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The Market Value of Variable Renewables

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Summary

The income that wind and solar power receive on the market is affected by the variability of their output. At times of high availability of the primary energy source, they supply electricity at zero marginal costs, shift the supply curve (merit-order curve) to the right and thereby reduce the equilibrium price of electricity during that hour. The size of this merit-order effect depends on the amount of installed renewable capacity, the slope of the merit-order curve, and the intertemporal flexibility of the electricity system. Thus the price of wind power falls with higher penetration rates, even if the average electricity price remains constant. This work quantifies the effect of variability on the market value of renewables using a calibrated model of the European electricity market. The relative price of German wind power (value factor) is estimated to fall from 110% of the average electricity price to 50% as generation increases from zero to 30% of total consumption. For solar power, the drop is even sharper. Hence competitiveness for large-scale renewables deployment will be more difficult to accomplish than often believed.

Keywords: Wind Power, Solar Power, Electricity Market, Power Generation Economics, Renewables, Value Factor, Numerical Modelling

JEL Classification: Q42, O13, D24, D61

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The Market Value of Variable Renewables

The Effect of Solar and Wind Power Variability on their Market Income:
A model-based estimation of relative prices

Lion Hirth[1]

Abstract

The income that wind and solar power receive on the market is affected by the variability of their output. At times of high availability of the primary energy source, they supply electricity at zero marginal costs, shift the supply curve (merit-order curve) to the right and thereby reduce the equilibrium price of electricity during that hour. The size of this merit-order effect depends on the amount of installed renewable capacity, the slope of the merit-order curve, and the intertemporal flexibility of the electricity system. Thus the price of wind power falls with higher penetration rates, even if the average electricity price remains constant. This work quantifies the effect of variability on the market value of renewables using a calibrated model of the European electricity market. The relative price of German wind power (value factor) is estimated to fall from 110% of the average electricity price to 50% as generation increases from zero to 30% of total consumption. For solar power, the drop is even sharper. Hence competitiveness for large-scale renewables deployment will be more difficult to accomplish than often believed.

[1] Vattenfall Europe AG. The findings, interpretations, and conclusions expressed herein are those of the author and do not necessarily reflect the views of Vattenfall. Contact: Lion Hirth, Vattenfall Europe AG, Chausseestraße 23, 10115 Berlin, lion.hirth@vattenfall.com, +49 30 81824032. I would like to thank Falko Ueckerdt, Álvaro López-Peña Fernández, Reinhard Ellwanger, Peter Kämpfer, Wolf-Peter Schill, Christian von Hirschhausen, Mats Nilsson, Catrin Draschil, Dania Röpke, Eva Schmid, Michael Pahle, Sonja Wogrin, Albrecht Bläsi-Bentin, Simon Müller and the participants of the DSEM and YEEES seminars for valuable input and comments. The usual disclaimer applies.

1. Introduction

In many European countries electricity generation from renewable energy sources (RES) has been growing rapidly during the last years, driven by technological progress and deployment subsidies. According to official targets, the share of renewables in EU electricity consumption shall reach 35% by 2020 and 60-80% in 2050, up from 17% in 2008.[2] As the potential of hydro power is already largely exploited and biomass growth is limited by supply constraints and sustainability concerns, much of the future RES growth will need to come from wind and solar power. Solar and wind power are variable renewable energy sources (vRES)[3] in the sense that supply is determined by non-economic parameters such as climatic conditions, in contrast to "dispatchable" generators that vary output as a reaction to price changes. The market value of wind and solar power is the revenue they would earn if they sold their output on the market. It is affected by two intrinsic properties of vRES that dispatchable generators do not feature:

- The supply of vRES is *variable*. Electricity is not a homogenous good over time, because demand is variable and price-inelastic, the supply curve is upward sloping, and electricity storage is costly. Thus the value of electricity depends on the point of time it is produced.
- The output of vRES is *uncertain* until realization. The last possibility to trade on liquid markets is day-ahead, that is 12-36 hours ahead of delivery. Deviations between forecasted generation and actual production need to be compensated for by other generators or load adjustments. Coordination takes place on intraday and balancing markets. The effect of uncertainty on the market value depends on the size of the forecast errors and on these markets.

The effect of variability on revenues is sometimes called "shaping costs" or "profile costs", because it depends on the shape of the generation profile. The effect of uncertainty is called "imbalance costs". Economically, these are not costs, but reduced revenues compared to a benchmark, e.g. a dispatchable base load plant. Profile and balance costs are not market failures, but represent the intrinsic lower value of electricity during times of high supply and the economic costs of uncertainty. This paper assesses the impact of variability on the market value of vRES and provides empirical estimates of profile costs.

There are two reasons why variability affects the market value of renewables, which can be labeled correlation effect and merit-order effect. On the one hand, if the generation profile is positively correlated with demand or other exogenous parameters that increase the price, vRES receive a higher price. On the other hand, if installed vRES capacity is non-marginal, vRES supply itself influences the price: during windy and sunny hours, the additional generation shifts the merit-order curve to the right, reducing the equilibrium electricity price. The higher installed capacity is, the larger the price drop will be (Figure 1). This implies that the market value of vRES falls with higher penetration. The fundamental reason for the merit-order effect is that a) there exists a set of generation technologies that differ in their variable-to-fix costs ratio and b) electricity storage is costly. These two conditions are sufficient to make the short-term supply function upward sloping.

[2] National targets for 2020 are formulated in the National Renewable Energy Action Plans. Beurskens et al. (2011), Eurelectric (2011a), PointCarbon (2011) and ENDS (2010) provide comprehensive summaries. EU targets for 2050 have been formulated in EC (2011). Historical data are provided by Eurostat (2011).

[3] Variable renewables have been also termed intermittent, fluctuating, or non-dispatchable.

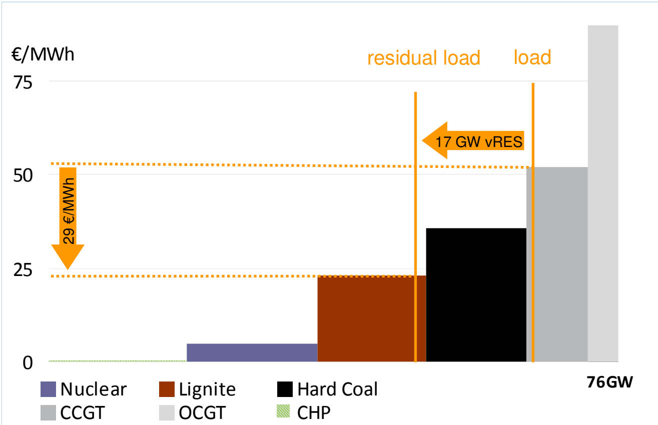

Figure 1: Merit-order effect during a specific hour. At a load of 65 GW, an additional in-feed of 17 GW of wind and solar power is estimated to reduce the equilibrium wholesale price from 53 €/MWh to 24 €/MWh.

In this paper, the market value of vRES will be measured as its relative price compared to a constant source of electricity. This relative price is called "value factor". The value factor is calculated as the ratio of the generation-weighted average electricity price and its time-weighted average (base price). It is a metric for the valence of electricity with a certain time profile relative to a flat profile [Stephenson 1973]. In other words, the wind value factor compares the value of power with varying winds with the value if winds were invariant. In economic terms, it is a relative price where the numeraire good is the base price.

Profile costs have important implications for policy makers and investors alike. Today, electricity from vRES is often subsidized and not traded at market prices. In several countries, a fixed feed-in-tariff (FiT) guarantees renewable generators a constant price, so that tax payers[4] finance intermittency costs while for investors the market value is quite irrelevant. In contrast, under green certificates obligations or premium FiTs[5], investors receive subsidies on top of market income. Under such schemes, the market value directly determines the attractiveness of vRES to investors.[6] More fundamentally, there is widespread agreement that subsidies need to be phased out in the long run. Estimating the income that vRES would earn on the market is crucial to understand if and when they become competitive.

This paper contributes to the literature in five ways. First, while the existing literature is often quite broad in scope, this works focuses on profile costs, providing a quantitative literature survey, statistical evidence, and model results. Second, relative prices (value factors) are used throughout the analysis, and the concept of value factor curves is introduced. Most of the literature reports either absolute prices, total system costs, other metrics such as \$/KW, \$/MWa, or \$/m² of area swept by wind turbines, which are difficult to compare across space, over time, and between studies. More fundamentally, relative prices have a more straightforward economic interpretation. Third, new market data are presented and analyzed econometrically, a novelty to this branch of literature. Fourth, to estimate value factors a new calibrated numerical model is developed. It models prices as well as investment endogenously, covers a large geographical area, and incorporates crucial technical con-

[4] The cost for FiT are often passed on electricity consumers. In Germany, small electricity consumers pay a specific earmarked tax on electricity that is labelled "EEG-Umlage".

[5] Countries that use a fixed FiT include Germany, Denmark, and France. Countries that use a certificate scheme or a premium FiT include Spain, UK, Sweden, Norway, and Poland. Germany recently introduced a premium FiT; see [7] on profile and imbalance costs in the context of this policy.

[6] This holds only if the certificate price is exogenous to the revenues of wind generators. If the equilibrium certificate price is determined as the gap between full costs and electricity revenues, the market value does not influence total revenues of the generator but determines the certificate price.

straints. Finally, and most importantly, this work goes beyond providing point estimates, but identifies drivers of profile costs using a comparative statics methodology and reports sensitivities. The influence of higher penetration rates of renewables is shown to be crucial. In addition, the direct and indirect effects of a number of policy, technology and price shocks on profile costs are discussed and shown to have a large impact on outcomes.

A core model result is that value factors fall quickly with higher vRES penetration. As the market share of wind power in Europe increases from zero to 30% of total electricity consumption, its value factor drops from 1.1 to 0.5. This finding holds for electricity systems with limited amounts of flexible hydro power. That means that for wind power to become competitive, cost need to fall twice as much as estimated by studies that do not take the merit-order effect into account. Despite solar power being better correlated with demand, its value factor drops even faster, because generation is concentrated in fewer hours. Model results indicate that several factors and policies have significant influence on profile costs, such as CO_2 and fuel prices, interconnector capacity, and power plant flexibility. However, the effects are sometimes quite counter-intuitive: higher gas and coal prices, for example, can *reduce* wind income by inducing investments in lignite and nuclear power.

The paper is structured as follows. Section 2 reviews the literature. Section 3 presents new market data and exposes those to regression analysis. Section 4 outlines an electricity market model that is applied in section 5 to estimate value factors of vRES and identify and quantify important drivers of those. Section 6 summarizes the results and section 7 concludes.

2. Literature review

The literature on market effects of vRES is vast. A well-known branch of this literature models estimates the effect of vRES on the average electricity price (Rathmann 2007, Sensfuß 2007, Saenz de Miera et al. 2008, Sensfuß et al. 2008, Munksgaard & Morthorst 2008, MacCormack et al. 2010, & O'Mahoney & Denny 2011, Gil et al. 2012). While some of these papers discuss the effect of vRES deployment on income of conventional generators, they do not report the effect on vRES generators' income via a change of their relative price. Others model specific consequences of vRES, such as curtailment (Denholm & Margolis 2007, Revuelta et al. 2011, Tuohy & Malley 2011), demand for back-up capacity (Weigt 2009, Mount et al. 2011) or grid stability (Eriksen et a. 2005). While these are the fundamental reasons for intermittency costs, this literature does translate technical constraints into price effects.

The literature on the market value of vRES is rather scarce. It can be divided into three branches: theoretical, empirical, and power market literature. Joskow (2011, 2012) & Borenstein (2011) discuss the theoretical differences between intermittent and dispatchable generation due to their different generation profiles. They conclude that levelized costs of electricity (LCOE), while being widely used, are an inappropriate metric to compare dispatchable and non-dispatchable technologies.[7] Bode (2006), Lamont (2008) and Twomey & Neuhoff (2010) derive analytical expressions for the market value of vRES. While Lamont uses a general functional form for the merit-order curve, Bode assumes it to be linear and Twomey & Neuhoff to be quadratic. Lamont shows that the market value of vRES can be expressed as the base price and an additive term that is a function of the covariance of vRES generation and prices. It is important to note that the covariance is not a static parameter, but a function of wind power penetration. Overall, the main contribution of the theoretical literature has been to stress the fundamental differences between dispatchable electricity sources and vRES.

[7] One might add that LCOE are also inappropriate to compare dispatchable technologies that have different variable cost and are thus dispatched differently.

The empirical literature is quite heterogeneous with respect to methodology and focus. It often has a broad scope and reports profile costs as one of many results. For this survey, value factors were calculated whenever reported data allowed doing so to facility comparison. The empirical literature can be further distinguished by the source of electricity prices. Some authors use historical market prices, as will be done in section 3. Borenstein (2008) estimates the market value of solar power in California using 2000-03 prices and a synthetic generation profile, finding value factors of 1.0 – 1.2. Sensfuß (2007) and Sensfuß & Ragwitz (2010) estimate the wind value factor in Germany to drop from 1.02 to 0.96 between 2001 and 2006, when the wind share grew from 2% to 6% and the solar value factor to fall from 1.3 to 1.1 between 2006 and 2009. Green & Vasilakos (2012) calculate wind value factors on a monthly basis (instead on a yearly one) to be 0.92 in West Denmark and 0.96 in East Denmark during the last decade. They also calculate the costs of converting Danish wind generation into a constant supply of electricity by means of imports and exports to Norway ("costs of storing") to be 3-4% of the wind value. Differences in wind profiles at different sites in the Western US are reported to lead to value factors between 0.9 and 1.05 (Fripp & Wiser 2008). Lewis (2010) takes the spatial analysis a step further by taking transmission constraints into account. Using nodal prices from Michigan he estimates the value factor to vary between 0.89 and 1.14 at different locations. Because all these studies use historical prices, they can only report value factors for historical penetration rates at historical conditions.

