced into the solution than the optimum without constraint (19), therefore $\mu_\Gamma > 0$ and generators in S can no longer recover their costs from the market prices λ_t alone. μ_Γ represents the per-MWh subsidy, or Feed-in Premium (FiP), required beyond the market price for generators in S to recover their costs.

Dividing by the total generation $\sum_t g_{s,\,t}$ we find for $s \in S$

$$
LCOE_s = MV_s + \mu_\Gamma \quad \forall s \in S \tag{22}
$$

For $s \notin S$ we have the regular no-profit rule

$$
LCOE_s = MV_s \quad \forall s \notin S \tag{23}
$$

Expressed another way: forcing in the penetration of a particular technology above its unconstrained optimal share depresses the market prices λ_t at the times when it is generating. This accounts for the 'market value' effect in long-term equilibrium models observed in (Hirth, 2013).

The prices found here can be reproduced by taking the optimal value of μ_Γ, removing the constraint (19) and making the substitution $o_s \to o_s - \mu_\Gamma$ for $s \in S$ to get a new, lower effective marginal cost, i.e. moving $\mu_\Gamma g_{s,\,t}$ to the left-hand side of (21) (see proof in Appendix B.6). The support policy thus depresses market prices by two mechanisms: when technology s is generating, the larger share of technology s pushes down prices even when technology s is not price-setting by pushing the supply curve to the right (the merit order effect); when technology s is price-setting, the subsidy reduces the bid o_s by μ_Γ and can even turn the market price negative if μ_Γ is larger than the marginal cost o_s. Negative bids are rational for generators if they are guaranteed the subsidy even when prices are negative. In reality, some markets suspend support for subsidised generators bidding in the market once market prices turn negative for a sufficient time (4 hours in the case of renewable energy in Germany built from 2021 (*Erneuerbare-Energien-Gesetz* 2021, 2021)), thereby removing the incentive for them to bid negative prices and thus mitigating this effect. In this case, examined in Appendix E.2, support policies still depress prices by the merit order effect.

3.4. Long-term equilibrium with CO_2 policy

If, rather than supporting particular technologies, we replace constraint (19) with a CO_2 cap K, the behaviour is different. Consider the CO_2 constraint:

$$\sum_{s,t} e_s g_{s,t} \leq K \quad \perp \quad \mu_{CO_2} \tag{24}$$

where e_s is the emission factor in tonne-CO_2 per MWh_{el} for generator s and K is a cap on yearly emissions in tonne-CO_2 per year. This constraint has the same form as (19), except for the direction of the inequality sign and the weighting of generation.

The stationarity Eq. (8) is altered to

$$\frac{\partial \mathscr{L}}{\partial g_{s,t}} = 0 \Rightarrow -o_s + \lambda_t + \underline{\mu}_{s,t} - \overline{\mu}_{s,t} - e_s \mu_{CO_2} = 0 \tag{25}$$

and now

$$c_s G_s + \sum_t o_s g_{s,t} = \sum_t g_{s,t}(\lambda_t - e_s \mu_{CO_2}) \quad \forall s \tag{26}$$

If the constraint (24) is binding, it pushes up market prices beyond the cost-recovery point so that charges for CO_2 emissions are also covered from the market.

Dividing by the total generation $\sum_t g_{s,t}$ we find

$$LCOE_s = MV_s - e_s \mu_{CO_2} \quad \forall s \in S \tag{27}$$

In this case, generators with no direct emissions, $e_s = 0$, continue to satisfy the zero-profit rule. Emitting generators with $e_s > 0$ have to cover the CO_2 price with their market revenues, but still recover their costs once the CO_2 levy has been paid.

The same prices can be obtained by replacing the CO_2 constraint with a direct cost of CO_2 and making the substitution $o_s \to o_s + e_s \mu_{CO_2}$, i.e. moving the term $e_s \mu_{CO_2} g_{s,t}$ to the left-hand side of (26). Through the higher effective operating costs for CO_2-emitting generators, the CO_2 price increases market prices when these generators are setting the price.

3.5. Other setups

Hybrid setups that combine CO_2 pricing and technology support are of course possible, and can be found in many of today's markets in Europe. A moderate CO_2 price tilts the equilibrium in favour of low-carbon technologies and reduces the feed-in premium needed for a given share of variable renewable energy, thus raising the market value. For a given penetration of wind and solar, a hybrid approach allows the market value of VRE to be set at any value between the two extremes of low MV with a support policy only, and MV equal to LCOE for the case that only a CO_2 policy is used to induce the share of VRE. Combining CO_2 pricing and technology support can reduce market distortions while limiting investor risk and thus their financing costs, as discussed in Section 6.2.

More complicated setups (forcing fixed shares for available rather than dispatched energy, limited installation potentials, multi-node networks, storage, convex generation costs) do not alter the conclusions reached for the simpler model above. Proofs for these setups can be found in Appendix B.

In addition, we show in Appendix B.7 that subsidising a set of technologies is exactly equivalent to taxing all other technologies when demand is perfectly price-inelastic. Switching from subsidy to tax just results in a constant lift to all the prices, and therefore a constant lift to all market values. Since a tax on non-VRE technologies is not a realistic policy proposal, we focus in the main text on CO_2 policies.

4. Power system model description

The theoretical insights developed above are demonstrated in a market model based on EMMA (Hirth, 2013) that has been reimplemented in the open PyPSA framework (Brown et al., 2017). The code for the model is available online under an open licence (Brown, 2020).

The model has five nodes for Germany and four of its neighbours: Poland, France, the Netherlands and Belgium. The model minimises long-term generation costs over historical hourly load and weather from the year 2010, assuming a perfectly price-inelastic demand up until a high value of lost load (1000 €/MWh). The model completely rebuilds the existing generation system ('greenfield investment') except for pumped hydro storage, for which existing capacities are taken assuming an energy storage capacity of 8 h at nominal power.

Generators are aggregated into a single representative class for each technology following (Hirth, 2013). The available variable renewable technologies are wind and solar power, while the dispatchable generators are coal, lignite, lignite with CCS, nuclear, open cycle gas turbines (OCGT) and combined cycle gas turbines (CCGT). We keep most of EMMA's cost and other technical assumptions, but update the nuclear cost from 4000 €/kW to 6000 €/kW, reflecting recent experience in Europe (Schröder et al., 2013), as well as reducing the wind cost from 1300 €/kW to 1040 €/kW and the solar cost from 2000 €/kW to 510 €/kW to reflect forecasts for 2030 made by the Danish Energy Agency in 2019 (*Technology Data for Generation of Electricity and District Heating*, 2019) (these assumptions are conservative given that some studies saw a cost of 460 €/kW for utility solar in Europe in 2019 (Vartiainen et al., 2020); with our assumptions the LCOE of wind and solar are still above the average reverse auction results in Germany in 2019). A table of technology assumptions can be found in Appendix C. In order to concentrate on the interaction of market policy and market prices, the wind and solar costs are fixed for the simulations and no learning effects are applied for high penetrations of wind and solar that might reduce costs. In addition, we remove the options for new nuclear and CCS when we focus on the penetration of variable renewable energy under different policies, so that we can achieve the full range of penetrations for the comparison; for the same reason we remove the options for solar, wind and CCS when we focus on nuclear penetration under different policies. Without these removals, each technology would only rise to its particular share in the cost-optimal mix of low carbon technologies for a given CO_2 policy; since this mix depends strongly on the model assumptions, and has been well studied in the literature (Verbruggen, 2008; Hamacher et al., 2013; Sepulveda et al., 2018; Kan et al., 2020), we avoid allowing the low-carbon technologies to compete in this study. The removal of the options for new nuclear and CCS for electricity generation can also be seen as representative of the policy environment in countries like Germany with regard to these technologies.

Transmission capacities between countries are fixed at the net transfer capacities (NTC) values from summer 2010. Following (Hirth, 2013) a discount rate of 7% is applied. To ensure that additional constraints do not distort the theoretical picture developed in the previous section, we do not model unit commitment or assume a baseload premium (whereby nuclear, coal and lignite run even if their variable cost is higher than the market price), nor do we model reserve requirements or revenue from reserve markets. To avoid interference with the CO_2 policy we introduce here, we also remove the CO_2 price of 20 €/tCO_2 assumed as a default in (Hirth, 2013).

In Appendix D we compare the results for the relative market value to the results from (Hirth, 2013), with and without the technology assumption changes. We find good agreement between the models.

To explore the impact of flexibility, in some scenarios we also allow the expansion of the transmission grid and the installation of new storage in the form of batteries and underground hydrogen storage (based on electrolysis of water and hydrogen turbines to feed back into the grid).

5. Simulation results

5.1. The market value of wind and solar depend on the policy measure

We contrast two main cases, one where VRE generation is driven by a constraint on minimum penetration level (*VRE support policy*) and another case where VRE generation is driven indirectly by a cap on CO_2

emissions (*CO_2 policy*), which makes fossil-fuelled generation more costly and thus draws VRE generation into the cost-minimal solution. Technically, the VRE support policy is implemented by a constraint in the optimisation model (Eq. (19)) that mandates a certain share of the demand be fulfilled by wind and solar. The CO_2 policy is implemented with a constraint on the maximum CO_2 emissions, which corresponds to a tax on CO_2-emitting generators (Eq. (24)).

The resulting market value (MV) at penetration levels for wind and solar between 0 and 70% for these two cases are shown in Fig. 2. The results for the VRE support policy case confirm what is widely seen in the literature (Mills and Wiser, 2015; Kopp et al., 2012; Mills and Wiser, 2013; Hirth, 2013; Gilmore et al., 2015; Winkler et al., 2016; Gowrisankaran et al., 2016; Borenstein, 2008): MV declines with rising penetration, eventually dropping to zero at a VRE penetration of 50%. The CO_2 policy shows a quite different trend: the MV dips slightly, then increases gently up to just over 80 €/MWh at 70% penetration.

This shows clearly that market value behaves differently depending on the policy used to reach a given level of wind and solar generation.

Now we expand upon the results for each policy in detail.

5.2. Market value with VRE support policy

Fig. 3 shows the behaviour of the MV, LCOE and Feed-in-Premium (FiP) μ_s[1] for the VRE support policy.

The LCOE remains approximately constant, dipping first and then rising gently. The dip occurs because of the changing mix of wind and solar, which have different LCOEs: first wind is preferred, which has a higher LCOE but a more regular profile, then solar increases, which has a lower LCOE, before wind takes over again at higher penetrations. The rise in LCOE reflects a preference for wind at higher penetrations, as well as curtailment which lowers the total generation in the denominator of the LCOE.

The FiP has to make up the difference between the MV and LCOE, and thus rises accordingly. The FiP is always positive because the equilibrium solution without the VRE support policy does not contain wind and solar (since the cost of generation from fossil fuels is so low in the model). The MV can reach zero and even become negative, since the FiP can force market prices to be negative in some hours; simulations where negative prices are forbidden are presented in Appendix E.2.

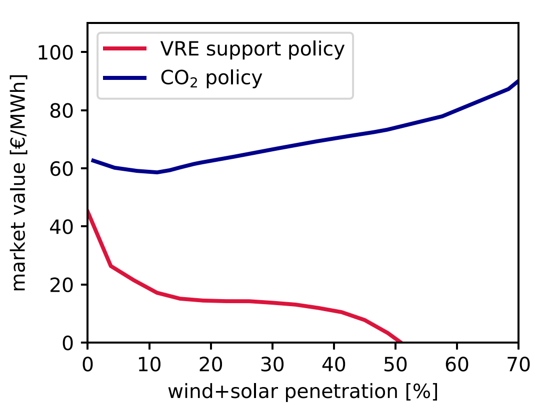

Fig. 2. Comparison of the market value of wind and solar as their combined penetration is mandated using (i) a VRE support policy and (ii) a CO_2 policy.

