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Incorporating Electricity Prices in Wind Turbine Design: Introducing the AEV Metric

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Abstract. This paper addresses the challenge of incorporating electricity prices into wind turbine design methods and shows how price volatility drives wind turbines towards larger rotors and lower specific power. Since wind speed and electricity prices fluctuate, current efforts to estimate a wind turbine's revenue are based on time-series approaches. However, this paper presents a new way of accounting for price volatility based on wind distributions, which is computationally cheap and easily integrates with current wind turbine and farm design methods and tools. The new method demonstrates that a traditional wind turbine can lose more than 15% of its revenue in open energy markets like Denmark due to price volatility. Designing turbines with lower specific power can substantially increase revenue by producing more energy at low wind speeds with higher energy demand and electricity prices.

1. Introduction

As we introduce more wind energy to open-market grids, the electricity prices tend to decline by the "merit-order effect" and correlate negatively with production [1, 2]. Therefore, while a wind farm owner will have high electricity production on windy days, the production revenue can be practically zero. Loth *et al.* [3] projects that the revenue for open-market grids with high wind energy penetration can be halved due to this price volatility.

Traditional wind turbines (WTs) reach their rated power at around 12 m/s and cut out at 25 m/s, i.e. they produce the most energy during high wind speeds. This leads to an imbalance between power production and consumption in regions with considerable wind and solar energy and can result in low or even negative electricity prices in periods with high wind speeds. On this background, the LowWind turbine concept [4] was proposed with the objective of making a major contribution to the system integration on the production side, where traditionally, the integration has only been on the consumption side, like battery storage and adaptive consumption. Low-wind WTs [4] have larger rotors and lower Specific Power (SP), making them more expensive. However, they produce more power during low-wind periods when electricity is expensive.

Swisher *et al.* [5] investigate the price point at which the LowWind WT concept, with an SP of only 100 W/m^2, becomes competitive in the energy system of Northern and Central Europe. They simulate the energy system (electricity, heat, and transport) until 2050 using the dynamic Balmorel model [6], giving it the objective of minimising the total system cost. Results show that the SP100 WT becomes disruptive if the cost is not more than 39% higher than a conventional WT. While the SP100 WT will find a lot of investments in low-wind regions, high-wind regions with transmission constraints, like Denmark, also see considerable investments.

Current WTs and WFs (wind farms) are designed to maximise the Annual Energy Production (AEP), a simple design metric to calculate and use. On the other hand, optimising for revenue requires dynamic information on the hourly energy price and production of the future electricity market, making it an impractical metric for WT and WF design. This paper defines a new design metric called the Annual Energy Value (AEV) that accounts for the negative production-price correlation. AEV is based on wind distributions instead of time-series and is therefore computationally cheap, can be implemented in current design methods, and can be used as a new "objective function" when optimising WTs and WFs. AEV can, therefore, be used to design a new generation of LWTs that better integrate with market demands.

1.1. Research questions

This paper investigates how we can design WTs that better align with the fluctuating energy demand. We first derive a mathematical model of calculating the WT revenue based on wind distributions instead of time-series. The mathematical model leads to the new AEV metric that can be seen as a price volatility correction to the well-known AEP metric. Next, we present an example of the new price curve for a site in Denmark. Finally, a parametric study is conducted of how the SP of a WT impacts the revenue when the electricity price is fixed and fluctuating. The paper tries to answer the following central questions:

(i) Can we calculate the annual revenue of a WT statistically instead of using time-series?
(ii) Does price volatility change the boundary conditions for WT design?
(iii) How does changing the SP of a WT affect its revenue?

2. A New Design Paradigm

Current objective functions for WT and WF design aim to minimise the cost of the energy produced. However, this design philosophy assumes that the value of energy is constant. In open energy markets with high shares of wind energy, wind power does not perfectly align with market demands and the energy price is reduced. Production needs to better align with the fluctuating energy demand to get higher prices and make future wind energy systems profitable. We, therefore, want a new objective function that includes the volatility of the electricity prices. This section derives such a metric that we call the Annual Energy Value (AEV).