To relax these constraints, electricity prices need to be modeled endogenously. ISET et al. (2008) and Braun et al. (2008) use a simple three-technology model to estimate the value of solar power in Germany, but report only absolute prices. Obersteiner et al. (2009) estimate wind value factors for Austria. Assuming a polynomial merit-order curve they estimate the value factor to be 0.4 – 0.9 at 30% market share, depending on the order of the polynomial. Obersteiner & Saguan (2010) use a cost-based merit-order curve and report the wind value factor to drop from 1.02 to 0.97 as the market share in Europe grows from zero to 6%. Green & Vasilakos (2011) report a low UK wind value factors of 0.45 at 30GW installed capacity. Energy Brainpool (2011) forecast market values for hydro, onshore and offshore wind, and solar power in Germany until 2016, finding a drop of the onshore value factor to 0.84 while the offshore factor remains more stable at 0.97. While these papers capture wind fluctuations by including a large number of time steps, Valenzuela & Wang (2011) use a small number of periods in combination with stochastic modeling. Increasing the number of time steps from 16 (deterministic) to 16000 (stochastic) reduces the value factor from 1.4 to 1.1. These studies take the merit-order effect into account, but they do not account for new investments triggered by higher wind penetration.

To take into account investors' reactions on increasing vRES shares and to derive long-term equilibrium estimates of market values one needs to model investment endogenously, as will be done in section 5. Lamont (2008) uses Californian generation and load profiles, reporting the wind value factors to drop from 0.86 to 0.75 as its market share increases from zero to 16%, and solar value factors to drop from 1.2 to 0.9 as its share rises to 9%. Mills (2011) confirms these numbers and reports further value factor drops at higher market shares. Bushnell (2010) finds that wind revenues are reduced by 4-15% as the wind share increases from zero to 28% in the Western US, but doesn't provide value factors. Gowrisankaran et al. (2011) compare the revenues of solar power in Arizona to LCOE of a gas plant, which is a proxy for the long-term equilibrium base price. As the solar market share grows from 10% to 30%, the value factor drops from 0.9 to 0.7. These four models are long-term in the sense that all investment is endogenous. Nicolosi & Nabe (2011) combine endogenous investment with an existing plant stack, an approach that can be labeled "mid-term." Using a sophisticated model of the European electricity market, they estimate both the wind and the solar value factors in Germany to drop from roughly unity to 0.7 as installed capacities increase to 25% and 10% market share, respectively. All results are summarized in Table 1.

Several conclusions can be drawn from the literature. First, at low penetration rates, wind value factors are close to unity and solar value factors somewhat higher. Second, if one is interested in high penetration rates, endogenous price and investment modeling is seen as the appropriate methodology. Third, wind value factors are estimated to drop to around 0.7 at 20-40% market share. Fourth, the solar value factor is reported to drop faster than the wind factor. Fifths, some (Gowrisankaran et al. 2011, Mills 2011) also estimate balancing costs, which are reported to be 5-8% of the base price at high penetration rates. Thus profile costs seem to be higher than imbalance costs. Sixth, only one of the models features reservoir hydro power, which can be seen as a serious shortcoming of the literature. Finally, there is a strong methodological focus on numerical modelling, with no publication using other empirical methods such as regression analysis.

Table 1: Profile cost literature

Reference	**Prices**	**Technology**	**Region**	**Value Factors Estimates (at different market shares)**
Borenstein (2008)	Historical Prices	Solar	California	1.0 – 1.2 at different market design (small)
Sensfuß (2007), Sensfuß & Ragwitz (2010)	Historical Prices	Wind Solar	Germany	1.02 and 0.96 (2% and 6%) 1.33 and 1.14 (0% and 2%)
Fripp & Wiser (2008)*	Historical Prices	Wind	WECC	0.9 – 1.05 at different sites (small)
Lewis (2010)*	Historical Prices	Wind	Michigan	0.89 – 1.14 at different nodes (small)
Green & Vasilakos (2012)*	Historical Prices	Wind	Denmark	-
ISET et al. / Braun et al. (2008)	Price Model	Solar	Germany	-
Obersteiner et al. (2009)	Price Model	Wind	Austria	0.4 – 0.9 (30%)
Obersteiner & Saguan (2010)	Price Model	Wind	Europe	1.02 and 0.97 (0% and 6%)
Green & Vasilakos (2011)	Price Model	Wind	UK	0.45 (20%)
Energy Brainpool (2011)	Price Model	Onshore Offshore Hydro Solar	Germany	0.84 (12%) 0.97 (2%) 1.00 (4%) 1.05 (6%)
Valenzuela & Wang (2011)*	Price Model	Wind	PJM	-
Lamont (2008)*	Price & Investment Model	Wind Solar	California	0.86 and 0.75 (0% and 16%) 1.2 and 0.9 (0% and 9%)
Bushnell (2010)	Price & Investment Model	Wind	WECC	-
Gowrisankaran et al. (2011)	Price & Investment Model	Solar	Arizona	0.9 and 0.7 (10% and 30%)
Mills (2011)	Price & Investment Model	Wind Solar	California	1.0 and 0.7 (0% and 40%) 1.3 and 0.35 (0% and 33%)
Nicolosi & Nabe (2011)	Price & Investment Model	Wind Solar	Germany	1 and 0.7 (0% and 25%) 1 and 0.7 (0% and 10%)

None of these publications uses the term “value factor”. Output was re-calculated to derive yearly value factors.
* Published in peer-reviewed journal.

While all mentioned models assume competitive markets, Twomey & Neuhoff (2010), Green & Vasilakos (2010), and Sioshansi (2011) analyze wind market value in the context of market power of conventional generators, applying Cournot or supply function equilibrium theory. In times of little vRES supply, strategic generators can exercise market power more effectively, implying that mark-ups on competitive prices are inversely correlated with vRES in-feed. Thus market power tends to reduce the value factor of vRES. Ref. [20] reports that in a duopoly of conventional generators that engage in optimal forward contracting, the wind value factor is 0.7, as compared to 0.9 in a competitive setting.

3. Market Data

In this section, historical wind and solar value factors are calculated from vRES in-feed and ex-post market prices. In contrast to Borenstein (2008), Sensfuß (2007), and Fripp & Wiser (2008), observed in-feed data is used instead of estimated generation. These value factors are then used for regression analysis, a novelty in this branch of the literature. To start with, value factors are formally defined. The base price $\overline{p}$ is the time-weighted average wholesale day-ahead price. In matrix notation,

$$\overline{p} = \mathbf{p'i} / \mathbf{i'i} \tag{1}$$

where $\mathbf{p}$ is a vector of hourly spot prices and $\mathbf{i}$ a vector of ones**,** both with dimensionality $(1xT)$ where T is the number of hours, usually 8760 for the entire year. The average revenue of wind power $\overline{p}^w$ is the wind-weighted spot price:

$$\overline{p}^w = \mathbf{p'g/g'i} \tag{2}$$

where the generation profile $\mathbf{g}$ is a vector of hourly generation factors that sum up to the yearly full load hours (FLH) and $\mathbf{p'g}$ is the yearly revenue while $\mathbf{g'i}$ the yearly output. Generation profiles of individual generators or groups of generators can be used. In this work, generators are grouped by country. The wind value factor v^w is defined as the ratio of average wind revenues to the base price:

$$v^w = \overline{p}^w / \overline{p} \tag{3}$$

The solar value factor is defined accordingly. This definition relies on day-ahead prices only and ignores other market channels such as future and intraday markets (see Obersteiner and von Bremen 2009 for a discussion).

Day-ahead spot prices were taken from various exchanges. Generation profiles are not directly available at the country level. They were calculated as hourly in-feed over installed capacity. In-feed data come from transmission system operators (TSOs) and capacity data from TSOs and industry statistics. Installed wind capacity is usually reported on a yearly basis and was interpolated to account for changes during the year. Because solar capacity has changes rapidly and at different speeds, daily capacity data from the regulator was. German wind data from 2001-06 are not published by the TSOs and were taken from Sensfuß (2007). German solar in-feed is only published by one TSO, whose data were used as a proxy for Germany.[8]

Table 2 reports some descriptive statistics for Germany. The average value factor during the last years was 0.95 and for solar 1.18, solar being valued higher due to its stronger positive correlation with demand. At low penetration rates both value factors were above unity, which can be explained by the correlation effect. With wind power increasing its market share from 2% to 7% from 2001-11 and solar from 1% to 3% from 2006-11, the respective value factors dropped by 0.10 and 0.14, which is due to the merit-order effect. The wind value factor increased slightly during 2007-10, despite installed wind capacity continued to grow. Three potential reasons are a) a flatter merit-order curve due to a shift in the gas-to-coal-price ratio and CO_2 pricing, b) more efficient international trade due to market coupling, and c) the impact of solar power that reduces the base price more than the average revenue of wind power. To conclude, market data suggest that the merit-order effect significantly reduced the market value of vRES even at quite modest market shares in the single digit range.

[8] In-feed data come from the TSOs Statnett, Svenska Kraftnät, Energienet.dk, 50 Hertz, Amprion, TenneT, EnWG, Elia. Price data were obtained from the electricity exchanges EPEX-Spot, Nordpool, and APX. Installed capacities were taken from BMU (2011), BNetzA Stammdatenbank, World Wind Energy Association (2011), and European Wind Energy Association (2011). German solar data are taken from 50Hertz TSO. Generation in Germany correlates very well with generation in the 50Hertz area ($\rho = .93$), so the proxy seems appropriate. All data are available from the author upon request.

Table 2: Historical vRES value factors and revenues for Germany

		Wind		Solar	
	$\overline{p}$ (€/MWh)	$\overline{p}^w$ (€/MWh)	v^w (1)	$\overline{p}^w$ (€/MWh)	v^w (1)
2001	24	25*	1.02	-	-
2004	29	29*	1.00	-	-
2005	46	46*	.99	-	-
2006	51	49*	.96	68**	1.33
2007	38	33	.88	44**	1.16
2008	66	59	.90	82	1.25
2009	39	35	.91	44	1.14
2010	44	42	.95	49	1.11
2011	51	47	.92	56	1.09
Average	**43**	**41**	**.95**	**58**	**1.18**

* Estimates from Sensfuß (2007) and **from Sensfuß & Ragwitz (2010) based on modeled in-feed. For comparison: LCOE of onshore wind in Germany are around 70 €/MWh, about 30 €/MWh above revenues.

Table 3 reports wind value factors for more European countries for which data were available. They have been between 0.91 and 1.01 in all countries. One can observe that value factors are close to unity in Nordic countries. The Nordic electricity system is dominated by a large share of hydro reservoir generation. Such a "hydro system" features considerable intertemporal flexibility, leading to a quite flat price profile: Neither short-term demand fluctuations nor wind fluctuations have a significant impact on the spot price. Also, the market share of wind power is smaller in the Nordic than in Germany or Denmark. The German electricity system is a "thermal system" dominated by thermal power plants without significant flexibility to shift generation over time. Thus the price is sensitive to both demand and vRES-induced supply fluctuations. One can expect the merit-order effect to be much more pronounced in thermal systems than in hydro systems, which seems to be confirmed by market data. Western Denmark is highly interconnected to Germany while Eastern Denmark is better connected to Nordic, which helps explain their respective value factors.

Table 3: Wind value factors in different countries

	Germany	Denmark-West	Denmark-East	Sweden	Norway
2007	0.88	0.88	0.92	1.03	-
2008	0.90	0.90	0.93	0.97	-
2009	0.91	0.96	1.00	1.01	0.99
2010	0.94	0.96	0.99	1.01	1.03
2011	0.92	0.94	0.93	n/a	n/a
Average	**0.91**	**0.93**	**0.95**	**1.01**	**1.01**

To identify and quantify causal relationships beyond descriptive statistics, these data are exposed to econometric methods, a novelty in the literature. Two hypotheses are tested. First, more installed capacity reduces the value factor, and second, the drop is more pronounced in thermal systems. The regression model includes the market share of wind power, a dummy for thermal system that interacts with the share, and time dummies as control variables to capture fuel and CO_2 price shocks:

$$v_{t,c}^{w} = \beta_0 + \beta_1 \cdot share_{t,c} + \beta_2 \cdot share_{t,c} \cdot thermal_c + \beta_3 \cdot time\_dummies_t + \varepsilon_{t,c} \qquad (4)$$

where $\varepsilon \sim iid(0,\sigma^2)$ and t,c are indices for time and countries, respectively. The model is specified as a random effects model and estimated using GLS. Two versions are estimated, one based on yearly values and one on monthly values.

The results, which are summarized in table 4, are striking: increasing the market share of wind by one percentage point is estimated to reduce the value factor by 0.23 (0.19-0.26) percentage points in hydro systems (β_1) and by 0.97 (0.83-1.11) percentage points in thermal systems $(\beta_1 + \beta_2)$. The wind value factor without any installed wind capacity is estimated to be 0.97 (0.95 – 1.00)(β_0). There is one important reason that probably introduces a downward bias to the coefficients: While value factors have been dropping with higher wind penetration in Denmark and Germany, the drop is softened by international trade: During wind hours, net exports help stabilizing the price. If surrounding countries had similar wind penetration rates, given the high correlation between winds, the drop would be larger.