[1] As outlined in Section 3.3, the Feed-in-Premium (FiP) μ_s is the dual, or shadow price, of the VRE constraint (19).

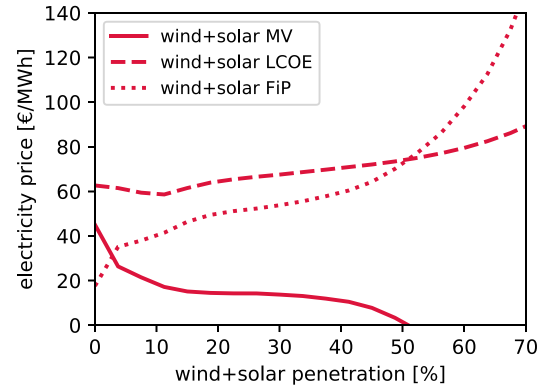

Fig. 3. Market quantities under a VRE support policy as the penetration of wind and solar energy covering electricity demand is increased. In this case there is no additional flexibility from storage or transmission reinforcement.

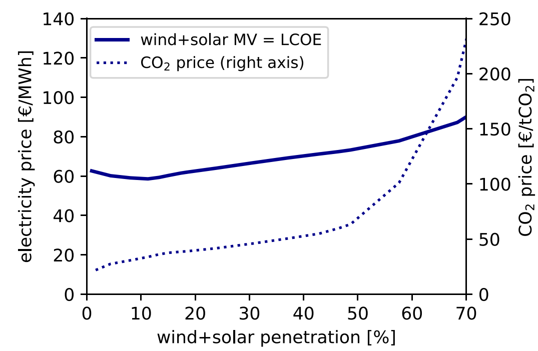

Fig. 4. Market quantities under a CO_2 policy as the average CO_2 emission factor is reduced, forcing up the wind and solar penetration.

5.3. Market value with CO_2 policy

Fig. 4 shows the MV, LCOE and CO_2 tax μ_{CO_2} for the CO_2 policy.[2]

Since wind and solar have no direct CO_2 emissions, by Eq. (3) the LCOE is exactly equal to the MV. The dip and gentle rise of LCOE has the same explanation as for the VRE support policy (see Appendix Fig. E.20 for the changing shares of wind and solar).

The CO_2 price required to induce a given VRE penetration rises to 70 €/tCO_2 at a penetration of 50%, before rapidly rising to above 220 €/tCO_2 at 70%. 70 €/tCO_2 is more than the 55 €/tCO_2 peak seen in early 2021 for CO_2 certificate prices in the European Union Emissions Trading System (ETS), but is less than the 129 €/tCO_2 price expected in 2030 in order to reach the targets of the European Green Deal (Pietzcker et al., 2021), and considerably less than the 195 €/tCO_2 damages due to climate change estimated in 2020 with a 1% rate of time preference by the German Environment Agency (*Methodenkonvention 3.1 zur Ermittlung von Umweltkosten: Kostensätze*, 2020). Until 50% penetration the behaviour of the system under a CO_2 policy only requires moderate changes. Beyond 50%, the lack of additional flexibility options makes CO_2 mitigation more expensive.

5.4. System cost and market price

Fig. 5 compares the rising average system generation cost for the two policies, including all capital and marginal costs but excluding subsidies and the CO_2 price. The costs rise at a similar rate with VRE penetration, implying that both policies achieve similar effects. Costs are slightly

[2] As outlined in Section 3.4, the CO_2 tax μ_{CO_2} is the dual, or shadow price, of the CO_2 constraint (24).

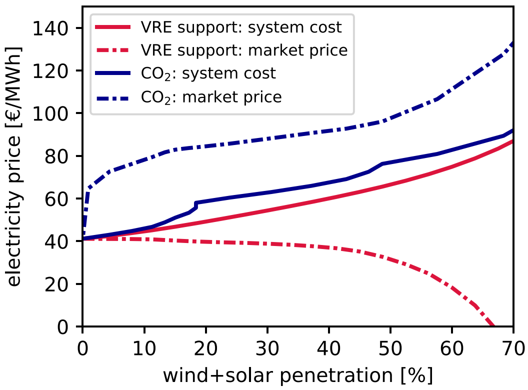

Fig. 5. Comparison of average system generation cost (excluding CO_2 price) and average market price for the VRE support and CO_2 policies without flexibility.

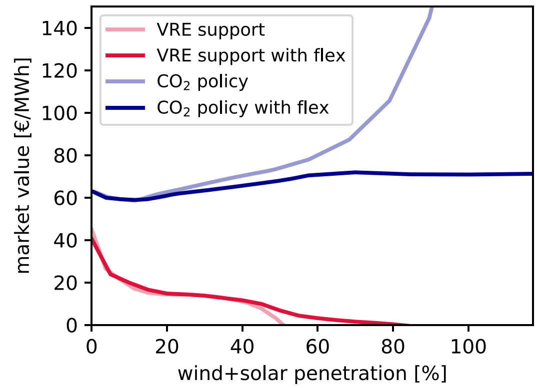

Fig. 6. Market value under VRE support and CO_2 policies as wind and solar penetrations rise, for scenarios with and without additional flexibility from transmission and storage. The penetration of VRE as a fraction of demand goes beyond 100% to 117% because VRE must also cover storage losses.

higher with a CO_2 policy because increasing wind and solar penetration is not the only cost-effective measure to reduce CO_2 emissions: switching from lignite and coal to natural gas is prioritised before VRE capacity at some penetrations. These measures make the system more expensive than the VRE support policy case for a given VRE penetration. (If we compare the policies based on CO_2 emissions, then the CO_2 policy is naturally more efficient at reducing emissions, see Appendix Fig. E.26.)

Fig. 5 also shows how the load-weighted average electricity price changes with penetration for each policy. For the VRE support policy, prices are depressed by the merit order effect when VRE generate and by negative prices when VRE are price-setting, as discussed in Section 3.3. For the CO_2 policy the merit order effect of VRE generation is counteracted by the increasing cost of fossil-fuelled generation, pushing up prices when these generators are price-setting (see Section 3.4).[3]

For the VRE support policy, consumers pay less than the generation cost, since the difference between the average market price and the generation cost is accounted for by the external subsidies paid to VRE generation. For the CO_2 policy, consumers pay more than the generation cost, since they must also pay for CO_2 emissions according to the prevailing CO_2 price. Both the costs of the VRE subsidies and the revenues from the CO_2 tax can be passed on to consumers, so that consumers only pay the average system cost in the end, thereby evening out the difference between the policy regimes from the consumers' perspective.[4]

5.5. *Including transmission and storage flexibility*

If additional flexibility options are made available to the investment optimisation, the market value under a CO_2 policy remains regular all the way up to full VRE penetration. Flexibility in this case includes the option to build new transmission capacity between the countries, as well as the availability of both battery storage and hydrogen storage. The results for MV of VRE with and without flexibility are shown in Fig. 6. Without flexibility, the MV increases strongly above 70% because of high curtailment that depresses the LCOE. High curtailment reflects the mismatch between VRE and demand profiles. With flexibility, the MV rises slowly before plateauing at around 71 €/MWh. When VRE covers all of the demand and storage losses, the average total system cost is higher at 114 €/MWh, reflecting the cost of additional flexibility options, in this case primarily the hydrogen storage. The CO_2 price rises from 55 €/tCO_2 at 50% to 165 €/tCO_2 at 100% penetration (less than the climate damages of 195 €/tCO_2 estimated in 2020 with a 1% rate of time preference in (*Methodenkonvention 3.1 zur Ermittlung von Umweltkosten: Kostensätze*, 2020)).

The breakdown of system cost by component in Fig. 7 shows the substitution of technologies as the CO_2 limit is tightened. Hydrogen storage is critical for removing the final emissions from the system, since hydrogen stored underground can provide power when wind and solar feed-in is low for multiple days. The fact that wind and solar dominate system costs at the same time as dominating energy generation guarantees a relative market value (RMV) close to unity according to Eq. (18). Even at full VRE penetration, the RMV of wind and solar only drops to 0.62, see Appendix Fig. E.25. Similar results have also been shown in models coupled to building heating and transport, where demand response from electric vehicles and heat pumps, as well as cheap storage of heat, hydrogen and methane, help to support prices using price arbitrage and keep the RMV close to unity (Brown et al., 2019; Härtel and Korpås, 2021; Bernath et al., 2021; Böttger and Härtel, 2021; Ruhnau, 2020). Flexible demand and storage bid up prices by providing extra demand when VRE are abundant, and lower prices by reducing demand when VRE are scarce.

It is sometimes assumed that prices become singular in a system based entirely on wind and solar, alternating between zero during VRE abundance and very high levels during VRE scarcity. In Appendix E.6 we show that this is not the case by looking at the price duration curves in the system. As fossil-fuelled generation is pushed out of the system,

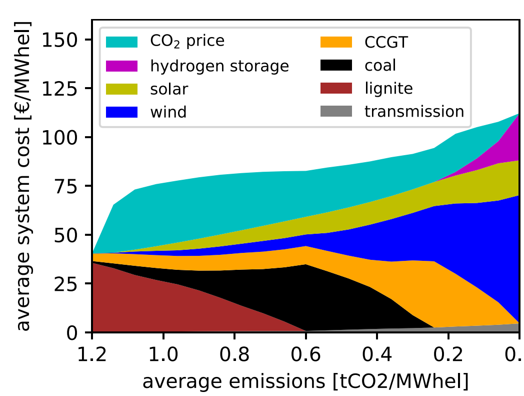

Fig. 7. Breakdown of average system cost (total cost divided by total load) under a CO_2 policy as the CO_2 budget is tightened, for a scenario with transmission expansion as well as short- and long-term storage. The average system cost, including the CO_2 price, is equal to the load-weighted average market price by Eq. (13).

[3] If the CO_2 policy is replaced by a tax on non-VRE generation, the system costs will be identical and the market prices are lifted by a constant factor, as discussed in Appendix B.7. In this case the effect of the CO_2 policy is similar because the non-VRE generators all emit CO_2, albeit at different rates.

[4] This is only true for the model setup of perfectly price-inelastic demand; the difference would be more significant with elastic demand.

storage and transmission arbitrage start to set the prices, removing singular prices with demand bids when VRE is abundant and supply bids when VRE is scarce. The distribution of hours per year in which wind and solar recoup their costs barely changes as the CO_2 budget is lowered.

5.6. Support versus CO_2 policies for nuclear power

While we have focused on wind and solar generation, reflecting the focus of the literature on market value, exactly the same considerations apply in the case of non-variable low-emissions technologies like nuclear.

Fig. 8 shows the behaviour of nuclear's market value under a nuclear support policy and under a CO_2 policy. As described in Section 4, we have removed the options to build wind, solar and CCS so that we can focus on nuclear penetration versus fossil-fuelled generation. It is assumed that nuclear can be built to operate flexibly (Jenkins et al., 2018).

With a technology-specific support policy pushing a fixed share of nuclear power, the market value of 34 €/MWh at low penetrations is much lower than the LCOE of 74 €/MWh, implying that it requires a subsidy of 40 €/MWh to compete with the other baseload power source in the system, lignite. The support policy has pushed nuclear's market value below the point of cost recovery, causing it to cannibalise its own revenue. At higher penetrations the market value drops all the way to zero, since the cost characteristics of nuclear are not suitable to match the full variability of the demand. For nuclear it is the variability of demand, rather than of supply in the case of VRE, that combines with the support policy to push the market value to zero due to the mismatch of the supply and demand profiles.

With a CO_2 policy drawing nuclear into the system, the market value matches the LCOE, so that nuclear exactly makes back its costs from the market. The LCOE rises at higher penetrations as the capacity factor of nuclear drops to match the variable demand. Initially a CO_2 price of 34 €/tCO_2 is necessary for nuclear to displace lignite and reach a share of 68% of electricity generation. To reach 90% penetration, the CO_2 price must rise to 69 €/tCO_2, and even higher for higher penetrations (see Appendix Fig. E.24).