2.1. A stationary revenue model

The revenue of a WT depends on the price of electricity and power production, which depends on wind speed. Since spot prices change each hour and there are distinct yearly weather patterns, we use these time scales to calculate the Annual Energy Revenue (AER). We can calculate AER using time-series [3] or with a statistical approach [7]:

$$\begin{aligned} AER &= 8766\,\mathbf{E}(r) \\ &= \sum_{i=1}^{8766} v_i\,p(u_i) \\ &= 8766 \int_0^{\infty}\int_{-\infty}^{\infty} v\,p(u)\,f(v,u)\,dv\,du \end{aligned} \tag{1}$$

$\mathbf{E}$ denotes the expected value, r is the mean hourly revenue, u_i and v_i are the mean wind speed and spot price values at a particular hour, $p(u) = \mathbf{E}(p|u)$ is the power curve, and the 8766 factor is the number of hours per year. Since the joint probability density function, $f(v, u)$, is hard to model, the current efforts use time-series of electricity prices and wind speed (Figure 1 left)

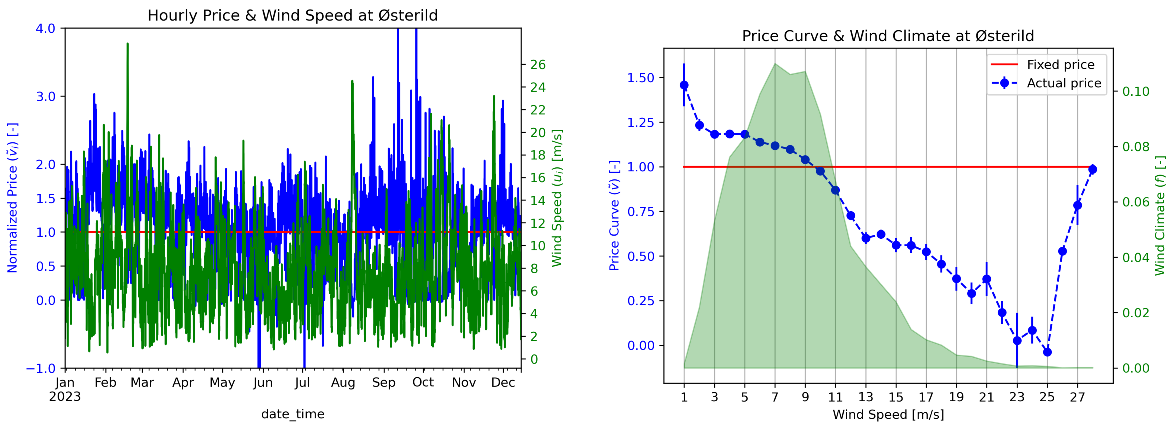

Figure 1: The same data from Østerild for 2023 is presented as time-series and statistically. Left: The hourly electricity price (blue) and wind speed (green). Right: The price curve (blue) and the wind climate (green). The annual mean price is shown in red.

to calculate the revenue. However, even though it is possible to dynamically simulate the spot price and wind speed at a wind farm location, these models are computationally expensive and have coarse spatial resolution.

To predict the revenue of each individual WT for layout optimisation or WT design, we want a stationary modelling approach that can quickly update the revenue estimation for each design iteration. We can do this by introducing the spot price's dependency on the wind speed:

$$
\begin{aligned}
\mathbf{E}(r) &= \int_0^\infty \int_{-\infty}^\infty v\, p(u)\, f(v,u)\, dv\, du \\
&= \int_0^\infty \int_{-\infty}^\infty v\, p(u)\, f(v|u)\, f(u)\, dv\, du \\
&= \int_0^\infty \left(\int_{-\infty}^\infty v\, f(v|u)\, dv \right) p(u)\, f(u)\, du \\
&= \int_0^\infty \mathbf{E}(v|u)\, p(u)\, f(u)\, du \\
&= \int_0^\infty v(u)\, p(u)\, f(u)\, du
\end{aligned}
\tag{2}
$$

$f(u)$ is the marginal probability density function of wind speed, often referred to as the wind climate, and $v(u) = \mathbf{E}(v|u)$ is a "price curve" that expresses how the mean spot price depends on the site-specific wind speed. For a given wind climate and price curve, we can revenue-optimise the WT as the wind climate and price curve are independent of the WT power curve. The price curve and wind climate can be described with only a few parameters instead of 8766 time-steps (Figure 1 right). Suppose we know the wind climate and price curve at one position in the wind farm (e.g. from measurements during the wind farm prospecting), then we can quickly extrapolate them to all WT positions using well-known stationary methods like the Wind Atlas methodology [7].