In both models, the respective coefficients are similar in size and highly significant at conventional levels. Thus both hypotheses cannot be rejected. However, since observed changes in penetration rates are rather small compared to long-term ambitions, one has to interpret econometric results cautiously: while we are interested in market values of renewables at 30% or 50% market share, historically it varied only by a few percentage points. Fundamental economic modeling is applied as an alternative empirical methodology in the next sections.

Table 4: Regression results

Model	(1) Time resolution: years	(2) Time resolution: month
Dependent variable	Wind value factor (%)	Wind value factor (%)
Share of wind power (% of consumption)	-0.26*** (3.7)	-0.19*** (6.4)
Share of wind power * Thermal dummy	-0.85*** (4.3)	-0.64*** (7.7)
Time Dummies	(5 variables omitted)	(78 variables omitted)
Constant	94.7*** (42.3)	99.9*** (43.0)
R^2 within/between/overall	.63 / .95 / .80	.50 / .99 / .60
Number of obs	20	257

*** significant at 1% level; absolute t-values in brackets

4. Model description

To derive value factors under different prices and policies, at high wind penetration rates, and in a medium-term model as well as the long-term economic equilibrium, a stylized numerical model of the North-Western European electricity market was developed. The model minimized total costs with respect to investment, production and trade decisions under a large set of technical constraints. Assuming perfect competition, total cost minimization is equivalent to profit-maximization of decentralized agents. The model is linear, deterministic, and solved at hourly resolution for a full year. This section discusses crucial features verbally, outlines model equations and input data, and presents back-testing results. A graphical model representation can be found in the appendix (Figure A1).

4.1 Overview

Generation is modeled as eleven discrete technologies with continuous capacity: two variable renewables with zero marginal costs, wind and solar, seven thermal technologies with economic dispatch, nuclear, lignite, hard coal, combined cycle gas turbines (CCGT), open cycle gas turbines (OCGT), and lignite carbon capture and storage (CCS), a generic "load shedding" technology, and pump hydro storage. vRES generation is given by exogenous generation profiles. Dispatchable plants produce when the price is above variable costs. Storage is optimized endogenously under turbine, pumping, and storage volume constraints. An energy-only market is modeled. Curtailment is possible at zero costs, which implies that the electricity price does not become negative. The existing power plant fleet is included as sunk investment. New investment is possible in all generation technologies as well as storage and will be done if plants earn a return on investments of 7%. Existing plants are decommissioned if they do not cover their quasi-fixed costs.

Demand is given exogenous by hour and thus assumed to be perfectly price inelastic at all but very high prices, when load is shed. While abstracting from price-elasticity is a standard assumption in dispatch models, it is somewhat problematic with respect to the investment decision, which takes place at longer time scales. However, the average electricity price does not vary dramatically between model runs. Hourly demand as well as wind and solar generation factors are derived from real data of the same year. This ensures that crucial correlations across space, over time, and between parameters are captured.

Combined heat and power (CHP) generation is modeled as a must-run load by technology. That means that a certain share of the heat-providers lignite, hard coal, CCGT and OCGT are forced to run even if prices are below their variable costs. The remaining capacity of that technology is freely available for optimization. Investment and disinvestment in CHP generation is possible, but the total amount of CHP capacity cannot be reduced.

Cross-border trade is endogenous and limited by net transfer capacities (NTCs) while within regions transmission capacity is assumed to be not binding. Endogenous investment in interconnector capacity is possible and done if capacity and generation cost reductions exceed annualized investment costs for interconnectors.

The model is linear and does not feature any explicit integer constraints such as start-up cost, minimum load or minimum downtime conditions. Thus, it is not a unit commitment model. However, start-up costs are parameterized to achieve a more realistic bidding behavior: Baseload plants bid an electricity price below their variable costs in order to avoid ramping and start-ups. Ancillary services are not explicitly modeled. However, it is attempted to proxy their effects on dispatch and investment through a must-run constraint for dispatchable generators, and a proxy for income from reserve markets.

The most obvious caveat of the model is the absence reservoir hydro power. In Nordic, France, Spain, and the Alps significant capacities of long-term reservoir hydro power are available that offer intertemporal flexibility and hence will help keeping up value factors of vRES. For that reason only thermal systems are modeled and results do not apply to hydro systems; French hydro is proxied by reducing demand during peak hours.

The model is calibrated to North-Western Europe and covers Germany, Belgium, Poland, The Netherlands, and France. Back-testing shows that crucial features of the power market can be replicated fairly well, such as price level, price spreads, interconnector flows, peak / off-peak spreads, and the capacity and generation mix.

4.2 Total System Costs

The model minimizes total system costs C with respect to a large number of decision variables and technical constraints. Total system costs are the sum of fix generation costs $C_{r,i}^{fix}$, variable generation costs $C_{t,r,i}^{\mathrm{var}}$, and investment costs into storage C_{r}^{sto} and transmission $C_{r,rr}^{trans}$ over all generation technologies i, regions r, and time steps t:

$$\begin{aligned} C &= \sum_{r,i} C_{r,i}^{fix} + \sum_{r,i,t} C_{t,r,i}^{var} + \sum_{r} C_{r}^{sto} + \sum_{r,rr} C_{r,rr}^{trans} \\ &= \sum_{r,i} \left(\hat{g}_{r,i}^{inv} \cdot \left(c_i^{inv} + c_i^{qfix} \right) + \hat{g}_{r,i}^{0} \cdot c_i^{qfix} \right) + \sum_{r,i,t} g_{t,r,i} \cdot c_i^{\mathrm{var}} + \sum_{r} \hat{s}_{r}^{io,inv} \cdot c^{sto} + \sum_{r,rr} \hat{x}_{r,rr}^{inv} \cdot \delta_{r,rr} \cdot c^{NTC} \end{aligned} \quad (5)$$

where $\hat{g}_{r,i}^{inv}$ is the investments in generation capacity and $\hat{g}_{r,i}^{0}$ are existing capacities, c_i^{inv} are annualized specific capital costs and c_i^{qfix} are yearly quasi-fixed costs such as fixed operation and maintenance (O&M) costs. Variable costs are the product of hourly generation $g_{t,r,i}$ with specific variable costs c_i^{var} that include fuel, CO_2, and variable O&M costs. Investment in pump hydro storage capacity $\hat{s}_{r}^{io,inv}$ comes at an annualized capital cost of c^{sto} but without variable costs. Transmission costs are a function of additional interconnector capacity $\hat{x}_{r,rr}^{inv}$, distance between markets $\delta_{r,rr}$, specific annualized investment costs per MW-km c^{NTC}. Investment and generation are decision variables while costs and $\hat{g}_{r,i}^{0}$ are parameters. Hats denote capacities that constrain the respective flow variables and Greek letters denote parameters. There are eleven technologies, five regions, and 8760 times steps modelled. Note that (5) does not contain a formulation for distribution grid costs, which in reality is a significant share of household electricity costs.

4.3 Supply and Demand

The energy balance (6) is the central constraint of the model. Demand $d_{t,r}$ has to be met by supply during every hour and in every region. Supply is the sum of generation $g_{t,r,i}$ minus the sum of net exports $x_{t,r,rr}$ plus storage output $s_{t,r}^{o}$ minus storage in-feed $s_{t,r}^{i}$. Storage efficiency is given by η. The electricity price $p_{t,r}$ is defined as the shadow price of demand and has the unit €/MWh (7). Note that (6) features an inequality, implying that supply can always be curtailed and that the price does not become negative. The model can be interpreted as representing an energy-only market without capacity payments, and $p_{t,r}$ can be understood as the market-clearing spot price as being implanted in many deregulated wholesale electricity markets.

$$d_{t,r} \leq \sum_{i} g_{t,r,i} - \sum_{rr} x_{t,r,rr} + \eta \cdot s_{t,r}^{o} - s_{t,r}^{i} \qquad \forall t,r \quad (6)$$

$$p_{t,r} \equiv \frac{\partial C}{\partial d_{t,r}} \qquad \forall t,r \quad (7)$$

Generation is constraint by available installed capacity. Equation (8) states the capacity constraint for the vRES technologies j, wind and solar power. Equation (9) is the constraint for dispatchable generators k, which are nuclear, lignite, hard coal, CCGT, and OCGT as well as load shedding. Note that technology aggregates are dispatched, not individual blocks or plants. Renewable generation is constraint by exogenous generation profiles $\varphi_{t,r,j}$ that captures both the availability of the underlying primary energy source as well as technical non-availability. Availability $\alpha_{t,r,k}$ is the technical availability of dispatchable technologies due to maintenance. Dispatchable capacity can be decommissioned endogenously via $c_{r,k}^{dec}$ to save on quasi-fix costs, while vRES capacity cannot. Both generation and capacities are continuous variables. The value factors $v_{r,j}$ are defined as the average revenue of wind and solar relative to the base price (10), equivalent to (3).

$$g_{t,r,j} = \hat{g}_{r,j} \cdot \varphi_{t,r,j} = \left(\hat{g}_{r,j}^{0} + \hat{g}_{r,j}^{inv}\right) \cdot \varphi_{t,r,j} \qquad \forall t,r,j \in i \tag{8}$$

$$g_{t,r,k} \le \hat{g}_{r,k} \cdot \alpha_{t,r,k} = \left(\hat{g}_{r,k}^{0} + \hat{g}_{r,k}^{inv} - \hat{g}_{r,k}^{dec}\right) \cdot \alpha_{t,r,k} \qquad \forall t,r,k \in i \tag{9}$$

$$v_{r,j} \equiv \sum_{t} g_{t,r,j} \cdot p_{t,r} \Big/ \sum_{t} p_{t,r} \qquad \forall r,j \in i \tag{10}$$

Minimizing (3) under the constraint (9) implies that technologies generate if and only if the electricity price as defined in (7) is equal or higher than variable costs. It also implies the electricity price equals variable costs of a plant if the plant is generating, but the capacity constraint is not binding. Finally, this formulation implies that if all capacities are endogenous, all technologies earn zero profits, which is the long-term economic equilibrium (for a proof see Hirth & Ueckerdt 2012).

4.4 Power System Inflexibilities

One of the main ambitions of this model is, while remaining parsimonious in notation, to include crucial constraint and inflexibilities of the power system, especially those that force generators to produce at prices below their variable costs (must-run constraints). Three types of such constraints are taken into account: CHP generation where heat demand limits flexibility, a must-run requirement for providers of ancillary services, and costs related to ramping, start-up and shut-down of plants. Both heat and ancillary services are goods that are produced jointly with electricity and that limit the flexibility of producers to react to electricity prices. These inflexibilities in conjuncture with subsidies vRES generation are the reason for electricity prices to become negative at times in practice.

One of the major inflexibilities in European power systems is combined heat and power (CHP) generation, where heat and electricity is produced in one integrated process. Most importantly, high demand for heat forces plants to stay online and generate electricity, even if the electricity price is below variable costs. The CHP must-run constraint (11) guarantees that generation of each CHP technology h, which are the five coal- or gas-fired technologies, does not drop below minimum generation $g_{t,r,h}^{min}$. Minimum generation is a function of the amount of CHP capacity of each technology $\kappa_{r,h}$ and the heat profile $\varphi_{t,r,chp}$. The profile is based on ambient temperature and captures the distribution of heat demand over time. CHP capacity of a technology has to be equal or smaller than total capacity of that technology (12). Furthermore, the current total amount of CHP capacity in each region γ_r has to remain at least constant (13). Investments in CHP capacity $\kappa_{r,h}^{inv}$ as well as decommissioning of CHP $\kappa_{r,h}^{dec}$ are possible, but only to the extent that total power plant investments and disinvestments take place (15), (16). Taken together, (12) – (16) allow fuel switch in the CHP sector, but do not allow reducing total CHP capacity. For both the generation constraint (11) and the capacity constraint (13) one can derive shadow prices $p_{t,r,h}^{CHPgene}$ (€/MWh) and $p_{r}^{CHPcapa}$ (€/KWa), which can be interpreted as the opportunity costs for heat supply.

$$g_{t,r,h} \geq g_{t,r,h}^{min} = \kappa_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} \qquad \forall t,r,h \in k \qquad (11)$$

$$\kappa_{r,h} \leq \hat{g}_{r,h} \qquad \forall r,h \qquad (12)$$

$$\sum_h \kappa_{r,h} \geq \gamma_r = \sum_h \kappa_{r,h}^0 \qquad \forall r \qquad (13)$$

$$\kappa_{r,h} = \kappa_{r,h}^0 + \kappa_{r,h}^{inv} - \kappa_{r,h}^{dec} \qquad \forall r,h \qquad (14)$$

$$\kappa_{r,h}^{inv} \leq \hat{g}_{r,h}^{inv} \qquad \forall r,h \qquad (15)$$

$$\kappa_{r,h}^{dec} \leq \hat{g}_{r,h}^{dec} \qquad \forall r,h \qquad (16)$$

$$p_{r,t}^{CHPgene} \equiv \frac{\partial C}{\partial \varphi_{r,t}^{chp}} \qquad \forall r,t \qquad (17)$$

$$p_r^{CHPcapa} \equiv \frac{\partial C}{\partial \lambda_r} \qquad \forall r \qquad (18)$$