Both the cannibalisation effects and the drop in market value with penetration under a support policy, as well as the fundamentally different behaviour under support versus CO_2 policy regimes, follow the same pattern as the case of VRE technologies (compare Figs. 6 and 8). This was to be expected, given that the theoretical considerations in previous sections are technology-neutral. The decline of market value under a support policy happens for all technologies regardless of their variability or other techno-economic characteristics, and is thus primarily a policy-dependent phenomenon. The only difference between dispatchable and variable technologies is that this decline happens faster for VRE because they do not match the shape of the variable demand as well as dispatchable technologies, making the impact of variability on market value only a secondary effect to policy, since it affects the rate of change rather than the direction.

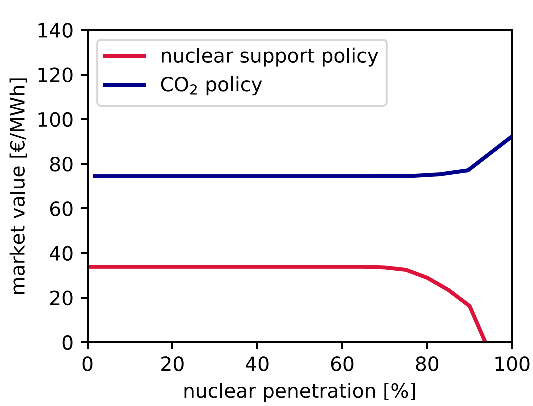

Fig. 8. Comparison of the market value of nuclear as its penetration is mandated using (i) a nuclear support policy and (ii) a CO_2 policy.

6. Discussion

6.1. The mechanisms underlying MV decline

This paper contrasts the impact of support and CO_2 policies on the market value (MV) of wind and solar. We find that the MV of wind and solar decreases strongly under VRE support policies, whereas under CO_2 policies the MV remains high enough for wind and solar to cover their costs from the market. Thus, the declining MV of VRE that has been observed in previous literature (Mills and Wiser, 2015; Kopp et al., 2012; Hirth, 2013; Winkler et al., 2016; Hirth and Radebach, 2016; Blazquez et al., 2018) is caused primarily by the implicit assumption of policy regime, and not, as has been claimed before (Hirth, 2013; Blazquez et al., 2018), by the variability of wind and solar, although the variability can contribute towards the speed of decline.

Many of the papers on market value in long-term equilibrium models achieve rising shares of wind and solar either by exogenously fixing the capacity of wind and solar (Mills and Wiser, 2015; Kopp et al., 2012; Mills and Wiser, 2013; Gilmore et al., 2015; Gowrisankaran et al., 2016; Borenstein, 2008) or by forcing them into the system with a constraint (Hirth, 2013; Winkler et al., 2016; Hirth, 2015; Pahle et al., 2015; Hirth, 2016; Hirth and Müller, 2016),[5] without always making clear that forcing a share of wind and solar is equivalent to a VRE support policy. For example, Hirth (2013) claims to 'identify and quantify the impact of prices and policies on the market value of VRE', but the policies do not include FiTs or renewable portfolio standards. Such policies are, however, implicit in the study design since it increases the penetration level beyond the equilibrium share, which would never come about without technology-specific policies.[6] Therefore, their conclusions that 'the market value of both wind and solar power is significantly reduced by increasing the market shares of the respective technology' is not universally true, but only under the assumption that the market shares are increased using a technology-specific support mechanism. The paper by Winkler et al. (2016) has a similar set-up, where the increase in penetration level, i.e. the implicit technology support policy, is part of the study design, yet not recognised as a policy.

Much of the literature has viewed a CO_2 price as only one among many other mechanisms by which the MV decline can be mitigated under a VRE support policy regime (Kopp et al., 2012; Mills and Wiser, 2013; Hirth, 2013; Gilmore et al., 2015; Winkler et al., 2016; Gowrisankaran et al., 2016; Hirth, 2015; Zipp, 2017). Since these papers leave the CO_2 price fixed, they still observe a declining market value as the subsidy for VRE is increased, even with a high CO_2 price of 100 €/tCO_2 and the removal of nuclear and CCS (Hirth, 2013; Hirth, 2015). In contrast, we replace the subsidy with a rising CO_2 price as the primary mechanism to draw in wind and solar, thus guaranteeing that there is no decline in market value at all.

A policy regime of subsidy for a particular technology will drive down its market value regardless of its variability, location, fuel cost or the rest of the generation mix. Studies that demonstrate declining market value are simply reproducing this basic point, except that they

[5] Note that Lamont (Lamont, 2008) does not follow this approach, but draws in wind and solar by reducing their capital costs, thereby simulating the effects of technological learning and guaranteeing that costs are covered from the market.

[6] Consider what would happen in the long-term equilibrium without any policy intervention: there would be no market value decline, since the technology would settle at its optimal long-term share with MV = LCOE, a share based on its variability, costs and the rest of the generation mix. It takes policy to distort this equilibrium, thereby altering the share and the market values.

obscure the nature of the subsidy by including it only implicitly as a constraint that forces in the technology share. Our contribution is to explain the mechanism by which this constraint acts as a subsidy to depress prices, showing it both in theory and in simulations. In addition, we also show that there is nothing particular about variable generators with respect to market decline with increased forced share. This also happens to nuclear, see Fig. 8. It is the fact that a technology is forced beyond its equilibrium share that causes the decline: the particular techno-economic properties of the technology (variability, ratio of CAPEX to OPEX) and the rest of the mix (the other available technologies and their properties) only affect the speed of decline. A CO_2 policy that draws in wind and solar with a rising CO2 tax causes no decline, see Fig. 4. This is true for wind, solar and other low-CO_2 technologies like nuclear, see Fig. 8.[7] The variability is only a secondary characteristic that affects the *rate* of decline of MV under support policies, which is faster for VRE than for nuclear. We thereby demonstrate that the policy mix is the primary mechanism affecting market value (since it affects the fundamental direction of market value change), while variability, fuel cost and generation mix only affect the rate of change of market value in the policy regime.

We grant a whole host of strategies, which can be collectively labelled ‘flexibility measures’,[8] as having the potential to *dampen* the MV decline under a VRE support policy, yet not solving the bigger issue of the ‘cannibalisation effect’ (Hogan, 2017), which applies as much for VRE as for nuclear if they are subsidised.

6.2. Policy implications

The main policy implication is that policy makers should not see market value decline under VRE support policies as an indication that variable renewable energy is hitting fundamental integration limits. Thus we oppose the notion expressed e.g. in Hirth and Radebach (2016), where they claim that: ‘variable renewables face a substantial difficulty in becoming economical at high market shares. Without fundamental technological breakthroughs, a deep decarbonisation of power systems will be hard to achieve based on wind and solar power alone. Other supplementary low carbon technologies are likely to be needed.’

MV decline is a result of policy choices rather than an intrinsic property of VRE. In particular, it is a result of choosing not to value the low CO_2 emissions of wind and solar inside the market, but to subsidise VRE outside of the market. The strong dependence of market value on the policy regime (and on the rest of the system composition) means that market value should be used with a keen awareness of its limitations. Just as the LCOE metric does not provide a complete picture of the cost performance of technologies (Mai et al., 2021), market value should be used in concert with other metrics when comparing technologies, such as the effect on total system cost.

This paper focuses on the effects of policy on market value rather than on the desirability of the policy measures themselves.[9] While a CO_2 policy may be more efficient to reduce CO_2 emissions in theory, there are many situations where VRE support policies are preferable to CO_2 policies, such as when encouraging research, development and deployment to lower costs through learning, reducing investor risk, or because in some regions subsidies enjoy more political support than taxes. In these cases the measure of successful integration should be the total cost of the system rather than market value, since the system cost can be calculated regardless of the market structure. Comparison to the economically efficient solution with a CO_2 policy may also provide useful guidance.[10]

In particular the impact on financial risk, and thus investor behaviour, may differ substantially between support and CO_2 policies: CO_2 policies send a market signal to encourage low-emission generation, whereas one of the main purposes of support policies is to provide investor certainty for capital-intensive investments that might otherwise be subject to market risks from fluctuating electricity and CO_2 prices (Hiroux and Saguan, 2010; Held et al., 2019). Lower risk means lower financing costs, which feeds through to a lower LCOE and a lower system cost (Schmidt et al., 2019; Egli et al., 2019; Butler and Neuhoff, 2008). A hybrid policy framework can provide both of these benefits: a CO_2 price to support low-emission generation, and a guaranteed per-kWh feed-in premium for VRE generation. If the CO_2 price is sufficiently high, then the feed-in premium for a given share of VRE, μ_Γ in Eq. (1), can be close to zero. This provides minimal market distortion, costs consumers very little, but reduces investor risk and thus lowers financing costs.

6.3. Negative prices

Under the VRE support policy, electricity prices may become negative because it is rational for VRE generators to offer negative bids, since they are subsidised for their feed-in regardless of the market price. VRE generators have an effective bid of their running cost minus a feed-in premium equivalent to the shadow cost of the VRE-constraint, as discussed in Section 3.3.[11] A similar construct was used and negative prices were observed in (Pahle et al., 2015; Green and Léautier, 2015). In setups where the available energy rather than the dispatched energy is constrained (Hirth, 2013) VRE support does not cause negative prices because the constraint is equivalent to subsidising the capacity rather than the energy generation, see Appendix B.1.

In reality, some countries have policies that withdraw subsidies when prices go negative for a sufficient time (4 hours in the case of Germany for generators built from 2021 (*Erneuerbare-Energien-Gesetz* 2021, 2021)). Under such policy regimes, it would be rational for the producer never to bid in less than its running costs to the market, and thus the market prices would be higher. Results for support policies where negative prices are forbidden are provided in Appendix E.2. Under the VRE support policy the market values still decline well below the cost recovery point with increasing VRE penetration, but do so more slowly and do not turn negative.

6.4. MV under different policies in reality: the example of Germany

It is undisputed that the revenues from sales on the market for VRE generators have decreased in the real world, which has been shown in several studies on historical data for electricity prices (Sensfuß, 2007; Sensfuß et al., 2008; Hildmann et al., 2015; Figueiredo and da Silva, 2018; Ozdemir et al., 2017; Hirth, 2018; López Prol et al., 2020; Mills and Wiser, 2015; Hirth, 2013). While this is partly due to short-term effects as the rest of the system takes time to reach a new equilibrium with VRE, it also reflects policy choices. In Germany, subsidies were used to increase the share of VRE in electricity to around 26% in 2018. The average power price and market values of wind and solar fell from 2011 to 2016, as can be seen in Fig. 9. This is an effect of the FiT policy

[7] Remember from Section 4 that in the CO_2 policy simulations, other low-carbon technologies were removed to achieve the full range of penetrations. With competing technologies, cost-recovery from the market under a CO_2 policy still applies for a mix of technologies following the theory in Section 3.

[8] These have been individually investigated in previous literature and may be DSM measures (Winkler et al., 2016; Pahle et al., 2015), storage (Hirth, 2013), hydro power (Hirth, 2016; Tveten et al., 2016; Obersteiner and Saguan, 2010) or transmission extensions (Hirth, 2013; Obersteiner and Saguan, 2010).

[9] For such an investigation, more sophisticated methods, which account for a broader technology selection, demand elasticity, inter-temporal dynamics, learning effects, path dependencies (Grubb et al., 2021), risk averse agents and political economy aspects would be necessary.

[10] In the model setup in this paper the system costs for each policy for a given level of CO_2 emissions are quite close, see Appendix Fig. E.26.

[11] Note that this cause of negative prices is distinct from other causes, such as unit commitment or network constraints.