2.2. The Annual Energy Value

The IEC 61400-12-1 standard [8] evaluates the performance of wind turbines using the Annual Energy production (AEP). Therefore, most WF assessments and WT design tools calculate the AEP without considering the hourly price volatility. To make it straightforward to include price volatility, we define a new metric called the Annual Energy Value (AEV) that can directly replace AEP. AEV has the same units (Wh) as AEP but includes the energy devaluation when production and market demand misalign. Like Loth *et al.* [3], we use the average annual price ($\overline{v}$) to define the hourly normalised price ($\tilde{v} = v/\overline{v}$). If we combine this with Equation (2), we can write the AER as a function of the non-dimensional price:

$$\begin{aligned} AER &= 8766 \int_0^\infty v(u)\, p(u)\, f(u)\, du \\ &= \overline{v} \left(8766 \int_0^\infty \tilde{v}(u)\, p(u)\, f(u)\, du \right) \\ &= \overline{v}\, AEV = \overline{v}\, (\phi_V\, AEP) \end{aligned} \tag{3}$$

where $\phi_V = AEV/AEP$ is a price volatility correction factor that is the ratio of actual revenue to expected revenue when discounting price volatility. For markets with fixed electricity prices, AEV equals AEP and $\phi_V = 1$. As demonstrated in the Results section, the volatility loss can be more than 15% in markets with fluctuating prices, so it is important to consider this during WF development and WT design.

3. Method

Traditional AEP-optimisation of WT designs requires models of the power curve, $p(u)$, and the wind climate, $f(u)$. We need to add the price curve model, $\tilde{v}(u)$, to demonstrate how the inclusion of price volatility affects WT design. The models used in this paper are shown in Figure 2 and further described in the following section.

3.1. Wind climate $f(u)$ and price curve $\tilde{v}(u)$

Figure 1 left shows the time-series of the hourly wind speed and the normalised electricity for 2023. The wind speed is taken at a height of 106 meters from a met mast at Test Centre Østerild, located on the west coast of Northern Jutland, and the spot price is taken from the same price area (west Denmark). Figure 2 uses the same data set but presents the wind speed as a probability density function (left) and the spot price as a price curve (middle); the error bars represent the standard error of the mean.

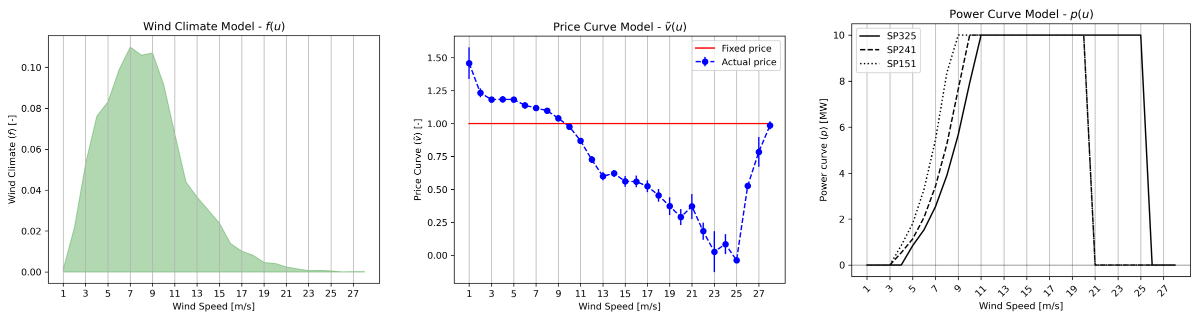

Figure 2: The three model types needed to calculate the Annual Energy Revenue (AER). Left: $f(u)$ - The wind climate (PDF). Middle: $\tilde{v}(u)$ - The price curves for Østerild/Denmark (”Actual price”) and a fixed price market (”Fixed price”). Right: $p(u)$ - The WT power curve models. SP indicates the specific power (the ratio of the rated power to the swept area).

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As seen in the middle of Figure 2 (”Actual price”), there is a clear trend of decreasing electricity prices at increasing wind speeds. The supply of wind-produced electricity is low at low wind speeds, and electricity prices increase. In contrast, the energy supply increases at higher speeds and prices decrease. At wind speeds above 24 m/s, many wind farms reach their cut-out wind speed, reflected in increasing electricity prices.

Traditionally, the wind climate is represented in compact form by the Weibull distribution:

$$f(u) = \frac{k}{A}\left(\frac{u}{A}\right)^{k-1} \exp\left(-\left(\frac{u}{A}\right)^{k}\right)$$

where A and k are the all-sector Weibull scale and shape parameters. Similarly, the price curve can be represented as a simple linear function of u:

$$\tilde{v}(u) = \alpha u + \beta$$

where α and β are also site-specific constants. In this work, however, we do not use the compact forms but apply the wind speed binned values (Figure 2) directly. As Denmark has a high share of wind energy, the price curve (”Actual price”) represents a market with high price volatility. To study how price volatility influences wind turbine design across markets, we will also consider a market with fixed pricing, $\tilde{v}(u) = 1$ (”Fixed price” on Figure 2). Comparing these two price curves can indicate how wind turbine design will develop for markets approaching Denmark’s wind energy penetration. The wind climate is fixed for all result comparisons presented in the paper.