Electricity systems require a range of measures to ensure stability across different dimension. These measures are called ancillary services. Many ancillary services can only be supplied by generators while producing electricity, such as regulating power or reactive power (voltage support). Thus, a supplier that committed to provide such services over a certain time (typically much longer than the delivery periods on the spot market) has to produce electricity even if the spot prices falls below its variable costs. In this model, ancillary service provision is implemented as a must-run constraint (19), similar to Denholm and Margolis (2007): An amount of σ_r of dispatchable capacity has to be in operation at any time. σ_r is set to 20% of the annual peak demand of that region. CHP generators cannot provide ancillary services, but pump hydro storage can provide them while pumping and generating. For a region with a peak demand of 80 GW, at any point of time 16 GW of dispatchable generators or storage have to be online. Note that with a pump capacity of 8 GW this condition could be fulfilled without delivering any electricity to consumers. The shadow price of σ_r, $p_{t,r}^{AS}$,is defined as the price of ancillary services, with the unit €/KW$_{\text{online}}$a.

$$\sum_k g_{t,r,k} - \sum_h \kappa_{r,h} \cdot \varphi_{t,r,chp} \cdot \alpha_{t,r,h} + \eta \cdot s_{t,r}^o + s_{t,r}^i \geq \sigma_r = 0.2 \cdot \max_t (d_{t,r}) \qquad \forall t,r \qquad (19)$$

$$p_r^{AS} \equiv \frac{\partial C}{\partial \sigma_r} \qquad \forall r \qquad (20)$$

Finally, thermal power plants have limits to their operational flexibility, even if they don’t produce other goods besides electricity. Physical constraints on the temperature gradients of boilers, turbines, and fuel gas treatment facilities and thermodynamic laws imply that increasing or decreasing output (ramping), running at partial load, and shutting down or starting up plants are costly. In the case of nuclear power plants, the physics of nuclear reactions related to Xenon-135 sets further limits on ramping and minimal down time of plants. These multitudes of constraints are proxied in the present framework by forcing certain generators to produce below variable costs. This is implemented as a “run-through premium” for nuclear, lignite, and hard coal plants. For example, nuclear plants’ variable cost is reduced by 10 €/MWh. In order to not decrease full costs, fix costs are increased by 87600 €/MWa in turn.

4.5 Flexibility options

The model aims not only at capturing major inflexibilities of existing power technologies, but also to model important flexibility options. Transmission expansion and electricity storage are major possibilities to make electricity systems more flexible and are discussed in the following.

Within regions, the model abstracts from grid constraints, applying a "copperplate" assumption. Between regions, transmission capacity is constrained by net transfer capacities (NTCs). Ignoring transmission losses, the net export $x_{t,r,rr}$ from r to rr equals net imports from rr to r (21). Equations (22) and (23) constraint electricity trade to the sum of existing interconnector capacity $\hat{x}^0_{r,rr}$ and new interconnector investments $\hat{x}^{inv}_{r,rr}$. Equation (25) ensures lines can be used in both directions. Recall from (5) that interconnector investments have fixed specific investment costs, which excluded economies of scale as well as non-linear transmission costs due to the nature of meshed HVAC systems. The distance between markets $\delta_{r,rr}$ is measured between the geographical centres of markets. The shadow price of the transmission constraint $p^x_{t,r}$ as defined in (25) can be interpreted as the congestion rent that the owner of the lines earnes.

$$x_{t,r,rr} = -x_{t,rr,r} \qquad \forall t,r,rr \qquad (21)$$

$$x_{t,r,rr} \le \hat{x}_{r,rr} = \hat{x}^0_{r,rr} + \hat{x}^{inv}_{r,rr} \qquad \forall t,r,rr \qquad (22)$$

$$x_{t,rr,r} \le \hat{x}_{rr,r} = \hat{x}^0_{rr,r} + \hat{x}^{inv}_{rr,r} \qquad \forall t,r,rr \qquad (23)$$

$$\hat{x}^{inv}_{rr,r} = \hat{x}^{inv}_{r,rr} \qquad \forall r,rr \qquad (24)$$

$$p^x_{t,r} \equiv \frac{\partial C}{\partial \hat{x}_{r,rr}} \qquad \forall t,r \qquad (25)$$

The only electricity storage technology applied commercially today is pump hydro storage. Thus storage is modeled after pump hydro. Other storage technologies such as compressed air have similar characteristics in terms of cycle efficiency, power-to-energy ratio, and specific costs and would have similar impact on model results. Other storage technologies such as batteries or gasification have very different characteristics and are not captured in the model. The amount of energy stored at a certain hour $s^{vol}_{t,r}$ is last hour's amount minus generation $s^o_{t,r}$ plus in-feed $s^i_{t,r}$ (26). Both pumping and generation is limited by the turbines capacity $\hat{s}_r$ (27), (28). The amount of stored energy is constrained by the volume of the reservoirs $\hat{s}^{vol}_r$, which are assumed to be designed such that they can be filled within eight hours (29). Hydrodynamic friction causes the cycle efficiency to be below unity (6). The only costs related to storage except losses are capital costs in the case of new investments $\hat{s}^{inv}_r$ (5). The water value $p^{water}_{t,r}$ is defined as the shadow price of stored energy (30).

$$s^{vol}_{t,r} = s^{vol}_{t-1,r} - s^o_{t,r} + s^i_{t,r} \qquad \forall t,r \qquad (26)$$

$$s^i_{t,r} \le \hat{s}_r = \hat{s}^0_r + \hat{s}^{inv}_r \qquad \forall t,r \qquad (27)$$

$$s^o_{t,r} \le \hat{s}_r = \hat{s}^0_r + \hat{s}^{inv}_r \qquad \forall t,r \qquad (28)$$

$$s^{vol}_{t,r} \le \hat{s}^{vol}_r = \left(\hat{s}^0_r + \hat{s}^{inv}_r\right) \cdot 8 \qquad \forall t,r \qquad (29)$$

$$p^{water}_{t,r} \equiv \frac{\partial C}{\partial s^{vol}_{t,r}} \qquad \forall t,r \qquad (30)$$

The model is written in GAMS and solved by Cplex using a primal simplex method. With five countries and 8760 times steps, the model consists of one million equations and four million non-zeros. The solving time on a personal computer is about half an hour per run with endogenous investment and a few minutes without investment.

4.6 Input Data

Two types of data are inputted to the model: time series data for every hour of the year, and scalar data. Hourly information is used for each region's demand, the heat profile, and the generation profile of wind and solar power. Real data from the same year is used in order to preserve empirical correlations across space, over time, and between variables. Sensitivity tests indicate these correlations are crucial to estimate value factors accurately. For example, the high correlation of 0.94 between German and French wind generation affects strongly the effect of transmission expansion between these countries (5.4). Load data were taken from various TSOs (see section 3). Heat profiles are based on ambient temperature. Historical wind and solar generation data are only available from a few TSOs, and these series are not representative for large-scale wind penetration if they are based on a small number of wind turbines: At higher penetration rate, a wider dispersed wind power fleet will cause the profile to be smoother. Thus vRES profiles were estimated from historical weather data using empirical estimated aggregate power curves. Wind load factors in all countries are scaled to 2000 FLH. Data from 2010 were used for this paper. Table 5 reports coefficients of correlations for a number of time series. Note that wind is quite well correlated with demand, mainly due to seasonality. Note also that solar is highly correlated with demand within days, but not over seasons. Seasonality is so strong that demand and solar generation are negatively correlated in France. Wind in-feed is highly correlated between countries, and even more so if correlations are not calculated from hourly values, but longer time periods. Wind and solar generation are negatively correlated. For an example of generation profiles see Figure A2.

Table 5: Coefficients of correlation between hourly wind profiles, solar profiles, and demand in different countries (2006-11).

	wGER	wFRA	wNLD	wPOL	sGER	sFRA	dGER	dFRA
wGER	1							
wFRA	.44	1						
wNLD	.84	.49	1					
wPOL	.61	.18	.39	1				
sGER	-.12	-.14	-.13	-.12	1			
sFRA	-.08	-.13	-.10	-.08	.95	1		
dGER	.19	.14	.18	.16	.21	.25	1	
dFRA	.14	.17	.16	.18	-.10	-.07	.70	1

Fixed and variable generation costs are listed in Table 6. Availability is 0.8 for all technologies. Summer 2010 NTC values from ENTSO-E were used to limit transmission constraints. CHP capacity and generation is from Eurelectric (2011b). An interest rate of 7% was used for all investments, including transmission and storage and vRES. Transmission investment costs are one million Euro per GW NTC capacity and km both for AC and DC lines. Screening curves and full cost curves of these technologies are displayed in Figure A3.

Table 6: Cost parameters of generation technologies.

			investment costs (€/KW)	quasi-fixed costs (€/KW*a)	variable costs (€/MWh$_e$)	fuel costs (€/MWht)	CO_2 intensity (t/MWht)	efficiency (1)
Dispatchable		Nuclear*	3500	40	2	3	-	0.33
	CHP Technologies	Lignite*	2200	30	1	3	0.45	0.38
		Lignite CCS*	3500	140	2	3	0.05	0.35
		Hard Coal*	1500	25	1	12	0.32	0.39
		CCGT	1000	12	2	25	0.27	0.48
		OCGT**	600	7	2	50	0.27	0.30
		Load shedding	-	-	-	***1000	-	1
vRES		Wind	1300	25	-	-	-	1
		Solar	2000	15	-	-	-	1
		Pump Hydro**	1500	15	-	-	-	0.70

Nuclear plants are assumed to have a life-time of 50 years, all other plants of 25 years. OCGT fuel costs are higher due to structuring costs. Lignite costs include mining.
* Base-load plants run even if the electricity price is below their variable costs (run-through premium).
**Flexible technologies are assumed to earn 30% of their investment cost from other markets (e.g. regulating power).
***This can be interpreted as the value of lost load (VOLL).

4.7 Back-Testing

The model has been back-tested with historical data. Using real 2008-10 capacity and demand data as well as fuel and CO_2 prices, value factors were estimated, which are compared to historical market data in table 6. Wind value factors are replicated very well, while modeled solar value factors are somewhat too low, most probably due to the very stylized merit-order curve with only few technologies. Crucial features of electricity prices such as average prices as well as peak and off-peak prices can be fairly well replicated, as shown in Figure 2a and 2b.

Table 6: Value factors in Germany

	Wind		Solar	
	model	market	model	market
2008	0.93	0.90	1.04	1.25
2009	0.95	0.91	1.03	1.14
2010	0.94	0.94	0.98	1.11

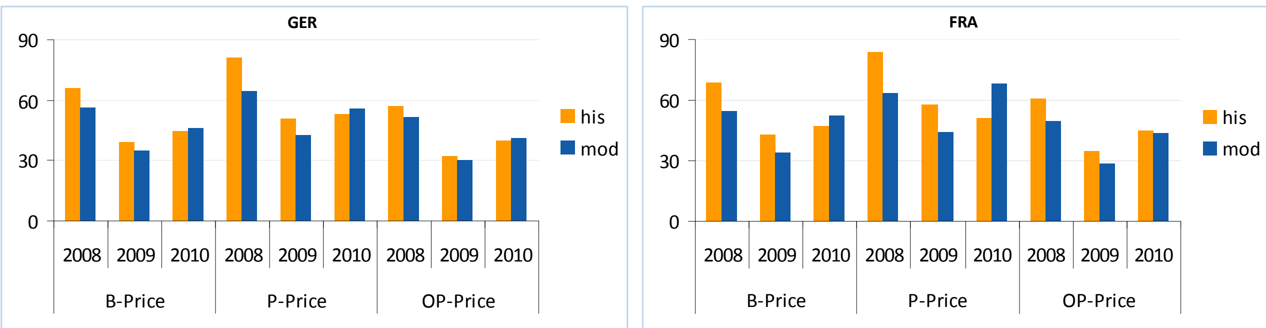

Figure 2a and 2b: Base, peak, and off-peak prices for Germany and France in €/MWh. Comparison of historical spot day-ahead prices (orange) with model output (blue).

5. Results

The model introduced in section 4 is now used to estimate revenues and value factors. The first set of runs is based on best-guess long-term ("benchmark") assumptions regarding energy system parameters. These parameters are then systematically varied to understand their impact on the market value of vRES. The benchmark assumptions are:

- CO_2 price of 20 €/t
- hard coal price of 12 €/MWh (130 €/t) and gas price of 24 €/MWh
- interconnectors have today's NTC values (endogenous investment is possible)
- today's amount of pump hydro storage is available (endogenous investment is possible)
- ancillary service and CHP must-run constraints hold
- the current plant stack is in place (endogenous investment is possible)
- all generation technologies are available for new investments

For this set of assumptions (and each set of changed assumptions) several model runs were conducted, with the share of wind power in total electricity generation exogenously varied between zero and 30%, corresponding e.g. to 80 GW installed capacity in Germany.[9] Unlike in several other studies, no specific future years are modeled and no evolution of value factors over time is estimated. It is not the intention to make projections of value factors, but to understand what which factors affect them. Thus, value factors at different wind penetration rates and with changed system parameters are compares to the case without wind power and at benchmark parameters. This setup could be called a two-dimensional comparative statics approach, since both the wind market share and a second parameter are changed simultaneously. Results will be mostly presented as "value factor curves" that show the value factor as a function market share. Due to space constraints, most results are reported for German wind power only; results for solar power and other countries are available upon request.