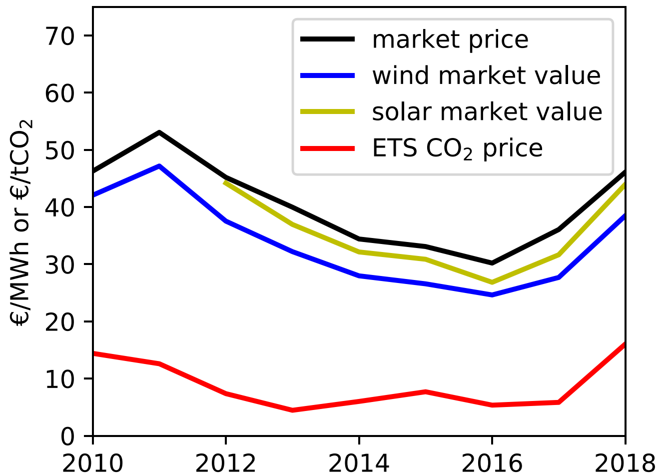

Fig. 9. Market data from Germany, 2010–2018. As the CO_2 price rose towards the end of the period, so have the average market price and market values of wind and solar. Data from (Open Power System Data, 2019). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

regime (which is a VRE support policy) combined with falling fuel prices. However, from 2016 onwards, prices increase again, with market values approaching current German LCOEs for wind and solar. This has been attributed to an increasing CO_2 price on the EU Emissions Trading System (ETS) market (a CO_2 policy) (*Die Energiewende im Stromsektor: Stand der Dinge* 2018, 2019). Thus the German prices (Fig. 9) may be interpreted as a supporting argument for our evaluation of the effect when VRE support policies dominate (up until 2016) and when CO_2 policies have a strong effect (after 2016).

6.5. Limitations of this study

In this study we have focused on the mechanisms connecting cost, price and policy in the long-term. The theory holds regardless of any specific technology assumptions, but many of the simulation results depend on the background system choices we have made. The base model excludes new nuclear, CCS, price-elastic demand, demand-side management (DSM), coupling to transport or heating, hydroelectric dams and interconnection across the whole of Europe. A larger geographic scope or the inclusion of hydroelectric dams, DSM or sector coupling would expand the flexibility mechanisms and thereby dampen the decrease of MV under VRE support policies and decrease system cost (Brown et al., 2018b; Brown et al., 2019). New nuclear or CCS could compete with VRE under a CO_2 policy and limit the ultimate VRE penetration, depending on the costs, but they would not affect the conclusions on market value. The approach of grouping generators into representative classes for each technology, which we took over from (Hirth, 2013), is standard practice in long-term equilibrium modelling but leads to a strongly simplified step-wise merit order curve compared to the smoother curve that would arise from a wide variety of generator types. This does not affect our theoretical results for the long-term equilibrium, but may impact the rate of market value decline in a more realistic short-term model.

7. Conclusions

The market value of wind and solar (VRE) depends strongly on the policies used to promote them. Previous studies have implicitly assumed that direct subsidies are used to force VRE penetration, which have the effect of depressing both their market value and overall market prices. If instead a CO_2 price is used to draw in low-emission generation, market values of generators in long-term equilibria are guaranteed to cover the generators' costs. Market values remain stable even at VRE penetrations approaching 100%, as long as sufficient flexibility from transmission and storage is available in the system.

This means that declining market value under support policies, such as Feed-in-Tariffs or Renewable Portfolio Standards, does not necessarily indicate problems with the market integration of VRE. Declining market value is a side-effect of choosing a technology support policy, rather than creating value in the market for technologies with low CO_2 emissions. A better measure of market integration is the total system cost, since it can be calculated regardless of the market structure.

By showing the strong dependence of market value on policy choice, we have thus resolved the apparent contradiction between the literature showing market value decline with penetration under support policies, and the literature showing that high penetrations of VRE can be cost-effective under CO_2 policies.

Declaration of Competing Interest

None.

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Appendix A. Karush-Kuhn-Tucker (KKT) conditions

In this section we set the signs and notation for the Karush-Kuhn-Tucker (KKT) conditions.

We have an objective function over variables labelled by l:

$$\max_{x_l} f(x_l) \tag{A.1}$$

subject to equality (i) and inequality (j) constraints:

$$g_i(x_l) = 0 \quad \perp \quad \lambda_i \tag{A.2}$$

$$h_j(x_l) \leq 0 \quad \perp \quad \mu_j \tag{A.3}$$

We build the KKT Lagrangian:

$$\mathscr{L}(x_l, \lambda_i, \mu_j) = f(x_l) - \sum_i \lambda_i g_i(x_l) - \sum_j \mu_j h_j(x_l) \tag{A.4}$$

The KKT conditions are equations satisfied by x_l, λ_i and μ_j at the optimum point.

First we have stationarity:

$$0 = \frac{\partial \mathscr{L}}{\partial x_l} = \frac{\partial f}{\partial x_l} - \sum_i \lambda_i \frac{\partial g_i}{\partial x_l} - \sum_j \mu_j \frac{\partial h_j}{\partial x_l} \tag{A.5}$$

then primal feasibility:

$$g_i(x_l) = 0 \tag{A.6}$$

$$h_j(x_l) \leq 0 \tag{A.7}$$

then dual feasibility:

$$\mu_j \geq 0 \tag{A.8}$$

and finally complementary slackness:

$$\mu_j h_j(x_l) = 0 \tag{A.9}$$

(i.e. either $\mu_j = 0$ or the inequality constraint is binding $h_j(x_l) = 0$).

Appendix B. Further proofs

B.1. Single node long-term equilibrium with VRE support policy for available power

If we add a constraint for a subset S of generators based on the available power before curtailment, as is done in (Hirth, 2013), rather than the actual dispatched power

$$-\sum_{s\in S,t} \overline{g}_{s,t} G_s \leq -\Theta \quad \perp \quad \mu_\Theta \tag{B.1}$$

($\overline{g}_{s,t}$ is the hourly capacity factor for generator s at time t) then this alters the stationarity Eq. (9) for G_s to

$$\frac{\partial \mathscr{L}}{\partial G_s} = 0 \Rightarrow -c_s + \sum_t \overline{g}_{s,t} \overline{\mu}_{s,t} + \sum_t \overline{g}_{s,t} \mu_\Theta = 0 \tag{B.2}$$

so that now for renewable generators

$$c_s G_s + \sum_t o_s g_{s,t} = \sum_t \lambda_t g_{s,t} + \mu_\Theta G_s \sum_t \overline{g}_{s,t} \tag{B.3}$$

If there is no curtailment, $\overline{g}_{s,t} G_s = g_{s,t}$ and this becomes the same expression as (21).

Since μ_Θ multiplies the capacity G_s, this can be interpreted as a subsidy for capacity. (In Section 3.3 we fixed the share of dispatched generation instead, so there it was a subsidy on dispatch.) This means the effective marginal cost is not affected and does not go negative. This makes sense because if capacity is subsidised, generators have no incentive to feed in when prices are negative. Instead, they curtail the available energy.

Dividing (B.3) by the total generation $\sum_t g_{s,t}$ we find for $s \in S$

$$LCOE_s = MV_s + \mu_\Theta \frac{G_s \sum_t \overline{g}_{s,t}}{\sum_t g_{s,t}} \quad \forall s \in S \tag{B.4}$$

For $s \notin S$ we have the regular no-profit rule

$$LCOE_s = MV_s \quad \forall s \notin S \tag{B.5}$$

B.2. Single node long-term equilibrium with limited installation potentials

If there are limits on installable potentials for generators

$$G_s \leq G_s^{max} \perp \mu_s^{max} \tag{B.6}$$

then we get

$$\frac{\partial \mathscr{L}}{\partial G_s} = 0 \Rightarrow c_s - \sum_t \overline{\mu}_{s,t} + \mu_s^{max} = 0 \tag{B.7}$$

and now

$$c_s G_s + \sum_t o_s g_{s,t} = \sum_t \lambda_t g_{s,t} - \sum_s \mu_s^{max} G_s \tag{B.8}$$

We have effectively added to the capital cost c_s a cost related to the scarcity of the potential for G_s, which drives up the cost. Because the resource is scarce, generators can claim extra revenue for this scarcity, i.e. because there is no alternative, there is extra profit to be obtained from the market.

B.3. Single node long-term equilibrium with storage

Suppose we add storage units r with discharging dispatch $g_{r,t}^{\text{dis}}$ and power capacity G_r^{dis}, storing power $g_{r,t}^{\text{sto}}$ and capacity G_r^{sto}, and state of charge $g_{r,t}^{\text{ene}}$ and energy capacity G_r^{ene}. The efficiency from hour to hour is η_r^{ene} (for losses due to self-discharge), the storing efficiency is η_r^{sto} and the dispatch efficiency is η_r^{dis}.

We add to the objective function an additional cost term:

$$-\sum_{r,\circ} c_r^\circ G_r^\circ = -\sum_r c_r^{\text{ene}} G_r^{\text{ene}} - \sum_r c_r^{\text{sto}} G_r^{\text{sto}} - \sum_r c_r^{\text{dis}} G_r^{\text{dis}}$$

where the symbol $\circ$ runs over $\{\text{ene}, \text{sto}, \text{dis}\}$. We assume no marginal costs for the dispatch.

The demand balancing Eq. (5) is modified to:

$$\sum_a d_{a,t} - \sum_s g_{s,t} - \sum_r g_{r,t}^{\text{dis}} + \sum_r g_{r,t}^{\text{sto}} = 0 \quad \perp \quad \lambda_t \quad \forall t \tag{B.9}$$

The standard capacity constraints apply:

$$-g_{r,t}^\circ \leq 0 \quad \perp \quad \underline{\mu}_{r,t}^\circ \quad \forall r,t \tag{B.10}$$

$$g_{r,t}^\circ - G_r^\circ \leq 0 \quad \perp \quad \overline{\mu}_{r,t}^\circ \quad \forall r,t \tag{B.11}$$

In addition we have the constraint for the consistency of the state of charge between hours according to how much was dispatched or stored:

$$g_{r,t}^{\text{ene}} - \eta_r^{\text{ene}} g_{r,t-1}^{\text{ene}} - \eta_r^{\text{sto}} g_{r,t}^{\text{sto}} + \left(\eta_r^{\text{dis}}\right)^{-1} g_{r,t}^{\text{dis}} = 0 \quad \perp \quad \lambda_{r,t}^{\text{ene}} \quad \forall r,t \tag{B.12}$$

We assume that the state of charge is cyclic $g_{r,-1}^{\text{ene}} = g_{r,T-1}^{\text{ene}}$.

