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Article

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Mandatory direct marketing of wind power increases financing costs

By Thilo Grau, Karsten Neuhoff and Matthew Tisdale

The 2014 reform of the Renewable Energy Sources Act (*Erneuerbare-Energien-Gesetz*, or EEG) entailed that a mandatory direct marketing of green electricity be introduced. According to this law, operators of larger wind turbines must sell their electricity production on the electricity market. In addition to the wholesale price they receive a floating market premium, which is based on the average market value of all wind power in Germany. The mandatory direct marketing affects both the costs incurred, as well as the revenues earned, by the plant operator. The costs of compensating for forecast deviations in particular, as well as the changes in revenue due to differences in site-specific production profiles, create new risks for investors, and can increase financing costs of project-financed wind turbines. The dimensions of these effects were examined in various scenarios. Depending on the underlying assumptions, mandatory direct marketing may create additional support costs ranging from 3 to 12 percent for new wind turbines. Ensuring favorable financing costs should therefore be an important criterion in the further development of the EEG.

To promote renewable energy as a source of electricity, Germany introduced the Renewable Energy Sources Act (EEG) in the year 2000. This resulted in an increase in the share of renewables in gross electricity consumption from about 6 percent in 2000 to nearly 28 percent in 2014.¹ The EEG, which has since undergone several reforms, initially guaranteed technology-specific fixed tariffs for the grid feed-in of electricity from renewable resources. With the 2012 EEG amendment, a choice between a fixed feed-in tariff and a so-called floating market premium was introduced to incentivize the voluntary direct marketing of electricity from renewable energy sources. In this case, the EEG plant operators can either sell their electricity on the market themselves, or commission a direct marketer for this purpose. In addition to the sales revenue obtained for each kilowatt-hour of electricity sold, plant operators receive a premium that arises from the difference between the feed-in tariff determined by the EEG and the average market value of the power generated by the respective technology. The direct marketing option was particularly attractive due to an additionally granted management premium in accordance with the 2012 EEG, and because of the possibility of reinstating the established feed-in tariff for the operators of existing wind turbines at any time. In December 2014, the power generated by onshore wind turbines with an installed capacity of nearly 32 gigawatts was marketed directly via the market premium.²

The current 2014 EEG eliminates this choice for large new plants, and gradually introduces the mandatory direct marketing with a floating market premium in order to better integrate renewable energy into the existing electricity market. Since August 1, 2014, the direct marketing has been mandatory for electricity from new

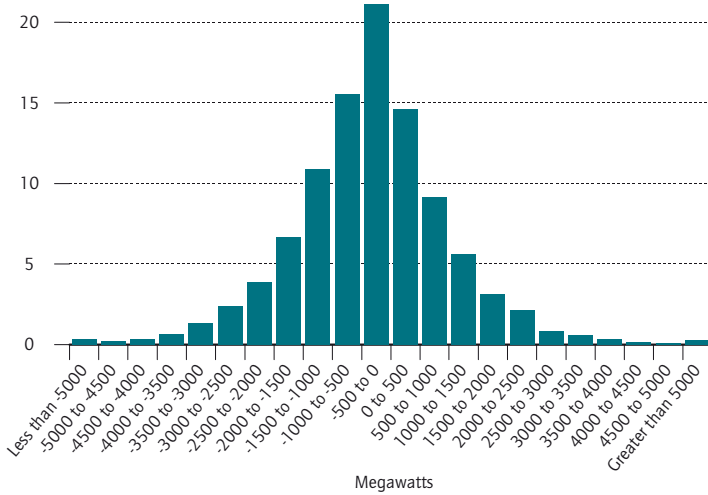
¹ Federal Ministry for Economic Affairs and Energy (2015): *Zeitreihen zur Entwicklung der erneuerbaren Energien in Deutschland* (Time series for the development of renewable energies in Germany), as of February 2015.

² 50Hertz, TransnetBW, TenneT, Amprion (2014): *Informationen zur Direktvermarktung nach § 33b EEG 2012 bzw. § 20 Abs. 1 EEG 2014* (Information on direct marketing).