5.1 Benchmark

With little wind power installed, the value factor is about 1.06, implying that the first wind turbine would have earned more than the base price (Figure 3). In other words, the correlation effect increases the value of wind power by six percent. With higher penetration rates it drops quickly to 0.9 at 10% market share and slightly above 0.5 at 30% market share.[10] This is the merit-order effect at work. In other words, for wind power to become competitive at this scale, costs have to decrease 2 times more than studies suggest that compare costs to the base price (EPIA 2011, BSW 2011).

The base price is also reduced, falling from 50 €/MWh to 40 €/MWh as wind penetration grows to 30% (Figure 3). As implied by the decreasing value factor, revenues of wind generators fall quicker, from 55 €/MWh to 20 €/MWh. The dotted line gives a very rough idea of the cost development of wind power under learning. Assuming optimistically today's onshore wind LCOE in Germany to be 70 €/MWh, the global learning rate to be 5%, and global capacity to grow twice as fast as European capacity, the LCOE would drop to 60 €/MWh at 30% market share. The model results indicate that falling revenues overcompensate for falling costs: the gap between costs and revenues remains open, and indeed increases. Costs would need to drop to 40 €/MWh to allow 15% market share without

[9] Nitsch et al. (2010) project the wind market share to reach 60% in Germany by 2050 and EC (2011) a RES share of 25-50% in Europe.

[10] The value factors at 7% market share are slightly above 0.8, while both market data and model back-testing reported value factors above 0.9. This is because here the same penetration rates in all countries have been assumed, while actually there was relatively less wind outside Germany.

subsidies and to 30 €/MWh for 20%. From a different perspective, with a value factor of 0.5 and LCOE of 60 €/MWh, the base price has to be above 120 €/MWh to make 30% wind competitive. These results imply that at 30% wind share, subsidies would be about € 6 billion per year in Germany with learning and € 8 billion without learning under benchmark assumptions. Still another way of looking the price effect is comparing price duration curves and generation profiles at low and high penetration rate (Figure A4).

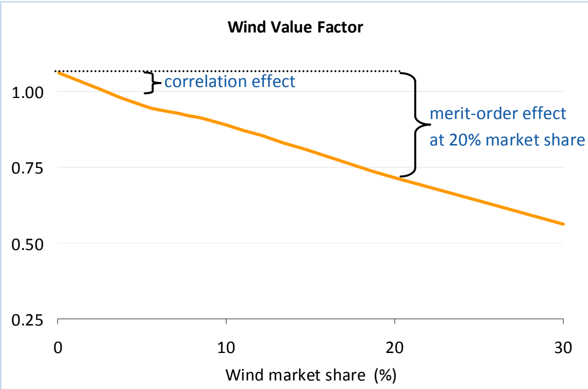

Figure 3: Value factor of wind under benchmark assumptions.

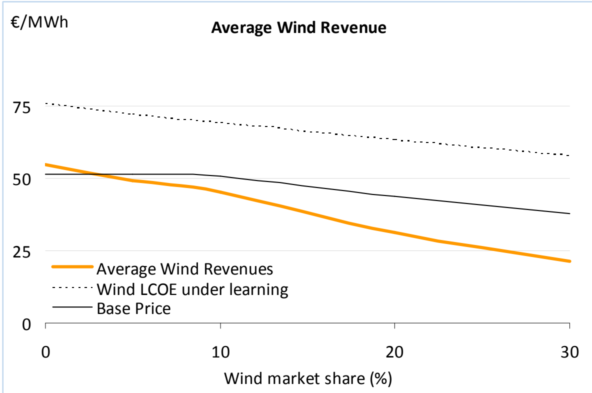

Figure 4: Average specific revenue of wind (orange), base price (black), LCOE of onshore wind power (dotted) under benchmark assumption and a learning rate of 5%.

Figure 5 shows how the capacity mix evolves as more wind power is pushed into the market. At a 30% share, equivalent to an additional 80 GW of wind power, total dispatchable capacity is reduced only slightly, from 100 GW to 90 GW. Nuclear, lignite, and hard coal are reduced while gas capacity remains constant. This relative shift from base load to peak load technologies is a standard finding of the literature. Remarkably, there is no investment in storage. Figure 6 shows which fuel is the price setter during how much time of the year. One can see how the share of low-variable cost dispatchable technologies such as lignite and nuclear increases with higher wind deployment, the reason being that residual load is often reduced enough to make these technologies price setting. At 30% the price drops to zero during 1000 hours of the year, when must-run generation becomes price-setting.

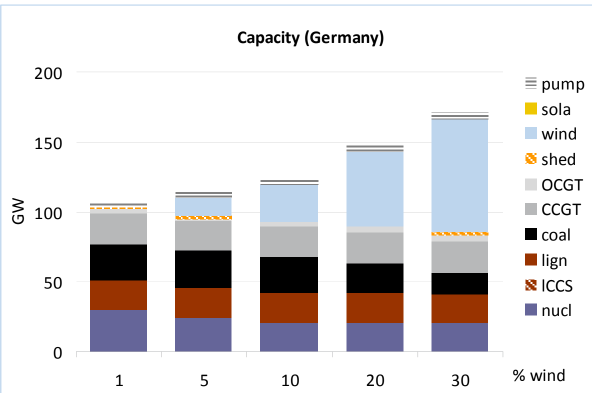

Figure 5: Capacity development for given wind capacity.

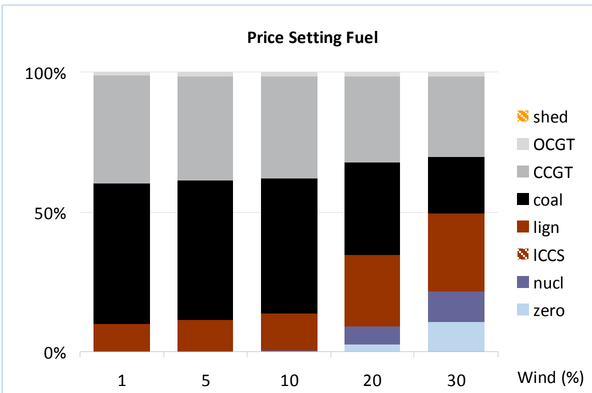

Figure 6: Price-setting technology as a share of all hours.

Figure 7 presents wind value factors for the other countries. While countries with flatter generation profiles and a flatter merit-order curve (The Netherlands) have slightly higher value factors at high penetration rates, countries with a steep merit-order curve due to high nuclear capacity (France) experience a faster drop. Overall, the pattern does not differ significantly across space. In different years, wind generation is differently correlated with other parameters, changing its market value. However, value factors are virtually unaffected if different historical wind profiles are used (Figure 8).

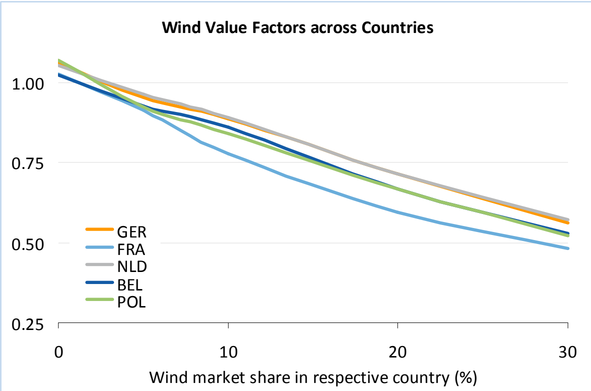

Figure 7: Wind value factors across countries.

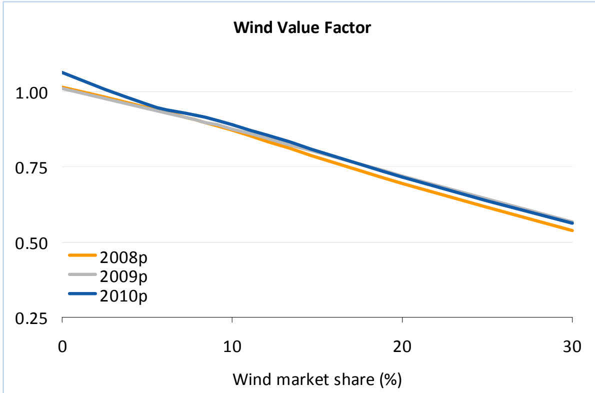

Figure 8: Wind value factors for different wind years.

In a different set of runs, the solar market share was varied between zero and 15% while the wind share was kept at zero. The model results indicate that the merit-order effect hits solar power as much as wind power. The value factor actually drops to 0.5 already at 15% market share (Figure 9). Thus is insofar surprising as solar generation is quite well correlated with demand. While solar generation is quite well correlated with demand, it is also more "peaky" than wind, with a lot of generation concentrated in few hours. In these hours, residual load is reduced to very low levels even though demand is high, leading to a steep value factor curve. These findings are consistent with Gowrisankaran et al. (2011), Nicolosi & Nabe (2011), and Borenstein (2008), but market data have shown higher solar value factors at low penetration levels (section 3). Solar power is often reported to experience a steeper learning curve than wind power. But even at a learning rate of 10% and a global growth rate four times as high as in Europe, at 15% market share solar LCOE are far above spot market revenues (Figure 10). Subsidies for solar would be € 7 billion per year in Germany with learning and € 15 billion without learning.

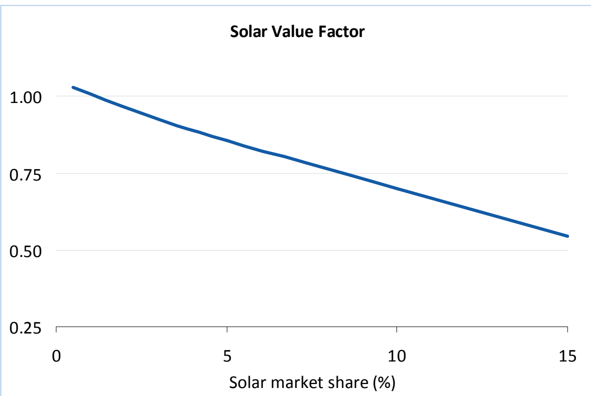

Figure 9: Value factor of wind in the benchmark run.

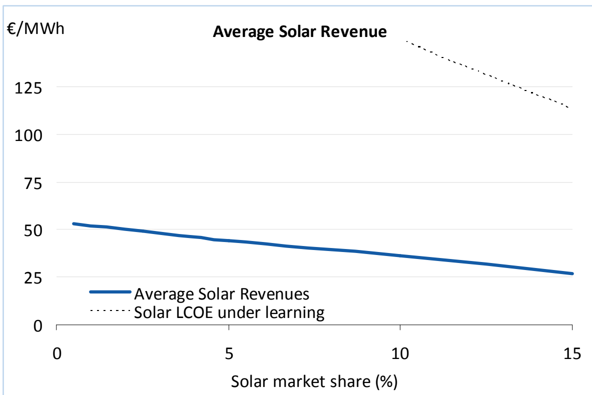

Figure 10: Average revenue of solar in the benchmark run (blue), base price (grey), LCOE of onshore wind power (dotted) at a learning rate of 10%.

If both wind and solar power are introduced simultaneously, the respective value shares drop faster. However, 20% wind combined with 10% solar results in a higher wind value factor than 30% wind (Figure 11). These results indicate that notwithstanding wind speeds and solar radiation being negatively correlated, an energy system with large shares of both vRES technologies leads to low value factors for both of them. Long-term targets for wind power are often considerably higher than 30%. Very high vRES shares might induce significant technological change that might render model assumptions invalid. If the assumptions remain valid however, the wind value factor drops to 0.3 at 75% market share and the solar factor to 0.2 at 40% (Figure 12). Installed wind capacity would be so high that a third of generation is curtailed, contributing significantly to the low value factor.

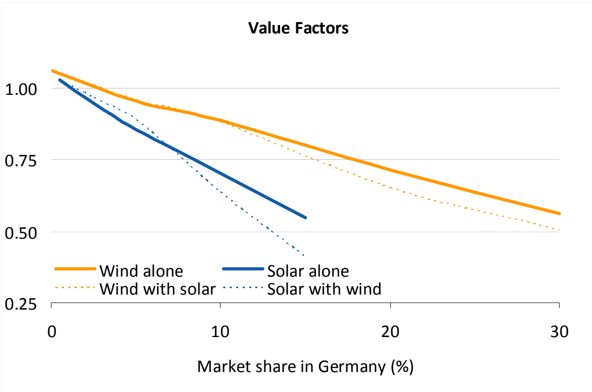

Figure 11: Wind and solar value factors when employed simultaneously

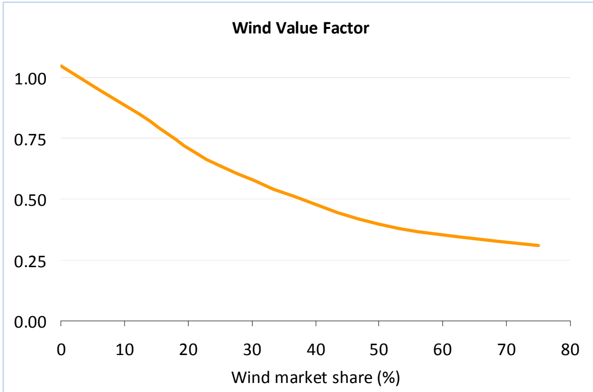

Figure 12: Wind value factor at very high penetration rates.

In the following paragraphs, the benchmark assumptions are changed step by step to assess the impact that individual factors have on the market value of vRES.