From KKT stationarity we get:

$$\frac{\partial \mathscr{L}}{\partial G_r^\circ} = 0 \Rightarrow -c_r^\circ + \sum_t \overline{\mu}_{r,t}^\circ = 0 \tag{B.13}$$

$$\frac{\partial \mathscr{L}}{\partial g_{r,t}^{\text{dis}}} = 0 \Rightarrow \lambda_t + \underline{\mu}_{r,t}^{\text{dis}} - \overline{\mu}_{r,t}^{\text{dis}} - \left(\eta_r^{\text{dis}}\right)^{-1} \lambda_{r,t}^{\text{ene}} = 0 \tag{B.14}$$

$$\frac{\partial \mathscr{L}}{\partial g_{r,t}^{\text{sto}}} = 0 \Rightarrow -\lambda_t + \underline{\mu}_{r,t}^{\text{sto}} - \overline{\mu}_{r,t}^{\text{sto}} + \eta_r^{\text{sto}} \lambda_{r,t}^{\text{ene}} = 0 \tag{B.15}$$

$$\frac{\partial \mathscr{L}}{\partial g_{r,t}^{\text{ene}}} = 0 \Rightarrow \underline{\mu}_{r,t}^{\text{ene}} - \overline{\mu}_{r,t}^{\text{ene}} - \lambda_{r,t}^{\text{ene}} + \eta_r^{\text{ene}} \lambda_{r,t+1}^{\text{ene}} = 0 \tag{B.16}$$

The zero-profit rule for storage proceeds the usual way:

$$\begin{aligned}
& \sum_\circ c_r^\circ G_r^\circ = \sum_{\circ,t} G_r^\circ \overline{\mu}_{r,t}^\circ = \sum_{\circ,t} g_{r,t}^\circ \overline{\mu}_{r,t}^\circ \\
&= \sum_t \Big[\lambda_t g_{r,t}^{\text{dis}} - \left(\eta_r^{\text{dis}}\right)^{-1} \lambda_{r,t}^{\text{ene}} g_{r,t}^{\text{dis}} - \lambda_t g_{r,t}^{\text{sto}} + \eta_r^{\text{sto}} \lambda_{r,t}^{\text{ene}} g_{r,t}^{\text{sto}} \\
&\qquad - \lambda_{r,t}^{\text{ene}} g_{r,t}^{\text{ene}} + \eta_r^{\text{ene}} \lambda_{r,t+1}^{\text{ene}} g_{r,t}^{\text{ene}} \Big] \\
&\qquad = \sum_t \lambda_t \left[g_{r,t}^{\text{dis}} - g_{r,t}^{\text{sto}} \right] \\
&+ \sum_t \lambda_{r,t}^{\text{ene}} \left[-\left(\eta_r^{\text{dis}}\right)^{-1} g_{r,t}^{\text{dis}} + \eta_r^{\text{sto}} g_{r,t}^{\text{sto}} - g_{r,t}^{\text{ene}} + \eta_r^{\text{ene}} g_{r,t-1}^{\text{ene}} \right] \\
&\qquad = \sum_t \lambda_t \left[g_{r,t}^{\text{dis}} - g_{r,t}^{\text{sto}} \right]
\end{aligned} \tag{B.17}$$

The first equality is stationarity for G_r°; the second is complimentary for constraint (B.11); the third is stationarity for $g_{r,t}^\circ$ and complimentary for constraint (B.10); the fouth rearranges terms and shifts the cyclic sum over $g_{r,t}^{\text{ene}}$; the final equality uses the state of charge constraint (B.12).

The final results shows that the storage recovers its capital costs by arbitrage, charging while prices λ_t are low, and discharging while prices are high.

The relation between market value and LCOE of generators in the system is not affected by the introduction of storage (although the optimal capacities may change).

B.4. Multi-node long-term equilibrium with network

For multiple nodes the demand and generator variables gain an extra index for the node n to which they are attached, and a term is added to the objective function for the costs c_ℓ of each line capacity F_ℓ connecting the nodes:

$$-\sum_\ell c_\ell F_\ell \tag{B.18}$$

The flow can move electricity from one node to the other in each hour $f_{\ell,t}$, so that the nodal balance equation is modified

$$\sum_a d_{n,a,t} - \sum_s g_{n,s,t} = \sum_\ell K_{n\ell} f_{\ell,t} \quad \perp \quad \lambda_{n,t} \quad \forall n,t \tag{B.19}$$

where $K_{n\ell}$ is the incidence matrix for the network. This is Kirchhoff's Current Law (KCL).

There are additional constraints on the flows related to the line capacity

$$f_{\ell,t} - F_\ell \leq 0 \quad \perp \quad \bar{\mu}_{\ell,t} \quad \forall \ell,t \tag{B.20}$$

$$-f_{\ell,t} - F_\ell \leq 0 \quad \perp \quad \underline{\mu}_{\ell,t} \quad \forall \ell,t \tag{B.21}$$

and to Kirchhoff's Voltage Law (KVL):

$$\sum_\ell C_{\ell,c} x_\ell f_{\ell,t} = 0 \quad \perp \quad \lambda_{c,t} \quad \forall c,t \tag{B.22}$$

where c label an independent basis of closed cycles in the network defined by the cycle matrix $C_{\ell,c}$, and x_ℓ is the series reactance of the line.

From KKT stationarity we get in addition:

$$\begin{aligned}\frac{\partial \mathcal{L}}{\partial f_{\ell,t}} &= 0 \Rightarrow \sum_n \lambda_{n,t} K_{n,\ell} + \underline{\mu}_{\ell,t} - \bar{\mu}_{\ell,t} - \sum_c \lambda_{c,t} C_{\ell,c} x_\ell = 0 \\ \frac{\partial \mathcal{L}}{\partial F_\ell} &= 0 \Rightarrow c_\ell - \sum_t \bar{\mu}_{\ell,t} - \sum_t \underline{\mu}_{\ell,t} = 0\end{aligned} \tag{B.23}$$

and for complementary slackness:

$$\bar{\mu}_{\ell,t}\left(f_{\ell,t} - F_\ell\right) = 0 \tag{B.24}$$

$$\underline{\mu}_{\ell,t}\left(f_{\ell,t} + F_\ell\right) = 0 \tag{B.25}$$

The no-profit rule becomes:

$$c_\ell F_\ell = \sum_t \left(\bar{\mu}_{\ell,t} + \underline{\mu}_{\ell,t}\right) F_\ell \tag{B.26}$$

$$= \sum_t \left(\bar{\mu}_{\ell,t} - \underline{\mu}_{\ell,t}\right) f_{\ell,t} \tag{B.27}$$

$$= \sum_{t,n} \lambda_{n,t} K_{n,\ell} f_{\ell,t} - \sum_{t,c} \lambda_{c,t} C_{\ell,c} x_\ell f_{\ell,t} \tag{B.28}$$

The first term is the sum over flows $f_{\ell,t}$ multiplied by the price difference between the connect nodes $\sum_{t,n} \lambda_{n,t} K_{n,\ell}$, i.e. the congestion revenue. The second term is a distortion that disappears if KVL is not enforced (i.e. in a transport model with only KCL, it would not appear).

Without KVL total costs still equal total revenue, analogous to (13):

$$\sum_{n,s} c_{n,s} G_{n,s} + \sum_{n,s,t} o_{n,s} g_{n,s,t} + \sum_\ell c_\ell F_\ell \tag{B.29}$$

$$= \sum_{n,s,t} \lambda_{n,t} g_{n,s,t} + \sum_{n,\ell,t} \lambda_{n,t} K_{n,\ell} f_{\ell,t} \tag{B.30}$$

$$= \sum_{n,a,t} \lambda_{n,t} d_{n,a,t} \tag{B.31}$$

where we have used (B.19).

B.5. Non-linear generator cost functions

Suppose we have non-linear, convex functions for the cost of new capacity $C_s(G_s)$ and operation $O_s(g_{s,t})$:

$$\max_{d_{a,t}, g_{s,t}, G_s} \left[\sum_{a,t} U_{a,t}(d_{a,t}) - \sum_s C_s(G_s) - \sum_{s,t} O_s(g_{s,t}) \right] \tag{B.32}$$

subject to

$$\sum_a d_{a,t} - \sum_s g_{s,t} = 0 \quad \perp \quad \lambda_t \quad \forall t \tag{B.33}$$

$$-g_{s,t} \leq 0 \quad \perp \quad \underline{\mu}_{s,t} \quad \forall s, t \tag{B.34}$$

$$g_{s,t} - \overline{g}_{s,t} G_s \leq 0 \quad \perp \quad \overline{\mu}_{s,t} \quad \forall s, t \tag{B.35}$$

Now the relationship between costs and revenue becomes

$$G_s C_s'(G_s) + \sum_t g_{s,t} O_s'(g_{s,t}) = \sum_t \lambda_t g_{s,t} \tag{B.36}$$

This becomes a statement about *marginal profit*, i.e. small additions of capacity or generation will not generate any profit or loss.

Generators with convex cost functions with positive derivatives will make a profit since revenue will be higher than costs. For example, if $C_s(G_s) = c_s G_s^n$ for $n > 1$ and there are no operating costs, the revenue will be $nc_s G_s^n$, n times higher than the cost. These generators may however be undercut by other generators in the market with different cost functions.

The effects of support and CO_2 policies on market value are unchanged.

B.6. Equivalent problems without constraints

If we have a generic optimisation problem with variables x_l, y_m of the form

$$\max_{x_l, y_m} \left[f(x_l) - \sum_m o_m y_m \right] \tag{B.37}$$

subject to equality and inequality constraints:

$$g_i(x_l, y_m) = 0 \quad \perp \quad \lambda_i \tag{B.38}$$

$$h_j(x_l, y_m) \leq 0 \quad \perp \quad \mu_j \tag{B.39}$$

$$\sum_m c_m y_m \leq K \quad \perp \quad \mu \tag{B.40}$$

then we can prove that at the optimal point the solutions for the KKT variables λ_l, μ_j are identical to the following problem without the final constraint (B.40), where we have fixed μ from the above problem as a constant and lifted the constraint into the objective function:

$$\max_{x_l, y_m} \left[f(x_l) - \sum_m (o_m + c_m \mu) y_m \right] \tag{B.41}$$

subject to equality (i) and inequality (j) constraints:

$$g_i(x_l, y_m) = 0 \quad \perp \quad \lambda_i \tag{B.42}$$

$$h_j(x_l, y_m) \leq 0 \quad \perp \quad \mu_j \tag{B.43}$$

This holds as long as the maximisation problem is a concave function, the inequality constraints are continuously differentiable convex functions and the equality constraints are affine functions (i.e. as long as the KKT conditions are sufficient for optimality).

The lifting of the constraint into the objective function is a standard Lagrangian relaxation. The proof of equivalence of the KKT variables follows by showing that the KKT conditions are identical. From the first problem the only conditions where the extra constraint is relevant is the stationarity for y_m

$$0 = \frac{\partial \mathscr{L}}{\partial y_m} = -o_m - \sum_i \lambda_i \frac{\partial g_i}{\partial y_m} - \sum_j \mu_j \frac{\partial h_j}{\partial y_m} - c_m \mu \tag{B.44}$$

This is the same as the stationarity for the second problem, where in the second problem the term $c_m \mu$ comes from the objective function rather than the constraint. If the final constraint (B.40) is not binding, then $\mu = 0$ by complimentarity and the problems are also identical. QED.

The values of x_l, y_m are not necessarily identical, but in the case of power system problems, they often are. Since the KKT multipliers for generator constraints $\underline{\mu}_{s,t}, \overline{\mu}_{s,t}$ are identical in both problems, then generators at their upper or lower limits in the first problem are also at their limits in the second problem. The only ambiguities occur for the dispatch of generators that are neither at their lower nor at their upper limits. Where there are multiple generators setting the price with the same linear marginal cost functions, there can be multiple solutions for the same set of KKT multipliers. This is related to the fact that the constant K has disappeared from the second problem. For example, if K is a carbon dioxide budget, then the corresponding carbon tax μ might not result in a unique generator dispatch if there are many generators with the same marginal costs once the tax is included.

B.7. Supporting one group of technologies is equivalent to taxing the others

In this section it is shown that a support policy for technologies $s \in S$ with FiP μ_Γ is exactly equivalent to a tax of μ_Γ on technologies outside this group $s \notin S$ when demand is perfectly price-inelastic. Switching from forcing in technologies $s \in S$ to forcing out technologies $s \notin S$ results in the prices at each time being lifted by the same constant μ_Γ. As a result, each market value is also lifted by μ_Γ.

If S represents VRE technologies, then subsidising VRE is equivalent to taxing non-VRE. For the case that all non-VRE technologies have the same emissions factor, taxing non-VRE is equivalent to a CO_2 tax. This latter situation would be relevant for a market with VRE and a single type of gas generator.

For the proof we follow the description of the support policy in Section 3.3, with the difference that we now assume that the demand is perfectly price-inelastic in the model, i.e. that the variables $d_{a,t}$ are constants.