3.2. Power curve models $p(u)$

We want to evaluate the effects of changing the WT’s specific power (SP)– the ratio of the rated power to the swept area. The WT is modelled using a simple parametric power curve. The power in the full load region is equal to the rated power (10 MW), while we use the power equation in the partial load region, assuming the optimal Power Coefficient (C_p=0.49):

$$p(u) = \frac{1}{2}\rho u^3 C_p \pi (D/2)^2$$

D is the rotor diameter, and the air density is $\rho = 1.225\,\mathrm{kg/m^3}$. We ignore wake effects since this work only analyses a single WT. The IEA 10-MW off-shore WT [9] is used as reference WT. It has cut-in and cut-out wind speeds of $u_{in} = 4\,\mathrm{m/s}$ and $u_{out} = 25\,\mathrm{m/s}$ and a rotor diameter of $D = 198\,\mathrm{m}$, giving it a $SP = 325\,\mathrm{W/m^2}$ (SP325). In addition to the reference SP325 WT, we define two LWT with rotor diameters of $D = 230\,\mathrm{m}$ (SP241) and $D = 290\,\mathrm{m}$ (SP151), with cut-in and cut-out wind speed of $u_{in} = 3\,\mathrm{m/s}$ and $u_{out} = 20\,\mathrm{m/s}$ (see Figure 2 right).

4. Results

4.1. The energy value density

Evaluating the revenue and production generation potential at varying wind speed ranges is important for designing WTs, as we can shift the production to lower or higher wind speeds by lowering or increasing the WTs’ SP. We can assess the average value of diverse wind speeds by defining the average energy value density $\left(\mathrm{Wm^{-2}}\right)$ as follows:

$$E_V(u) = \frac{1}{2}\,\rho\, u^3\, \tilde{v}(u)\, f(u)$$

where $f(u)$ is the wind climate, and $\tilde{v}(u)$ is the price curve at the specific location. A graph of this function shows which wind speeds are essential for energy revenue generation. Figure 3 left shows the energy density value for Østerild with and without the inclusion of price volatility.

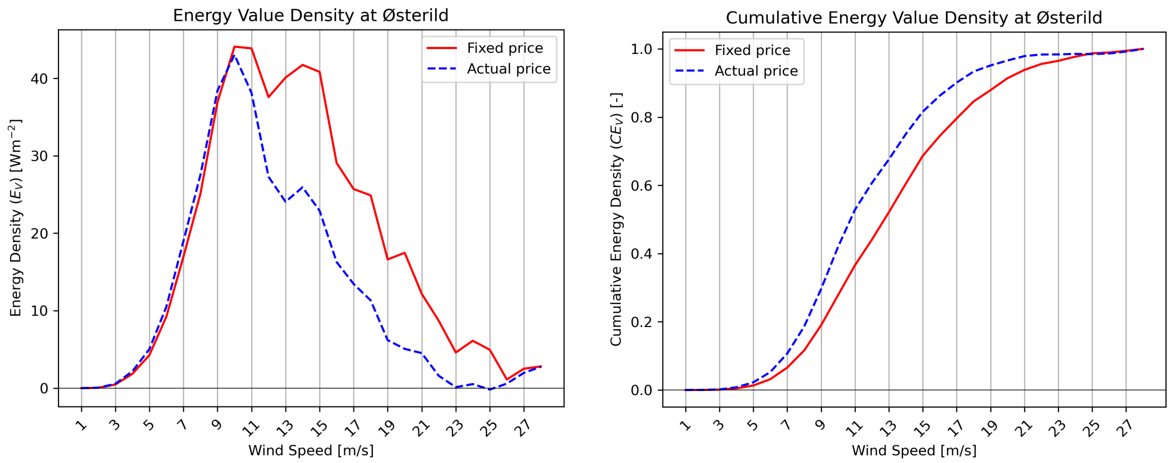

Figure 3: This figure shows the energy value density in order to evaluate the revenue generation potential at varying wind speeds. Left: Comparison of the energy density value with and without price volatility. Right: Comparison of the cumulative energy density value with and without price volatility.

When price volatility is included ("Actual price"), the energy value at higher wind speeds is reduced and even negative. The revenue of the produced electricity is markedly reduced at wind speeds higher than 10 m/s. Therefore, the effect of price volatility on the AER is similar to reducing the mean wind speed of the wind climate. LWTs may, therefore, be preferred in volatile markets despite good wind conditions.