5.2 The effect of CO_2 pricing

One of the main drivers of change in the European electricity system during the last years has been CO_2 pricing. Higher carbon prices imply higher variable costs for fossil plants and thus higher electricity prices. But they also trigger investments in low-carbon technologies such as nuclear power or CCS, which have low variable cost, making the merit-order curve steeper and thus result in low prices especially during windy hours. Thus a priori it is not obvious if a higher CO_2 price is beneficial for wind generators. Here, the benchmark price of 20 €/t was changed to 0 €/t and 75 €/t. Interestingly, both higher and lower CO_2 prices reduce the value factor (Figure 13). With a low CO_2 price, the merit-order curve becomes steeper in the range of lignite-hard coal-CCGT due to CO_2 intensities, which is further enforced by lignite investments. At a high price, in contrast, new investment in nuclear power is triggered which also makes the merit-order curve steeper. The lower value factor over-compensates the base price-increasing effect of CO_2 pricing at intermediate wind penetration rates: Wind revenues are actually lower at 75 €/t CO_2 than at 20 €/t. In economic terms, an increase in the input price of a number of competitors of wind power has resulted in lower revenues, which seems counterintuitive at first glance. The reason for this is investment in nuclear power, which can be understood as a closer substitute to emitting generators than wind power.

This finding depends crucial on new investments in nuclear or CCS. If those technologies are phased out and are not available for new investments e.g. due to security concerns or lacking acceptance, the outcome is very different. The merit-order becomes so flat that the price seldom drops below the variable costs of hard coal. That is reflected in the wind value factor, which remains around 0.8 even at 30% market share (Figure 14). As a matter of fact, at a learning rate of 5%, wind power levelized costs would drop to around 60 €/MWh well below revenues of 80 €/MWh, meaning that more than 30% of wind power would be competitive in Germany. However, excluding nuclear power and CCS results in a dramatic increase of carbon emissions: While a CO_2 price of 75 €/t brings down emissions from 700 Mt to 200 Mt per year, emissions increase to more than 700 Mt even at 30% wind market share. In other words, excluding nuclear and CCS from the set of possible technologies helps wind power to become competitive, but leads to dramatically higher CO_2 emissions.

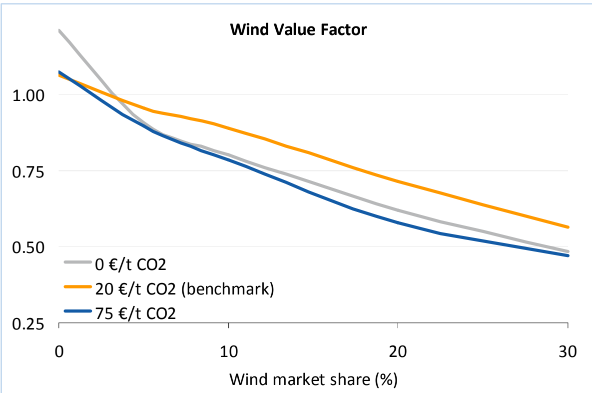

Figure 13: The value factor under different CO_2 prices. Investments in lignite (low carbon price) or in nuclear (high carbon price) reduce the value factor

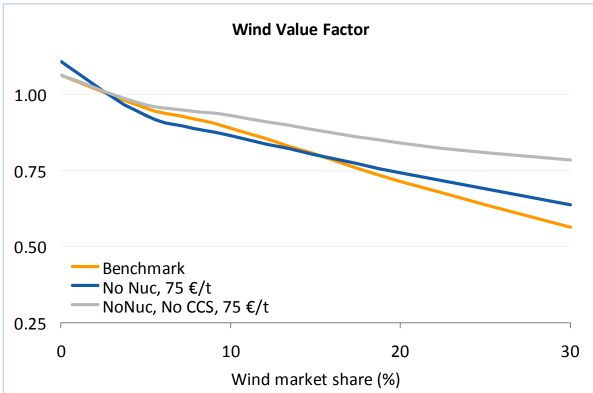

Figure 14: The wind value factor without low-carbon technologies. Ruling both options out increases the value factor by up to 0.2 at high carbon prices.

5.3 The effect of fuel prices

For the benchmark runs, fuel prices of 12 €/MWht for hard coal and 24 €/MWht for CCGTs were assumed. While fuel analysts often argue that for the foreseeable future sufficient coal and gas resources are available at long-run marginal costs around these numbers, many studies on the electricity system assume higher fuel prices. To understand the influence of fuel prices, gas and coal prices were doubled separately and simultaneously. A plausible expectation is that higher fuel costs, driving up the electricity price, increase the revenues of wind power. The opposite is the case: at intermediate wind penetration rates increasing fuel prices *reduces* the revenues for wind power (Figure 16). The driver behind these results is again investment in substitute generation technologies, in this case lignite and nuclear, which in turn makes the merit-order curve steeper. While higher fuel prices increase the base price by almost ten percent on average, the dropping value factor (Figure 15) leads to reduced or only slightly increased revenues for wind power. These results indicate that it is not necessarily the case that vRES benefit from higher fuel prices, indeed they might even loose.

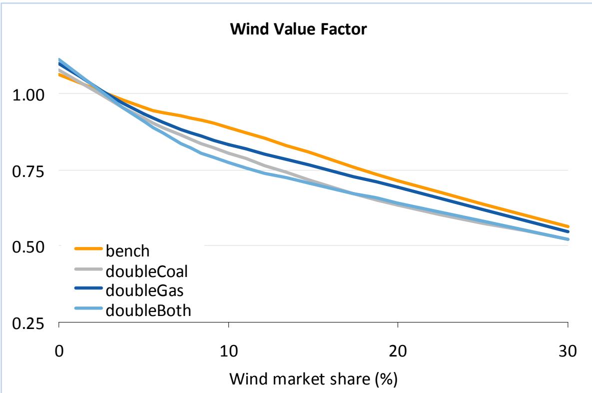

Figure 15: Wind value factors at various fuel prices.

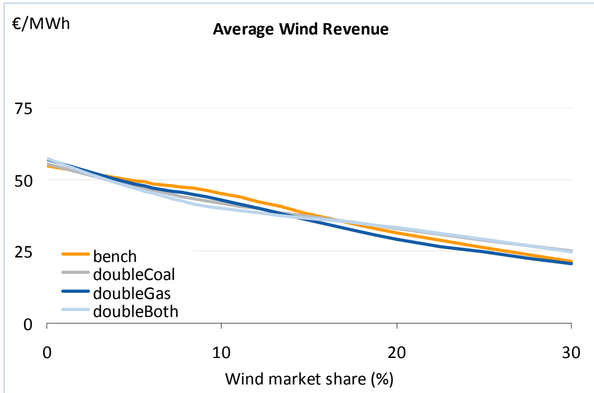

Figure 16: Absolute wind revenues at various fuel prices.

5.4 The effect of interconnector capacity

It is often suggested that higher long-distance transmission capacity helps variable renewables by smoothing out fluctuations across space. Given the attention that transmission expansion receives in the public and academic debate, one could expect the impact of more transmission capacity on wind income to be positive and significant. Recall that in the model, cross-border flows between market areas are limited by NTCs while there are no transmission constraints within countries. To test the effect of interconnector expansion on market values, NTC values were doubled, and set to zero and infinity.

Model results indicate that the impact of more cross-border transmission capacity on wind revenues in Germany is very small and sometimes even negative (Figure 17). This can be explained by two effects that work in the opposite direction: on the one hand, more transmission capacity indeed helps smoothing out fluctuations. On the other hand, in France prices are often set by nuclear power during windy hours at high wind penetration rates. Since French and German winds are well correlated, during windy hours French nuclear power becomes price setting in Germany – the more often the more interconnector capacity is available. In France both effects work in the same direction: increasing transmission capacity helps not only smoothing out wind, but reduces the number of hours when French wind is locked in with low prices set by nuclear. The French wind value factor is 10-15 percentage points higher at double NTC capacity compared to zero capacity (Figure 18). On European average, the wind value factor increases by 5 percentage points when moving from zero to double NTC.

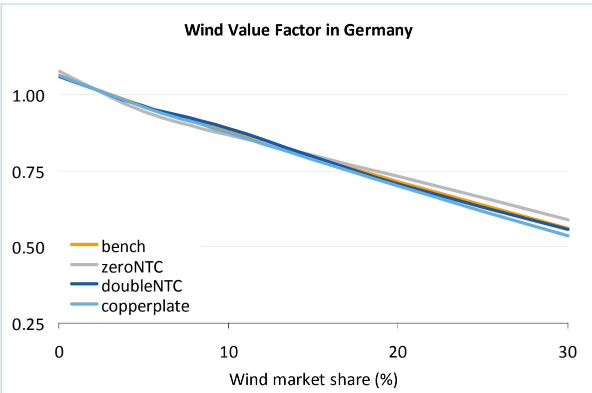

Figure 17: The German wind value factor remains unaffected by higher transmission capacity.

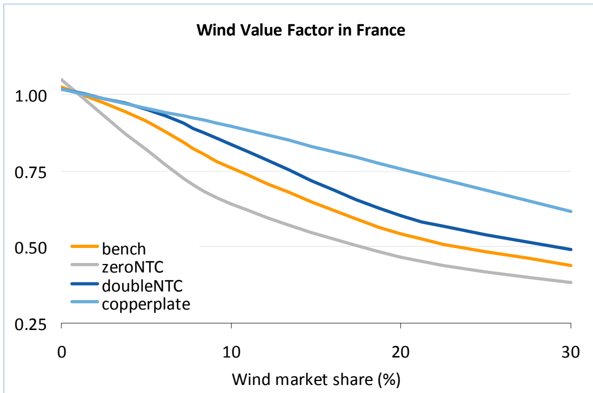

Figure 18: The French wind value factor benefits strongly from higher interconnector capacity.

5.5 The effect of storage

Electricity storage is often mentioned as a way to level out fluctuation electricity generation from vRES. While this is of course in principle correct, it is not well understood how much and what kind of storage is needed. To understand the effect of storage, the existing pump hydro storage capacities are doubled and set to zero. The effect on wind is very limited: Adding 56 GWh storage capacity to the system increases its value factor by merely one percentage point. The reason, besides the limited size of additional storage compared to wind capacities, is that pump hydro is often designed to fill the reservoir in about eight hours while wind fluctuations occur rather on the scale of weeks. Solar power with pronounced diurnal pattern can benefit much more from additional pump hydro storage and increases its value factor by up to five percentage points. These results indicate that different vRES technologies might benefit from different storage technologies and that wind power needs something more long-term than pump hydro.

5.6 The effect of flexible conventional generators

Even if power plants were perfectly flexible, the upward-sloping merit order would cause the wind value factor to decrease with higher penetration rate. This is amplified by inflexibilities in the power system that force generators to produce even if the price is below their marginal costs ("must-run generators"). In the present model, three linear constraints are meant to capture these inflexibilities: the ancillary service requirement, the CHP must-run constraint, and the run-through premium. The former is meant to represent the provision of ancillary services such as regulating power or voltage support. In each country, conventional generators with a capacity of 20% of annual peak load have to be online at any point in time. Thus if residual remand drops below this threshold, the price falls to zero and vRES generation is curtailed. In the long term, one can think of alternative providers of these ancillary services, e.g. phase-shift transformers, electronics, batteries, or demand response. To test the potential impact of such a technological development on wind revenues, the ancillary service requirement is set to zero. CHP generators produce heat and electricity simultaneously. Heat has to be provided when it is demanded, meaning that CHP plants become must-run units during cold times. They can be made more flexible by installing heat storages that uncouple heat generation from heat consumption. To test the impact of such a measure, it has been assumed that all CHP plants can be dispatched freely, just like a condensing plant. The run-through premium is meant to capture start-up costs and minimum load constraints of thermal plants. Nuclear, lignite, and hard coal plants are bidding below their variable costs to avoid the costs related to shut-down. Technical progress at the plant level can reduce these costs, which is modeled here as setting the premium to zero. Setting these constraints to zero is obviously a very drastic assumption, thus results should be understood as the upper bound that additional system flexibility can deliver.

Relaxing the spinning reserve requirement has a small, relaxing the run-through premium a large, and relaxing the CHP constraint a very large impact. Relaxing the latter constraint alone increases the value factor by 0.15 at high wind levels. Taking away all three constraints increases the value factor at high wind penetration by half from 0.5 to 0.75, which is the highest impact of all tested factors (Figure 19). The number of hours when base load or must-run units set the price is reduced from 50% to 20% (Figure 20). In countries with little CHP capacity and much Baseload capacity such as France, the run-though premium's impact is larger than the CHP constraint's. While one needs to keep in mind that in this modeling setup complex technical constraints were implemented as simple linear parameterizations, this indicates how important power system flexibility is to integrate vRES. Furthermore, flexibility can provide further benefits to balance forecast errors and tends to be underrated in the present deterministic model framework.

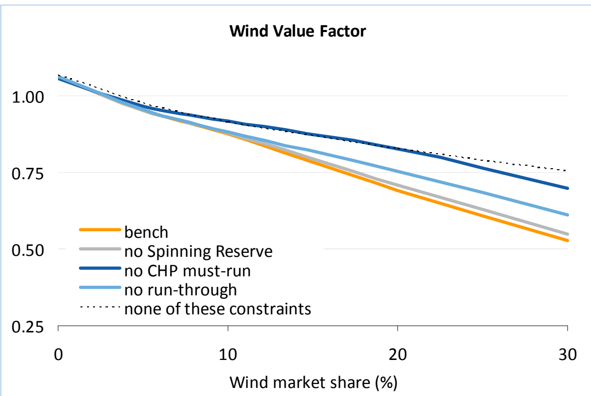

Figure 19: Wind value factor without the CHP constraint, the ancillary service must-run requirement, and the run-through premium. Relaxing these constraints has a very large positive effect on wind power's market value.