If a subset of generators S is singled out and forced to meet at least a fraction $\gamma \in [0,1]$ of the total demand $\sum_{a,t} d_{a,t}$, this is represented with the constraint from Eq. (19)

$$\sum_{s \in S,t} g_{s,t} \geq \Gamma = \gamma \sum_{a,t} d_{a,t} \quad \perp \quad \mu_\Gamma \tag{B.45}$$

For generators included in the constraint, $s \in S$, stationarity is

$$\frac{\partial \mathscr{L}}{\partial g_{s,t}} = 0 \Rightarrow \lambda_t = o_s - \underline{\mu}_{s,t} + \overline{\mu}_{s,t} - \mu_\Gamma \tag{B.46}$$

and for other generators $s \notin S$ we have as in Eq. (8)

$$\frac{\partial \mathscr{L}}{\partial g_{s,t}} = 0 \Rightarrow \lambda_t = o_s - \underline{\mu}_{s,t} + \overline{\mu}_{s,t} \tag{B.47}$$

Now suppose we manipulate the constraint (B.45) by subtracting both sides from the total generation:

$$\sum_{s,t} g_{s,t} - \sum_{s \in S,t} g_{s,t} \leq \sum_{s,t} g_{s,t} - \gamma \sum_{a,t} d_{a,t} \quad \perp \quad \mu_\Gamma \tag{B.48}$$

Since we subtracted (B.45), the direction of the inequality reverses. Now rearrange, remembering that we are in a lossless system with balanced demand $\sum_{s,t} g_{s,t} = \sum_{a,t} d_{a,t}$ from (5):

$$\sum_{s \notin S,t} g_{s,t} \leq (1-\gamma) \sum_{a,t} d_{a,t} \quad \perp \quad \mu_\Gamma \tag{B.49}$$

This will give exactly the same results as the previous problem, since the constraint is identical up to a sign and a constant factor added to both sides, except now we are restricting technologies not in S to be no more than a fraction $(1-\gamma)$ of the demand, and the prices λ_t are lifted by μ_Γ.

To show the effect on prices, consider stationarity for $s \in S$:

$$\frac{\partial \mathscr{L}}{\partial g_{s,t}} = 0 \Rightarrow \lambda_t = o_s - \underline{\mu}_{s,t} + \overline{\mu}_{s,t} \tag{B.50}$$

and for $s \notin S$:

$$\frac{\partial \mathscr{L}}{\partial g_{s,t}} = 0 \Rightarrow \lambda_t = o_s - \underline{\mu}_{s,t} + \overline{\mu}_{s,t} + \mu_\Gamma \tag{B.51}$$

By comparing Eqs. (B.46) and (B.47) for the support policy for S to the equivalent Eqs. (B.50) and (B.51), you can see that a subsidy for S with FiP μ_Γ is equivalent to a tax on non-S of μ_Γ. Switching from the subsidy to the tax results in the lift of all prices by a constant factor $\lambda_t \mapsto \lambda_t + \mu_\Gamma$.

From an 'effective bid' perspective, forcing in the share of S subtracts μ_Γ from S marginal cost bids, while forcing out the non-S share adds μ_Γ to the non-S bids, simply lifting all bids on the merit-order curve by μ_Γ.

Market value is also just lifted by μ_Γ for all technologies s

$$MV_s \equiv \frac{\sum_t g_{s,t} \lambda_t}{\sum_t g_{s,t}} \mapsto \frac{\sum_t g_{s,t} (\lambda_t + \mu_\Gamma)}{\sum_t g_{s,t}} = MV_s + \mu_\Gamma \tag{B.52}$$

Appendix C. Technology assumptions

The technology assumptions from the original model EMMA (Hirth, 2013) and our model PyPSA are compared in Table C.1. While nuclear and lignite with CCS are disabled in the main calculations, for the calculations in the Appendix with nuclear the costs from (Schröder et al., 2013) are applied, to reflect experience in recent projects.

Power plant lifetimes are taken from (Hirth, 2013) (nuclear has a lifetime of 50 years, while other plants have 25 years).

Battery assumptions are drawn from (Budischak et al., 2013), hydrogen (H_2) electrolysis from (Schmidt et al., 2017) and underground H2 storage from (Steward et al., 2009).

The costs of transmission expansion between the countries are derived following (Schlachtberger et al., 2017), assuming high voltage alternating current connections, that transmission covers the distance between the geographical mid-points of the countries with 25% extra length to account for non-direct routes, a 33% capacity buffer for $N-1$ failures and reactive power flows, and a 40 year lifetime for the new transmission assets.

Table C.1
Comparison of technology assumptions in the different models.

Quantity	Unit	EMMA	PyPSA
wind cost	€/kW	1300	1040
solar cost	€/kW	2000	510
nuclear cost	€/kW	4000	6000
nuclear fuel cost	€/MWh_{th}	3	3
lignite cost	€/kW	2200	2200
lignite fuel cost	€/MWh_{th}	3	3
lignite+CCS cost	€/kW	3500	n/a
lignite+CCS fuel cost	€/MWh_{th}	3	n/a
coal cost	€/kW	1500	1500
coal fuel cost	€/MWh_{th}	11.5	11.5
CCGT cost	€/kW	1000	1000
CCGT fuel cost	€/MWh_{th}	25	25
OCGT cost	€/kW	600	600
OCGT fuel cost	€/MWh_{th}	50	50
load shedding cost	€/MWh_{el}	1000	1000
battery inverter	€/kW	n/a	333
battery storage	€/kWh	n/a	167
H_2 electrolysis	€/kW_{el}	n/a	750
H_2 electrolysis efficiency	%	n/a	80
H_2 turbine	€/kW_{el}	n/a	800
H_2 storage	€/kWh	n/a	0.5
transmission expansion	€/(MWkm)	n/a	400

Appendix D. Comparison of PyPSA to EMMA results for RMV

In this section the results from (Hirth, 2013) for the long-term relative market values of solar and wind are compared to the results from the reimplementation in PyPSA. Fig. D.10 shows the relative market values in the PyPSA model with the same technology assumptions as (Hirth, 2013) and with a constraint on available renewable energy following (Hirth, 2013) (see Appendix B.1). Fig. D.11 shows the results with the wind and solar costs updated, the CO_2 price set to zero, the removal of nuclear and CCS as options, and a constraint on dispatched renewable energy following Section 3.3. Table D.2 compares the relative market values for different sampling points.

First we compare the results from EMMA (column 1 in Table D.2 and Figs. 18 and 27 in (Hirth, 2013)) and the reimplementation in PyPSA (column 2 in Table D.2 and Fig. D.10). While there is clear agreement in the overall shape and trajectory of the curves, in three of the four cases PyPSA underestimates the relative market values compared to EMMA, particularly for the case of solar at 15% penetration. There are several factors causing the disagreement between EMMA and PyPSA: EMMA has baseload incentives which alter prices; EMMA has incentives for flexible generators like OCGT that reduce their capital costs, encouraging higher marginal cost generators into the market and pushing up prices; for the denominator of the RMV, EMMA takes a simple price average over time, while PyPSA load-weights average prices over time (emphasising times of high load when prices are either higher (evening) or lower (midday solar peak)); and finally it appears the EMMA code uses a lifetime of 25 years for nuclear rather than the 50 years applied here. The solar disagreement is also large because the slope of the curve here is steep, so any deviation is magnified.

Next we compare the results from the reimplementation in PyPSA (column 2 in Table D.2 and Fig. D.10) and the version of PyPSA with updated assumptions (column 3 in Table D.2 and Fig. D.11). One of the main change in costs was a reduction in solar costs, and this is reflected in Figs. D.10 and D.11 by the fact that the case with both wind and solar now differs from the pure wind case, since solar is competitive. The reduction of the CO_2 price from 20 €/tCO_2 to zero helps to suppress prices. And finally the constraint on dispatched energy rather than available energy means that costs decrease faster and go to zero, since VRE subsidy can cause hours of negative prices. When we constrain available energy, VRE is curtailed at zero price, meaning that RMV flatlines at high penetrations as in Fig. D.10 (note that at high penetrations, a lot of the energy is curtailed).

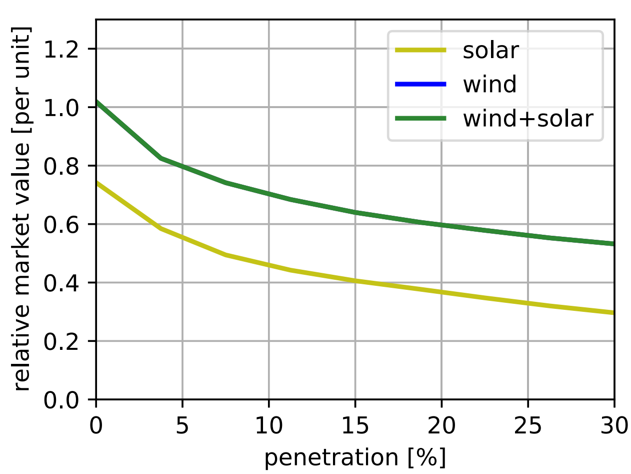

Fig. D.10. The relative market value of wind and solar as the share of their available energy is changed in the model for the case without storage or transmission reinforcement using all costs from (Hirth, 2013).

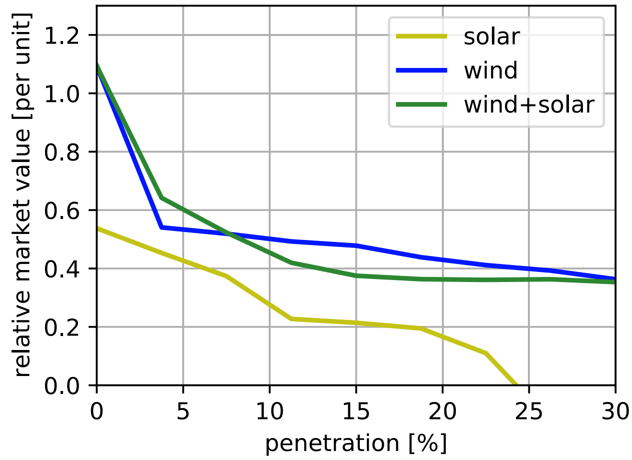

Fig. D.11. The relative market value of wind and solar as the share of their dispatched energy is changed in the model for the case without storage or transmission reinforcement using our updated costs.

Table D.2
Comparison of relative market values in the different models.

Model costs	EMMA (Hirth, 2013)	PyPSA (Hirth, 2013)	PyPSA adjusted
solar at 0%	0.9	0.74	0.54
solar at 15%	0.58	0.41	0.21
wind at 0%	1.1	1.02	1.1
wind at 30%	0.64	0.53	0.36

Appendix E. Additional results

E.1. *Support policies for wind, solar and nuclear separately*

Results for support policies applied separately to wind are shown in Fig. E.12, solar in Fig. E.13 and nuclear in Fig. E.14.

The solar market value declines much faster than for wind, as has been seen in previous results in this paper and elsewhere in the literature.

The effect of forced penetration on nuclear is similar. The equilibrium solution without the constraint does not contain nuclear, because the cost is too high; a non-zero subsidy is required to cover the difference between its average market value and the LCOE. Because it is available at all times, it achieves penetration of up to 75% before the market value declines, which corresponds to the minimum value of the load. Above this point, it reaches lower capacity factors, forcing the LCOE up and the market value down.

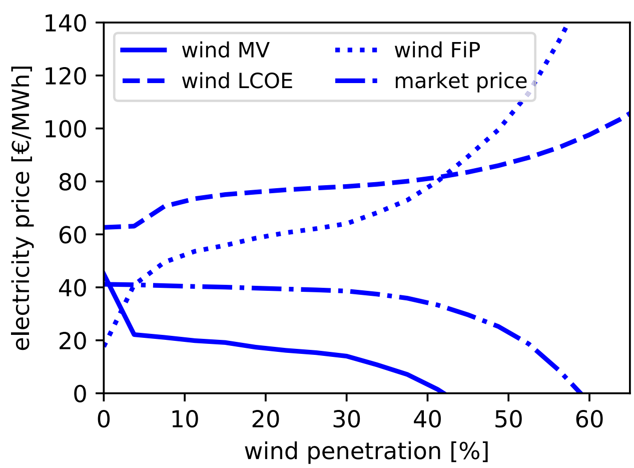

Fig. E.12. Market quantities as the penetration of wind energy covering electricity demand is increased. In this case there is no additional flexibility from storage or transmission reinforcement.