4.2. The cumulative energy value density
To further illustrate how the main part of the AER is shifted to lower wind speeds in markets with price volatility, we define the cumulative energy value density:

$$CE_V(u) = \frac{\int_0^u E_V(u)}{\int_0^\infty E_v(u)}$$

The cumulative energy value density of Østerild is shown in Figure 3 right. The figure shows that 90% of the potential revenue is generated at wind speeds of 17 m/s and below ("Actual price"), despite only 80% of the energy can potentially be produced in this wind speed range ("Fixed price"). 20 m/s is a point of diminishing returns; almost no revenue can be created at higher wind speeds. Only 3% of the potential AER comes from the 20-25 m/s wind speed range, while 9% of the potential AEP can be found here. These numbers illustrate why WTs that operate in volatile markets should be designed for lower SP than traditional WT.

4.3. Price volatility loss
Now, we will look at how the SP325 reference WT performs in the fixed pricing market compared to the volatile one (Figure 2 middle). It is worth remembering that the power curve, wind climate, and mean electricity price are identical in this example; only the price volatility is changed.

Table 1 shows the AEP and AEV for the reference WT (SP325) in the two electricity markets. It is seen that the revenue in the market with price volatility is only 84.5% (AEV/AEP) of a market with fixed prices. In other words, there is no demand for 15.5% of the electricity produced, which might as well be curtailed. WF developers that aim to maximise AEP (or

Table 1: The AEP and AEV for the SP325 WT in a volatile and fixed-price market

	Fixed price	Volatile price
AEP [GWh]	41.6	41.6
AEV [GWh]	41.6	35.2
AEV/AEP [%]	100	84.6

Table 2: The AEP and AEV for the SP325, SP241, and SP151 WT in a volatile price market.

	SP325	SP241	SP151
Diameter [m]	198	230	290
AEP [GWh]	41.6	47.7	56.5
AEV [GWh]	35.2	42.2	51.9
AEV/AEP [%]	84.6	88.5	91.9

minimise the LCOE) are unaware of this volatility loss; only by calculating AEV can we see this loss.

4.4. Marked-aligned wind turbines

In Table 2, we compare the performance of WT SP325, SP241, and SP151 in the volatile price market. The wind climate and price curve are kept fixed; only the power curve is changed. As expected, the revenue (AEV) increases with lower SP-values. WT SP241 and SP151 have 19.8% and 47.4% higher AEV than SP325, respectively. The LWTs not only produce more electricity (higher capacity factor), but a larger fraction of the electricity is in demand (AEV/AEP). Only 8.1% of the energy produced by SP151 is not in demand and therefore curtailed.

Swisher *et al.* [5] showed that the LowWind SP100 WT would be disruptive in many European high-wind speed regions towards 2050 if the WT cost is not more than 39% higher than a conventional WT. The results presented here show that an SP151 WT is already competitive in Denmark if its cost is not more than 47.4% higher than a conventional WT.

5. Conclusions

This work explored the concept of incorporating electricity prices into wind turbine design. A new design metric, Annual Energy Value, was proposed to address the issue of price volatility and energy supply/demand mismatch in open energy markets. The paper also delved into the potential changes in wind turbine design under fluctuating electricity prices and examined how the specific power of a wind turbine influences its revenue. Based on these investigations, we can draw the following conclusions:

(i) The proposed AEV metric provides a feasible method for calculating the annual revenue of a wind turbine in dynamic pricing scenarios. It successfully accounts for price volatility using a new "price curve" that integrates with the traditional AEP calculation. The price curve is the only new "ingredient" compared to AEP calculations, and it can be determined by simply logging the electricity price during the wind measurement campaign. Keeping to the traditional wind distribution approach rather than time series offers a computationally efficient method of optimising wind turbines and farms that integrates with existing design methods and tools. As such, the AEV can be a one-to-one replacement for the IEC standard AEP performance metric.

(ii) Electricity price volatility significantly alters the boundary conditions for wind turbine design. In markets with high price volatility, there is a clear shift towards valuing energy produced at lower wind speeds more highly. This underscores the importance of re-evaluating traditional wind turbine designs, prioritising high-wind speed energy production. Especially in open markets like Denmark, which has high wind energy penetration, it is important to reconsider the design objectives; in the example presented, the traditional wind turbine (SP325) lost 15.5% of its revenue due to price volatility.

(iii) Changing a wind turbine's specific power significantly impacts its revenue in price-volatile markets. Lower specific power generates higher revenues in these markets, implying that larger rotor designs are more profitable despite increased costs. The increased revenue is caused by more low-wind speed energy production that better aligns with the fluctuating energy demand, leading to higher electricity prices.

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