Figure 1

Distribution of hourly deviations between actual wind energy feed-in and day-ahead forecast for the control area of Tennet 2012

Frequency of specific size categories in percent



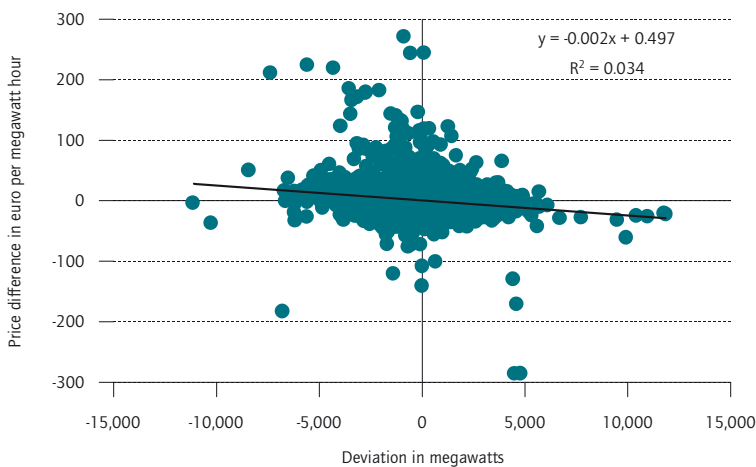
Sources: Tennet; calculations of DIW Berlin.

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Forecasts tend to overestimate wind energy feed-in.

Figure 2

Hourly deviations between actual wind energy feed-in and day-ahead forecast as well as between intraday and day-ahead prices 2012



Exemplary illustration for the control area of Tennet.

Sources: Tennet; EPEX Spot; calculations of DIW Berlin.

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In case of overestimated forecasts intraday prices tend to be higher.

plants whose capacity exceeds 500 kilowatts (kW).³ From 2016 onward, mandatory direct marketing will also apply to new plants whose capacity exceeds 100 kW.

The 2014 changes to the EEG affect both the revenues earned as well as the costs incurred by plants that exploit renewable energies. Investors must now factor in the costs resulting from forecast deviations. In addition, depending on the production profile of a particular site, there may be deviations from the average achievable market value. Moreover, there is uncertainty about the development of these revenues and/or these costs. DIW Berlin calculated possible dimensions of the costs of forecast deviations and of the site-specific differences with regard to the revenue possibilities. Moreover, an analysis was carried out with regard to how these new costs as well as the uncertainties over their future development could impact the capital structure and financing costs in the financing of onshore wind energy projects.⁴

Forecast deviations increase costs for plant operators

The actual amount of electricity generated by wind power and photovoltaic systems regularly differs from the forecasts made the day before. Plant operators — or the direct marketers they have commissioned — initially sell electricity at the day-ahead market according to the projected electricity production. In the case of forecast deviations, operators must align their positions with the actual generation of wind power through trade in the intraday market (Figure 1).

Depending on under- or overproduction, additional costs or revenues may arise here. The costs of the forecast deviations can be calculated as a product of the deviations between the actual and forecasted wind energy feed-in and the difference between intraday and day-ahead electricity prices (Box). When the actual wind energy feed-in exceeds the forecasts, the intraday prices are usually lower than the day-ahead prices, and vice versa (Figure 2).

Using the historical market prices and wind data, it is possible to calculate the average annual costs of the forecast deviations (Table 1). The average costs of the deviations in terms of the marketing revenues from the day-ahead and intraday markets amount to about three percent. In individual months and control areas, however, this value can be significantly higher.

³ German Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz – EEG 2014).

⁴ For details on the calculations, see: Tisdale, M., Grau, T., Neuhoff, K. (2014): Impact of Renewable Energy Act Reform on Wind Project Finance. DIW Berlin Discussion Paper 1387.