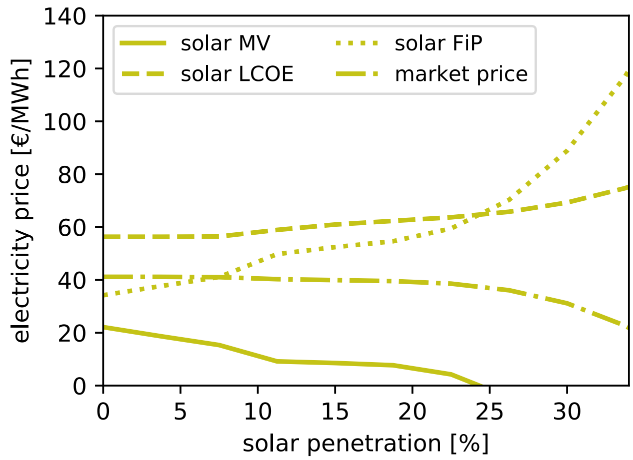

Fig. E.13. Market quantities as the penetration of solar energy covering electricity demand is increased. In this case there is no additional flexibility from storage or transmission reinforcement.

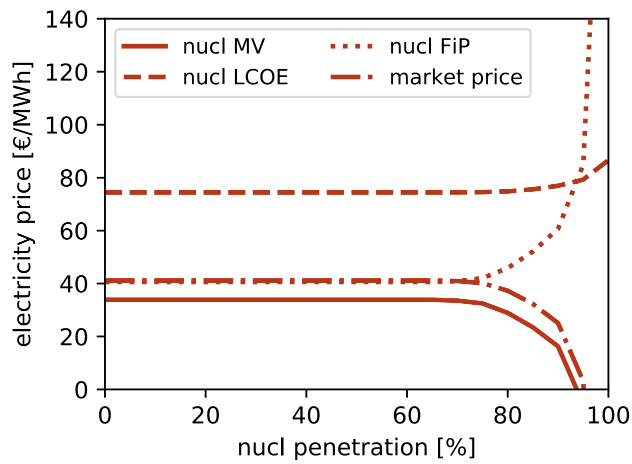

Fig. E.14. Market quantities as the penetration of nuclear energy covering electricity demand is increased. In this case there is no additional flexibility from storage or transmission reinforcement.

E.2. Support policies with no negative prices

In this section we take the results from the support policy and forbid negative prices, by setting the price to zero whenever it goes below zero. The results for systems without additional flexibility are shown for wind and solar in Fig. E.15, for wind in Fig. E.16, for solar in Fig. E.17 and for nuclear in Fig. E.18. In all cases the average market price falls only gradually. The market values still decline well below the point of cost recovery, but the decline is gentler than when negative prices are allowed, and the market values never turn negative.

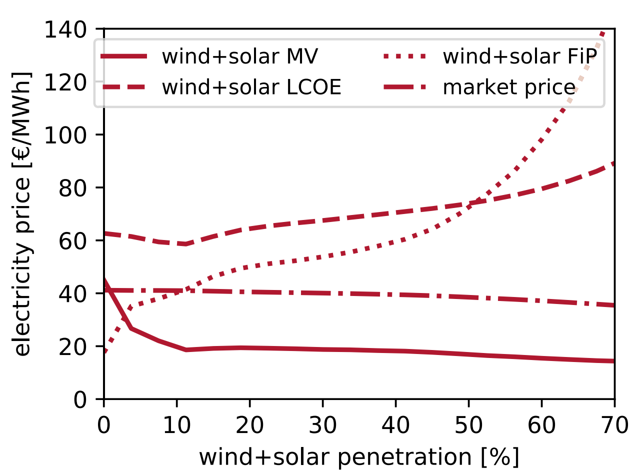

Fig. E.15. Market quantities for a VRE support policy for wind and solar with no negative prices and without additional flexibility.

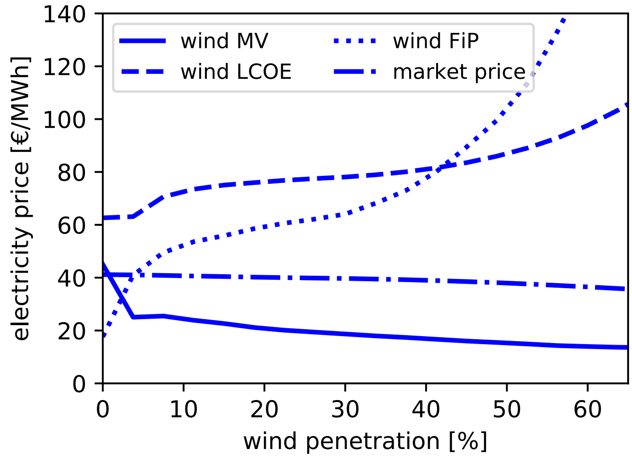

Fig. E.16. Market quantities for a VRE support policy for wind with no negative prices and without additional flexibility.

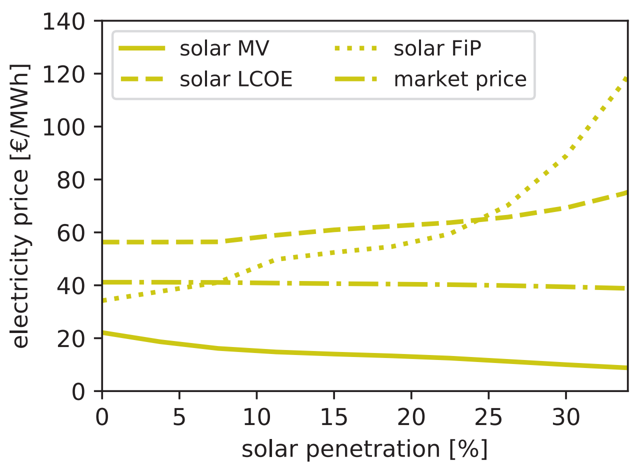

Fig. E.17. Market quantities for a VRE support policy for solar with no negative prices and without additional flexibility.

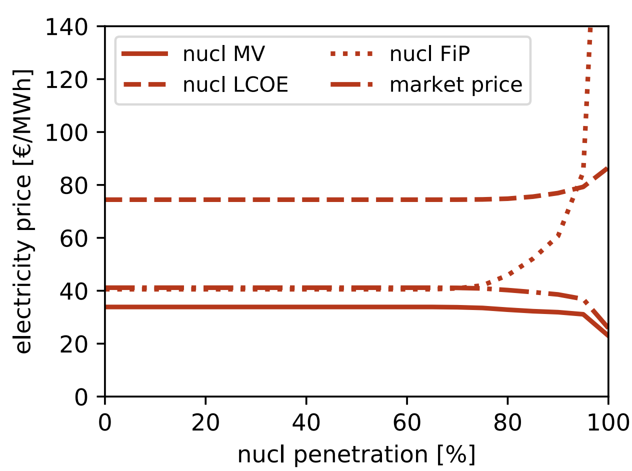

Fig. E.18. Market quantities for a VRE support policy for nuclear with no negative prices and without additional flexibility.

E.3. CO_2 policy details

In Fig. E.19 the effect of a CO_2 constraint on average market prices, wind and solar MV (equal to LCOE), the CO_2 dual price and the wind and solar penetrations are plotted. From the unconstrained equilibrium with emissions of around 1.2 tCO_2/MWh_{el} down to about 0.7 tCO_2/MWh_{el}, emissions are reduced by substituting coal for lignite, and gas for goal. Below 0.7 tCO_2/MWh_{el}, wind and solar penetrations rise steadily to replace natural gas. The CO_2 price required to reach each target rises in steps as particular fuels are substituted, before rising very steeply below 0.3 tCO_2/MWh_{el}, where it gets harder to match the variable profiles of wind and solar with the load.

The market price increases with a stricter CO_2 constraint, since the rising CO_2 price increases all effective marginal costs $o_s \rightarrow o_s + e_s\mu_K$. The market values of wind and solar initially remain steady, since they are equal to the LCOE, which is stable. However, as penetration rises, curtailment increases and the LCOE drops.

Fig. E.20 shows the corresponding figure as a function of the combined wind and solar penetration.

The analysis was repeated with the addition of transmission expansion and storage investment possibilities for battery and hydrogen storage; the corresponding results are plotted in Fig. E.21 as a function of the CO_2 limit and in Fig. E.22 as a function of penetration. With the additional flexibility, curtailment is limited and a VRE penetration of 100% without either the average market price (which reflects total system cost) or the market values rising drastically.

In Figs. E.23 and E.24 the analysis is reproduced for a scenario where the CO_2 limit is brought down with only nuclear as a low CO_2 technology. Once the CO_2 price reaches 34 €/tCO_2, nuclear is competitive with lignite and rises to a share of 68% of electricity generation. To reach 90% penetration, the CO_2 price must rise to 69 €/tCO_2.

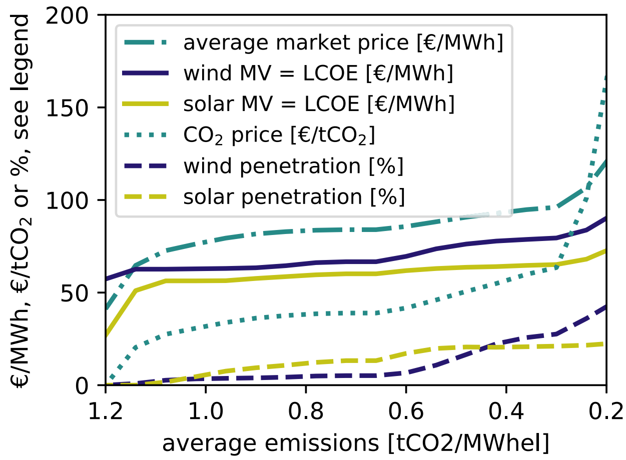

Fig. E.19. Market quantities as the average CO_2 emission factor is reduced to zero for a scenario without additional flexibility.

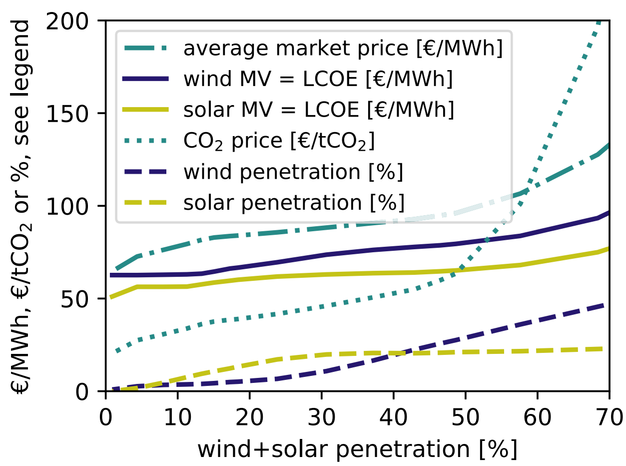

Fig. E.20. Market quantities as the average CO_2 emission factor is reduced to zero for a scenario without additional flexibility.