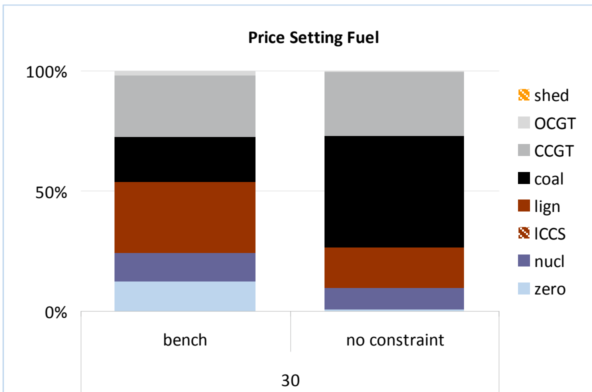

Figure 20: Price setting fuel at 30% wind share with and without inflexibilities: Zero prices disappear and base load technologies set the price much less often.

5.7 The long-run equilibrium

Up to this point, the existing generation capacity was taken as given, but decommissioning as well as investment was possible, similar to the approach by Nicolosi & Nabe (2011). In economic terms, this can be labeled a “mid-term” perspective, as done by MacCormack et al. (2010). The mid-term can be understood as the time frame following a shock to the system but before the existing capital stock has fully adjusted to the new long-term equilibrium. Shocks in this sense are both the introduction of additional wind power as well as changing benchmark parameters. In the “short-term”, changes to the existing capacities are not allowed. Thus the model reduces to a pure dispatch model. In a “long-term” view, existing plants have passed their technical life-time and are decommissioned, and all capacity is due to an endogenous investment decision. The outcome of such a long-term analysis is the long-run market equilibrium, where all generators earn their market-rate of return and there are no profits (Steiner 1957, Boiteux 1960, Crew et al. 1995, Hirth & Ueckerdt 2011). Numerical long-term models are discussed in Lamont (2008), Bushnell (2010), Mills (2011), and Green & Vasilakos (2011). The following figures contrast the results from a mid-term (benchmark) run with those in the long-term equilibrium.

In the long-run, without sunk investments, the electricity system is more flexible. Since wind power is exogenous to the model, the long-term runs produce capacity mixes that “fit” best to a certain wind market share. That results in higher revenues for wind power, since the system is not locked in with too high amounts of base-load technologies. This effect can be seen most clearly in France, where today there are large amounts of sunk nuclear investments. In the long-run equilibrium the value factor is 10 percentage points higher at 30% market share than in the medium run (Figure 21). The long-run features much less nuclear capacity and more mid-merit and peaking plants (Figure 22). However, even in the long run the value factor drops quite dramatically with high wind penetration.

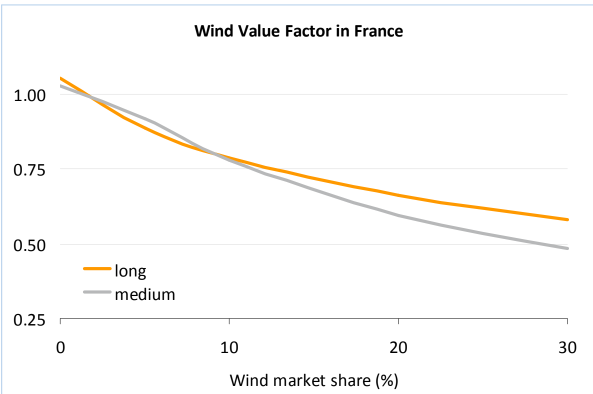

Figure 21: Value factors with the existing plant stack (medium) and without (long).

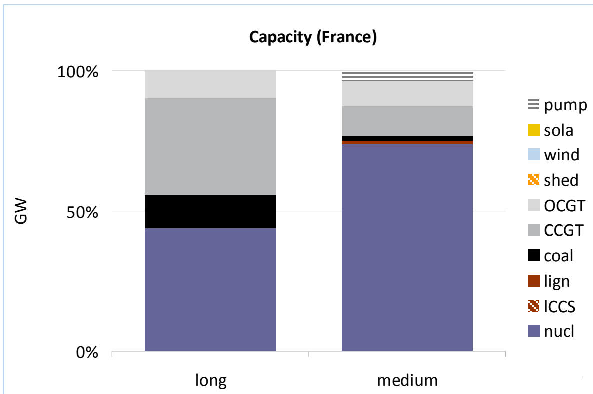

Figure 22: Capacity mix at 30% wind power. The long-term equilibrium capacity mix has larger shares of mid- and peak load technologies.

6. Discussion

Table 5 presents an overview of all parameter changes from section 4 and lists the major causal chains. Quite often direct effects are counterbalanced by new generation investments.

Table 5: Divers of wind value factors

Change	Value factor	Chains of Causality
CO_2 price ↓	↓	steeper merit-order curve in the range lignite – hard coal – CCGT
CO_2 price ↑	↓	steeper merit-order curve due to new investments in low-carbon low-variable costs technologies like nuclear or CCS
Coal price ↑	↓	flatter merit-order curve due to higher variable costs of coal in the range hard coal – CCGT; lignite and nuclear investments overcompensate
Gas price ↑	↓	steeper merit-order curve due to higher variable costs of gas; nuclear, lignite and hard coal investments aggravate this effect
Interconnector Capacity ↑	–	smoothening out of wind generation across space; counterbalanced by French nuclear becoming price setting in Germany
Storage capacity ↑	↑/–	levels out electricity prices, but very small impact: one percentage point when doubling pump hydro storage capacities; large impact on solar
Flexibility ↑	↑	reduced must-run generation and run-through premiums lead to higher prices especially during hours of high wind supply; very large impact

Note that the effect on value factors is sometimes different at different penetration rates. The dominant effect is discussed here.

Figure 17 presents a graphical summary of all model runs. The resulting family of value factor curves can be interpreted as the probable range of value factors for a given market share, indicating the range of uncertainty that is introduced by uncertainty about energy system parameters. The model suggests that the wind value factor is between 0.35- 0.75 at 30% market share, with a benchmark point estimate of about 0.5. In addition, historical values and the line implied by the regression analysis are added. Historical values are well in the range of estimates, while the econometric result indicates a slower decrease of the value factor than the fundamental model, probably explained by the linear specification of the regression, limited variation in observations, and the trade effect.

The estimations of wind value factors are consistent with most of the literature that models investment endogenous (Lamont 2008, Mills 2011, Nicolosi & Nabe 2001). Also, other findings are consistent with the existing literature, such as the wind value factor being above unity at low penetration levels (Sensfuß 2007, Obersteiner & Saguan 2010, Energy Brainpool 2011, Mills 2011) and the solar value factor to be higher at low penetration levels, but drop quicker than wind with growing market shares (Lamont 2008, Gowrisankaran et al. 2011, Mills 2011, Nicolosi & Nabe 2011). The effects of parameter changes to the energy system are generally not discussed in the literature, such that comparison is not possible.

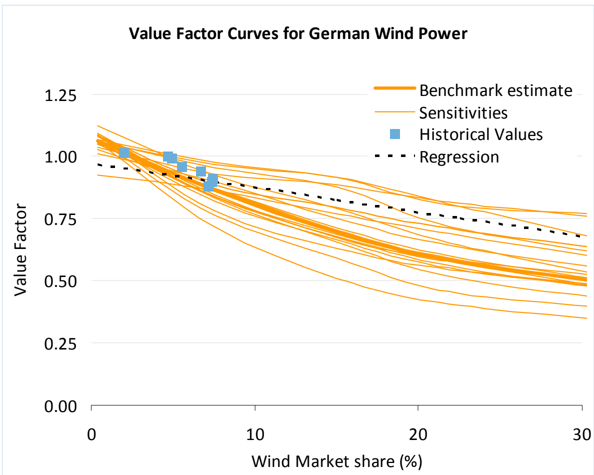

Figure 23: Wind value factor curves of all model runs and historical values. The value factor is expected to fall to 0.4 to 0.7 at 30% wind market share.

At an abstract level, three perspectives offer three different and complementary interpretations of these results. A modeler might note that the value factor is a function of i) installed wind capacity, ii) the slope of the merit-order curve, and iii) intertemporal flexibility of the power system provided by e.g. hydro power: the more wind power and the steeper the merit-order curve, the smaller the value factor, and the more hydro power the close the value factor to unity. From an engineering view, the low value factors reflect the physical and technical difficulties to store electricity. From an economics perspective, different generation technologies are imperfect substitutes to produce electricity. Dispatchable plants are imperfectly substitutable because they differ in their fix-to-variable cost ratios, and fluctuating renewables are imperfect substitutes because of their exogenous generation profile. The value factor is the relative price of one technology to another. Increasing wind supply reduces its price relative to its imperfect substitutes, just as the relative price of any good or factor is reduced as its supply rises.

7. Conclusions

Electricity systems with limited intertemporal flexibility provide a frosty environment for low-marginal-cost variable renewables like wind and solar power. If significant vRES capacity is installed, the merit-order effect depresses the electricity price whenever the primary energy source is available. This merit-order effect reduces the valance of wind and solar power. While today in Germany, wind power has a relative price of more than 0.9 of the base price, this value factor is estimated to drop to 0.5 as the wind market share grows to 30%. The solar value factor is estimated to drop even quicker, from 1.1 to 0.5 already at 15% market share. This means that at a base price of 50 €/MWh wind LCOE need to fall from around 70 €/MWh today to 25 €/MWh to make 30% wind penetration competitive, or the base price would need to increase to 140 €/MWh with unchanged wind LCOE to make wind competitive at this penetration rate.

Several factors have been identified that significantly impact the value factors of solar and wind power. The three most important drivers seem to be a) the CO_2 price in combination with availability of low-carbon low-variable-cost dispatchable technologies (nuclear and CCS), b) long-distance interconnections, and c) the flexibility of must-run generators, especially CHP plants. Fuel prices and additional storage capacity have only limited effects on wind, but storage does increase the value of solar. On average, wind benefits from interconnector expansion, but gains are very unevenly distributed across space – in some markets wind revenues even fall with higher interconnector capacity. Usually these shocks work through a variety of channels and interact with the power system, often leading to surprising results. Thus there is a clear conclusion regarding methodology: To evaluate long-term effects of policies or price shocks, one needs to model prices and investment endogenously.

While price and policy uncertainty leads to a wide range of outcomes, the value factor drops significantly even under very favorable assumptions. In the long run, when all capacity is endogenous and the electricity system has additional degrees of freedom to integrate vRES, the value factor drops only to 0.6. Under certain parameter combination, it remains around 0.75 at 30% market share – but even that is a significant drop.

While keeping methodological shortcomings such as the lack of hydro modeling in mind, several policy conclusions can be drawn from these results. First, increasing the flexibility of the system through demand response, transmission investments and relaxed constraints on conventional generators should be a top priority for research, engineering, and policy. Results presented here indicate that making CHP generators more flexible could be a relative quick win. Second, at today's electricity system parameters and prices, wind and solar power will have a very hard time to become competitive on the market on large scale, even with quite steep learning curves. Research as well as policy should take the possibility of a limited role for solar and wind power into account. Finally, the results indicate how important it is to develop alternative low-carbon electricity sources to reach ambitious climate and renewable targets. This includes dispatchable generation, but also variable sources that are negatively correlated with wind and solar power.

The work presented here could be extended in several directions. One topic of future research is the second important factor that determines the market value of renewables: imbalance costs. Another topic could be a more thorough evaluation of specific flexibility options, including specific storage technologies, demand side management, long-distance interconnections, and heat storage on the supply as well as the demand side. Special focus should be paid to the existing hydro reservoirs in Scandinavia, France, and the Alps. A different project would be to translate the finding from this work to optimal shares of vRES under different parameters. While assessing imbalance costs demands stochastic modeling, an assessment of flexibility options and of optimal vRES shares could rely on a similar methodology as this paper.