Box

Calculation Methodology

The hourly costs of the forecast deviations can be calculated as a product of the deviations between actual wind power production (extrapolated) and forecasts from the day before, and the difference between intraday and day-ahead electricity prices. The calculations are based on wind power data published by the transmission system operators (TSOs)—the forecasted and actual wind power feed-in of the control areas of Tennet and 50Hertz—as well as price data from EPEX SPOT where the "last price" of every hour for intraday trading was used. This conforms to the assumption that deviations are being marketed at the latest possible moment. The assumption that 100 percent of the previous day's forecast is sold on the day-ahead market also applies here. After the close of the intraday market, the remaining forecast deviations must be offset through the usage of balancing energy, where

necessary. The resultant energy balancing costs are not considered in this analysis.

To calculate the site-specific revenue opportunities, the wind power feed-in was calculated for three exemplary locations in North, Central, and Southern Germany using the average hourly wind speeds supplied by the German Weather Service.

The cash-flow model calculates the debt share as well as the return on equity for the project financing of wind turbines. The model assumes specific investment costs of € 1 400/kW, an average wind turbine capacity factor of 19 percent, a debt service coverage ratio of 1.1, a 20-year repayment term and plant life cycle, and borrowing costs of 3.5 percent.

Table 1

Costs of forecast deviations in relation to revenues
In percent

	Tennet	50Hertz
2010	3.5	4.3
2011	2.7	2.9
2012	1.5	3.8

Source: Calculations of DIW Berlin.

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Costs of forecast deviations amounted to around three percent on average.

Site-specific factors can also affect revenues

The revenues of wind turbine operators are made up of the marketing revenues as well as the revenues from the floating market premium. The market premium arises from the difference between the EEG's fixed plant-specific tariff and the average market price of the electricity production of all onshore wind turbines from the previous month. If the site-specific hourly electricity production of a wind turbine differs from the average wind power supply in Germany, the proceeds from this turbine also deviate from the EEG tariff. In principle, this could generate both gains and losses, but either way, the uncertainty with regard to revenue opportunities increases from an investment perspective.

The calculations make it clear that the revenue opportunities may vary significantly in different locations in

Germany. The examination of exemplary sites reveals that the revenues can be significantly below the average in individual cases.⁵

Direct marketing lowers debt shares and increases financing costs

To analyze the impact of the costs of forecast deviations and site-specific revenue fluctuations, as well as the resultant uncertainties on the capital structures and financing costs of wind power projects, the calculated values were used as input parameters of a cash-flow model for various scenario analyses. Assuming that wind turbines are project financed, the cash-flow model developed here calculates the equity and debt shares as well as the return on equity (Box).⁶ The following scenarios were defined:

- "Risk-free": No new costs or risks. This essentially corresponds to a continuation of the EEG without mandatory direct marketing, which entails that the costs of forecast deviations are not borne by the wind turbine operators.
- "Risk-neutral": The costs of forecast deviations amounting to three percent are borne by the wind turbine operators. This corresponds to the average calculated historical value. It is also assumed that there are no site-specific reductions in revenue.

⁵ For the full calculation method in detail, see: Tisdale, M., Grau, T., Neuhoff, K. (2014), I.c.

⁶ For details on the structure of the model and the choice of parameters, see: Tisdale, M., Grau, T., Neuhoff, K. (2014), I.c.

Table 2

Debt share and return on equity in scenarios with constant EEG tariff

In percent

Scenario	Debt share	Return on equity
Risk-free	85.2	10.8
Risk-neutral	83.2	7.7
Risk-averse	76.1	-0.1
Asymmetrical	76.1	6.2

Source: Calculations of DIW Berlin.

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The return on equity differs substantially between scenarios.

- “Risk-averse”: From an investor’s perspective, a more pessimistic value of the forecast deviation costs amounting to eight percent is assumed. In addition, site-specific revenues that are seven percent lower are assumed. Debt investors therefore adopt a conservative perspective in this scenario, using more unfavorable values as a basis.
- “Asymmetrical”: Combination of risk-neutral equity investment and conservative lending. The equity investor assumes the values of the “risk-neutral” scenario in terms of the revenue, while the values of the “risk-averse” scenario apply for credit lending. In this way, the “asymmetrical” scenario simulates the perspective of an equity investor who is willing to bear more risks than a lender is.