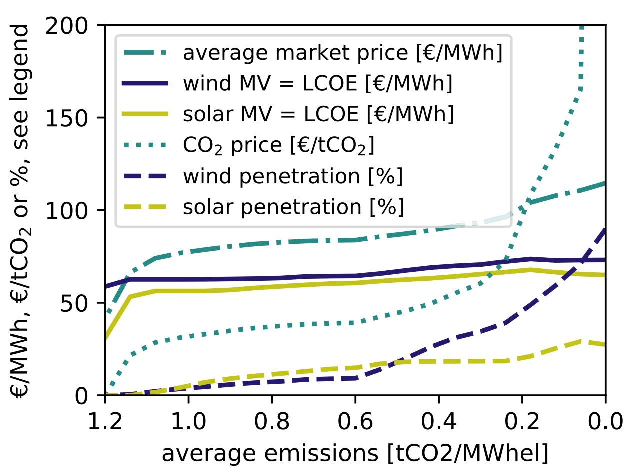

Fig. E.21. Market quantities as the average CO_2 emission factor is reduced to zero for a scenario with transmission expansion as well as short- and long-term storage.

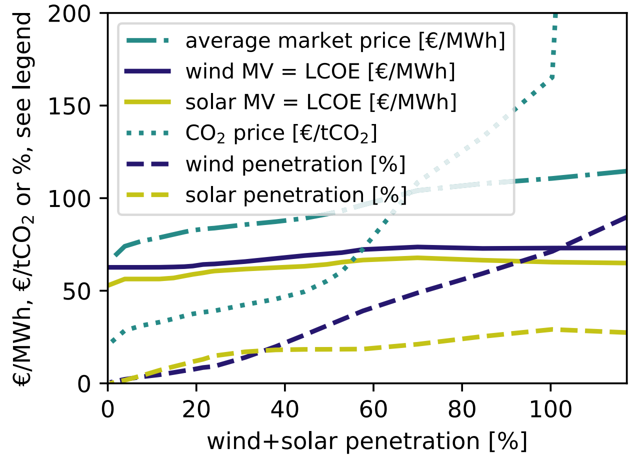

Fig. E.22. Market quantities as the average CO_2 emission factor is reduced to zero for a scenario with transmission expansion as well as short- and long-term storage.

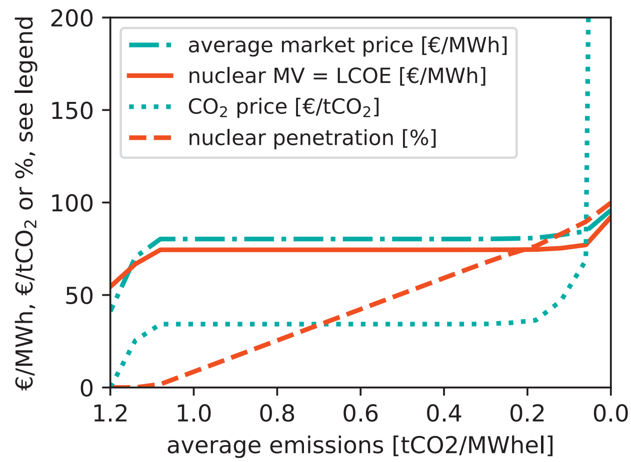

Fig. E.23. Market quantities as the average CO_2 emission factor is reduced to zero for a scenario with nuclear and no wind or solar.

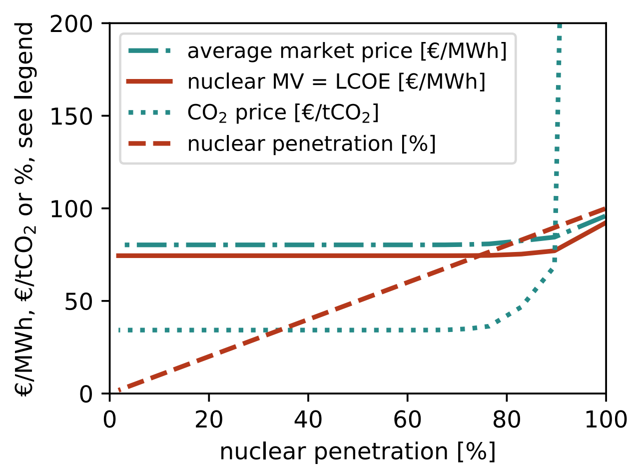

Fig. E.24. Market quantities as the average CO_2 emission factor is reduced to zero for a scenario with nuclear and no wind or solar.

E.4. Relative market value

The relative market value (RMV), also called the value factor in (Hirth, 2013), is the ratio of the market value to the load-weighted average market price, see Eqs. (17) and (18). The absolute market values from Fig. 6 are shown as relative market values in Fig. E.25. Under a VRE support policy, the RMV still goes to zero and then negative. The RMV under a CO_2 policy shows a shallow decline, which can be explained from Eq. (18). Eq. (18) shows that the RMV can also be expressed as the ratio between the technology's fraction of system costs to its share of demand. Since at full penetration VRE covers all of the demand and storage losses, the RMV simply reflects the fraction of VRE in the total system costs. The RMV ends up at 0.62, reflecting the fraction of VRE in the system costs from Fig. 7 (remaining costs coming from transmission and storage for balancing).

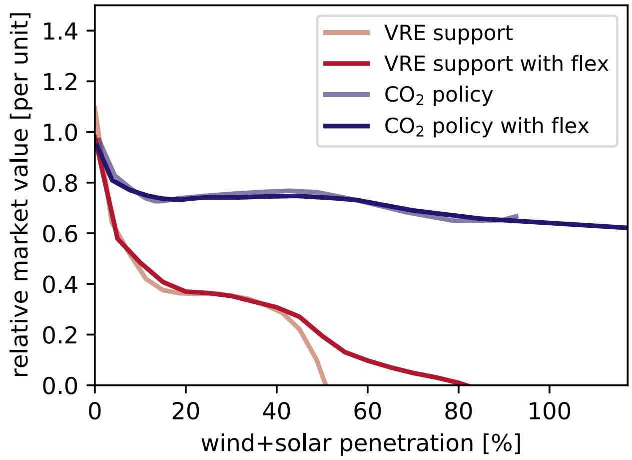

Fig. E.25. Relative market values (RMV) for VRE support versus CO_2 policies with and without flexibility.

E.5. Comparing system cost as function CO_2 emissions

In Fig. 5 we compared the system costs under the VRE and CO_2 policies as a function of the penetration of wind and solar without flexibility. In Fig. E.26 we provide the complementary figure comparing the system costs of the two policies as a function of average system CO_2 intensity. For the system setup here, the policies provide similar results until higher penetrations, at which the CO_2 policy is, unsurprisingly, more efficient at reducing CO_2 emissions.

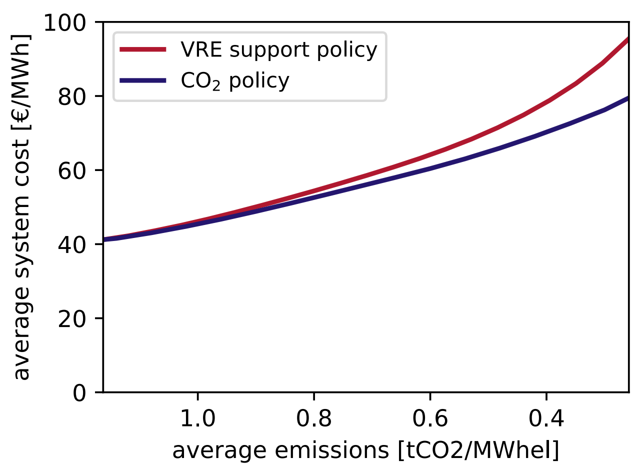

Fig. E.26. Comparison of system costs for VRE support and CO_2 policies as a function of average system CO_2 emissions, without flexibility.

E.6. Price duration curves for a CO_2 policy with flexibility

In this section we discuss the price duration curves in the model as the CO_2 budget is reduced to zero for the case of wind and solar in the presence of additional flexibility from storage and transmission reinforcement.

Fig. E.27 shows the price duration curves for different levels of average system CO_2 emissions. For higher emissions, the curve is flatter and there are no times of zero prices. As emissions reduce, there are more hours with zero prices set by wind and solar, rising to 16% of all hours, and more times with higher prices. When fossil generators are pushed out of the system, arbitrage between storage and transmission sets the non-zero prices, either by demand bids when VRE is abundant or supply bids when VRE is scarce. Note that the system does not degenerate into a singular system where prices are either zero or the value of lost load (1000 €/MWh in this case), as is sometimes assumed. Similar price duration curves were observed in a sector-coupled model in (Böttger and Härtel, 2021).

The distribution of average revenue per capacity for wind and solar over the hours is largely unchanged, see the duration curves in Figs. E.28 and E.29. The number of hours where the generators make their money shows no concentration into a few hours as emissions reduce, but is spread evenly through the year in all cases. Note that this is not the same as the market value; the area under the curve is instead equal to the annualised costs of wind and solar.

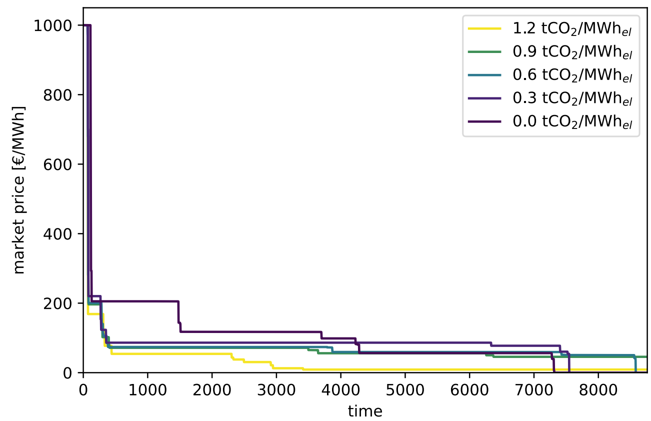

Fig. E.27. Price duration curves for CO_2 policies for different average system CO_2 emissions, with flexibility from storage and transmission reinforcement.

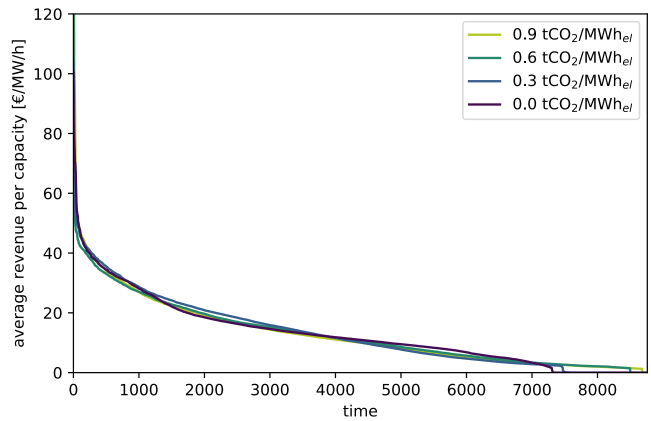

Fig. E.28. Average hourly per-capacity revenue duration curve for wind for different average system CO_2 emissions, with flexibility from storage and transmission reinforcement.

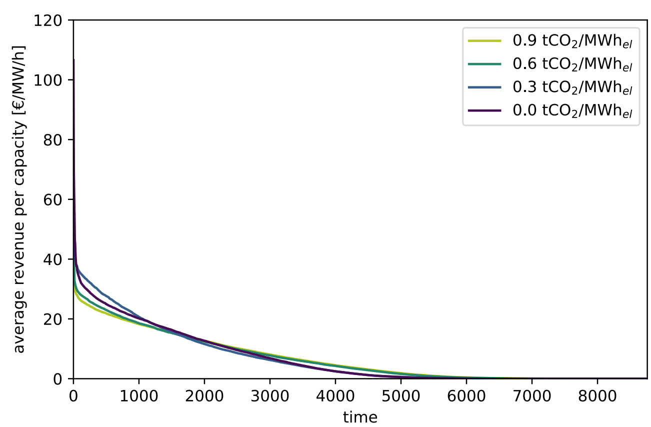

Fig. E.29. Average hourly per-capacity revenue duration curve for solar for different average system CO_2 emissions, with flexibility from storage and transmission reinforcement.

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