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9. Appendix

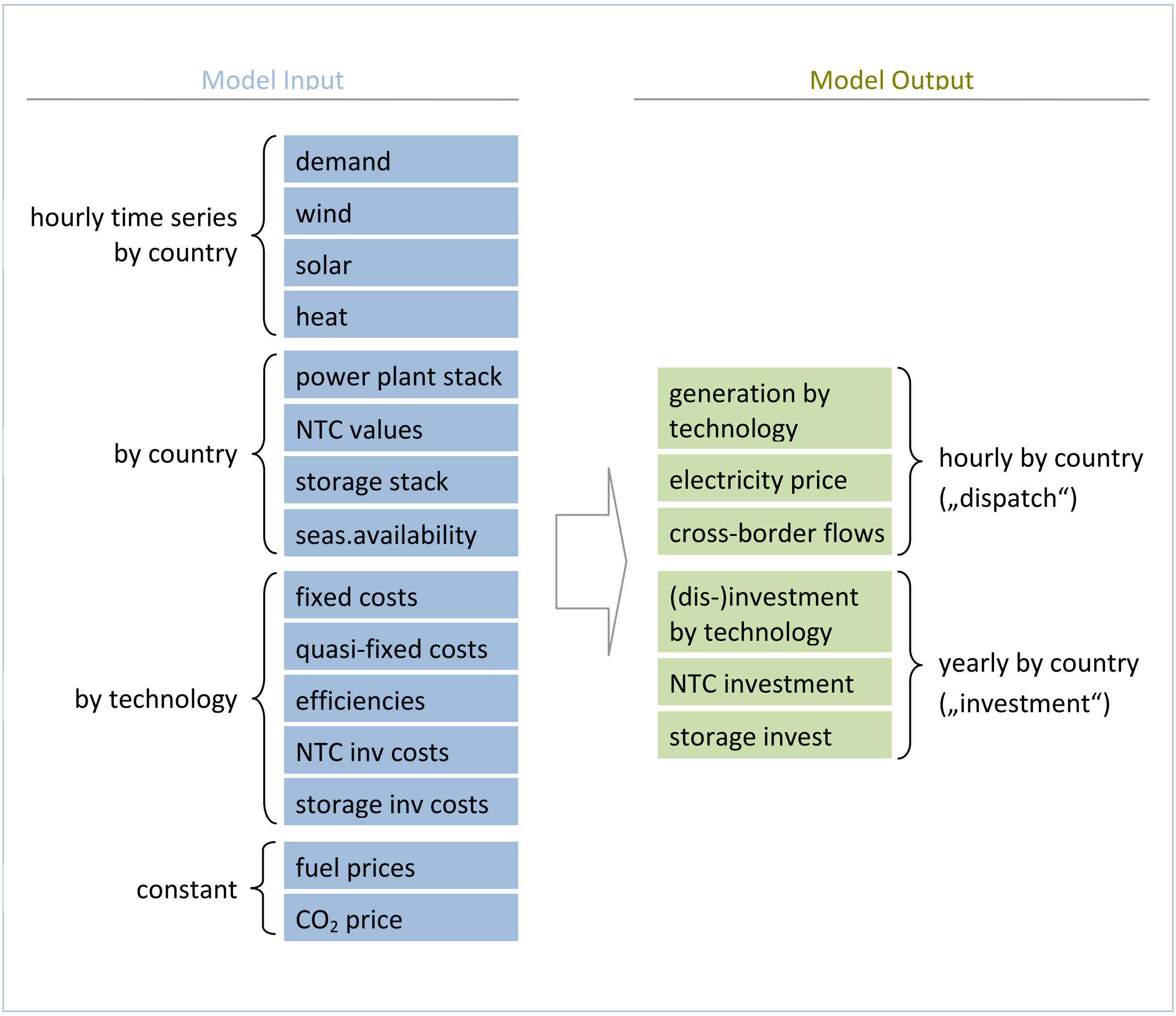


Figure A1: Graphical representation of the model.

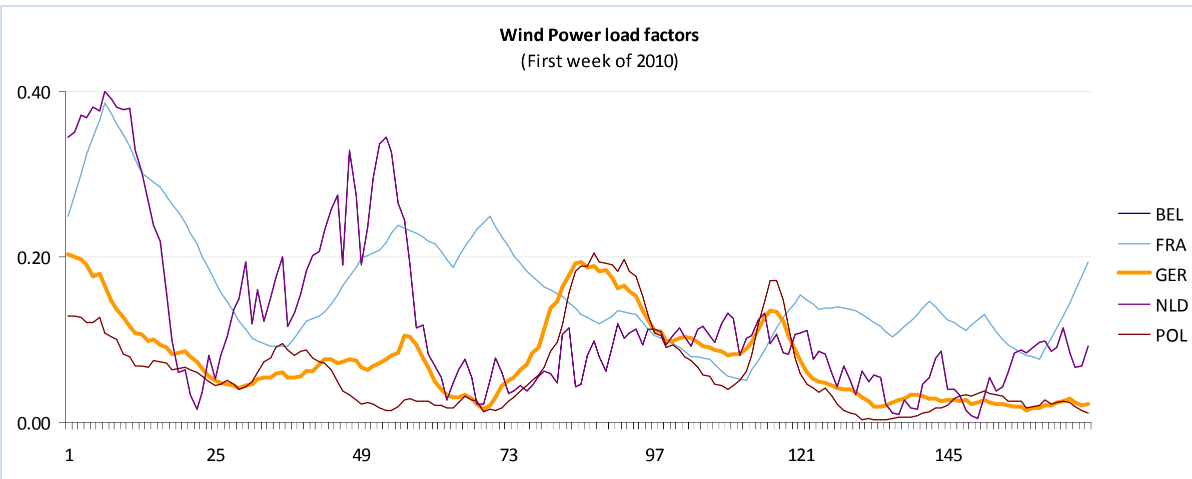


Figure A2: The wind profile for several countries.

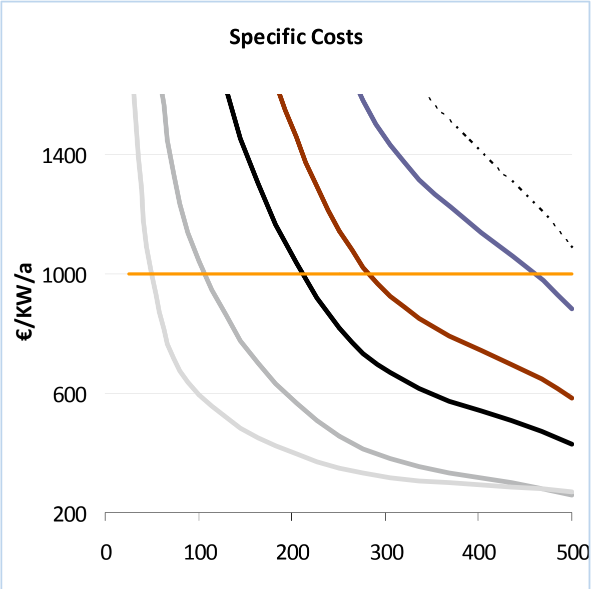


Figure A3a: LCOE of all technologies (peak load) as a function of FLH. Load shedding is the cheapest technology for up to 80 FLH.

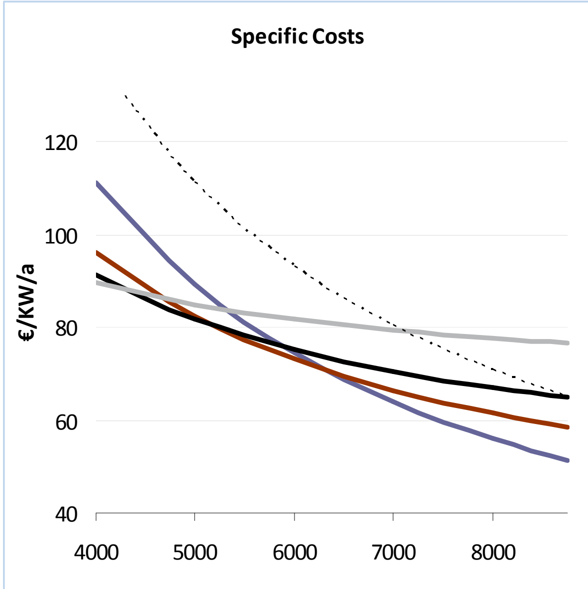


Figure A3b: LCOE of all technologies (mid and base load) as a function of FLH.

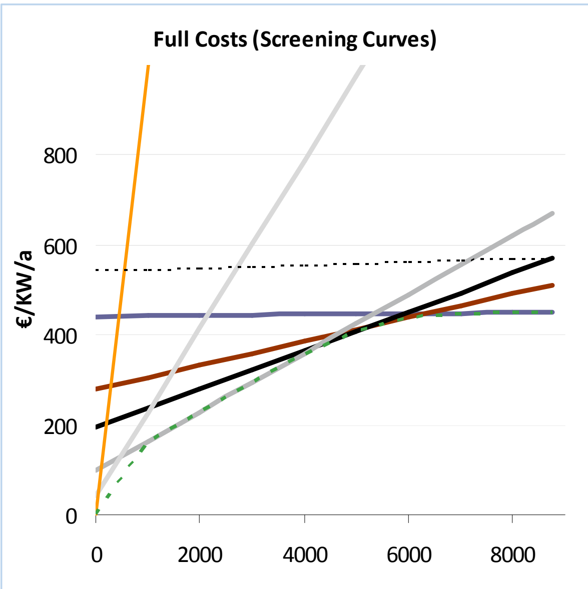
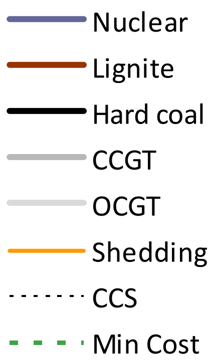
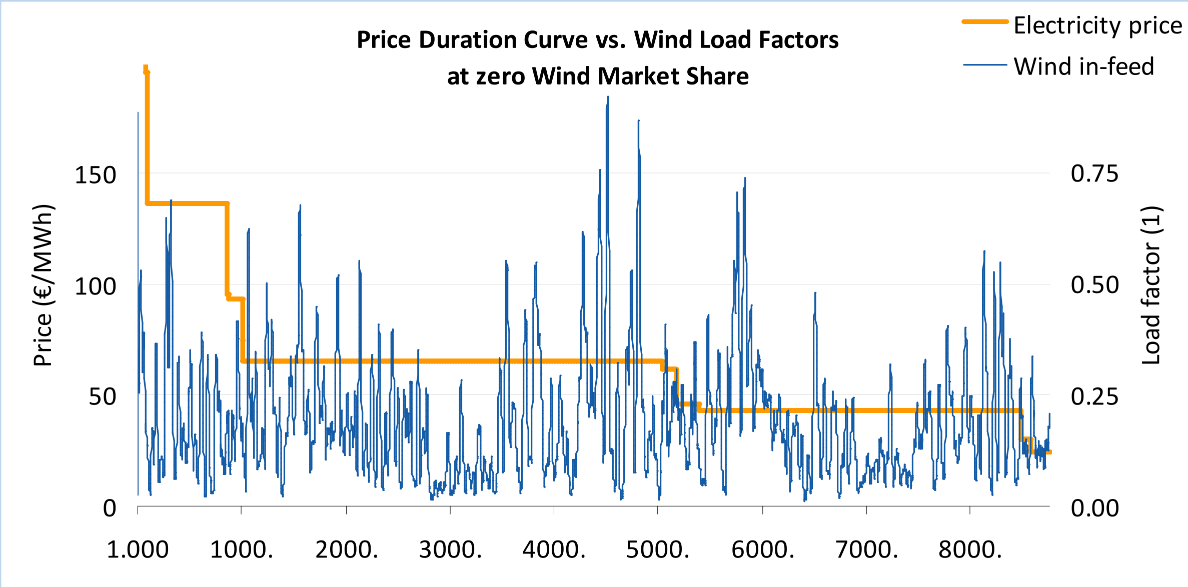
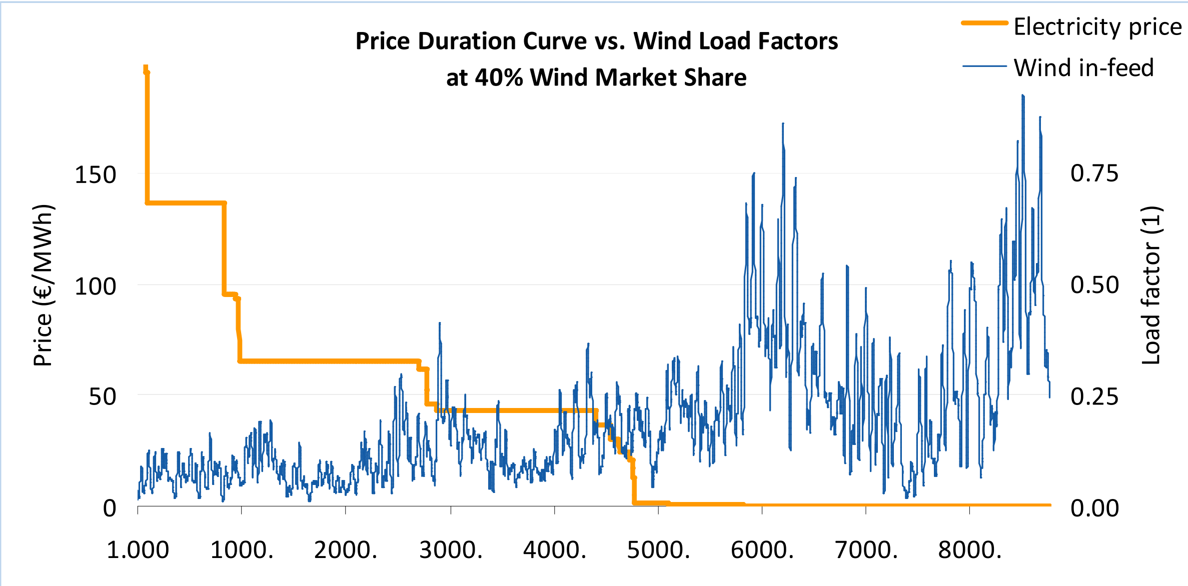


Figure A3c: Screening curves: Specific full costs (€/KW) as a function of FLH for different technologies.







Figures A4a-A4b: Ordered electricity prices (price duration curve) and wind-infeed during the respective hours. The differences between figure A7a and A7b are triggered by the price effect of wind-infeed. Note that the price drops to zero during more than 2000 hours at 40% wind market share.

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