Assuming a fixed compensation of € 89/MWh, the simulation results show how the debt share and the return on equity are decreasing with rising costs and/or risks. The debt share drops compared to the baseline scenario by around two to eleven percent, and the return on equity drops by 29 percent to 101 percent (Table 2).

While yields of about five percent are acceptable for civil energy cooperatives, commercial and institutional investors are expecting higher returns on equity in the amount of roughly eight percent when investing in large wind turbines.⁷

⁷ Values based on interviews with various investors. Nine percent return on equity for wind onshore according to Kost, C., et al. (2013): Levelized Cost of Electricity Renewable Energy Technologies. November 2013, Fraunhofer ISE, Freiburg.

Table 3

Required changes of the EEG tariff to reach a return on equity of 8 percent

	EEG tariff in Euro per megawatt hour	New debt share in percent
Risk-free	87.78	83.7
Risk-neutral	89.16	83.4
Risk-averse	94.38	82.9
Asymmetrical	90.50	78.0

Source: Calculations of DIW Berlin.

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In the “risk-averse” scenario, the highest tariff is needed.

Possible increase in support costs due to changes in risk allocation

Scenario analyses allow for a direct quantification of the additional support costs that would result from the investors bearing the costs of the forecast deviations and site-specific revenue risks. It is assumed that the same trajectory in terms of the installed wind power capacity is desired.

For this purpose, the EEG compensation in each respective scenario is set in a way such that a hurdle rate of eight percent is reached—that is, a reasonable return is achieved for commercial and institutional equity investors (Table 3). The debt share differs for each respective scenario due to straight-line depreciation and rising variable operating and maintenance costs.

If the costs of forecast deviation—according to our calculations averaging at three percent of the revenue—are transferred from the network operator to the plant operator, and if these costs could be solidly predicted for the duration of the plant’s life cycle, then no additional risks would arise. The increase of the EEG compensation (and therefore the corresponding EEG apportionment) in the “risk-neutral” scenario compared to the “risk-free” scenario is compensated by a reduction in the costs borne by the network operator, and thus a reduction of the network charges.⁸

However, if the plant operators must bear the fluctuating costs of forecast deviations, then a risk is transferred to them. If the site-specific revenue risk is also transferred, then the EEG compensation would have to

⁸ Prior to the introduction of direct marketing, the costs of the forecast deviations were initially incurred by the network operators, and were then passed on to the end consumers via the network charges.

be increased to €94.38/MWh in the “risk-averse” scenario—that is, by more than €5/MWh compared to the “risk-neutral” scenario. Assuming a longer-term wholesale wind power market value of €45/MWh, and therefore a funding component of around €49/MWh, the support costs would increase by 12 percent in relation to the “risk-neutral” scenario.

If the equity investor is considered risk-neutral, and only the lenders make conservative assumptions on revenue development (“asymmetrical”), then the EEG compensation would have to rise by only around €1/MWh and the support costs by 3 percent compared to the “risk-neutral” scenario. If investors assume that the introduction of mandatory direct marketing with a floating market premium comprises only these two risk components, a three to almost twelve percent increase in support needs would be expected for new plants, depending on the particular scenario assumptions.

However, other risk factors are not factored into our calculations. For instance, with the additional complexity of the floating market premium compared to a fixed feed-in tariff, the probability of subsequent adjustments increases—for example, those resulting from developments in the electricity market design, which may also adversely affect the revenues.

Likewise, possible efficiency gains in plant operation, which should be incentivized through the incentives for better wind forecasts, are not taken into account in our calculations. From a longer-term perspective, direct marketing could help ensure that sites and plant designs conform to market requirements. From a present perspective, however, it is unclear how high these efficiency gains could be, and whether the above-described transfer of risks to plant operators is necessary for their development, or whether other combinations of market design and incentives are possible. For instance, it can be assumed that with the introduction of intraday auctions, such as the quarter-hour auctions carried out by EPEX SPOT, regulated and unregulated market participants in the intraday market can achieve the same revenues and conduct system-oriented trades.

Current deployment success cannot be traced back to mandatory market premium

Despite the additional investment risk, the installed electricity capacity of onshore wind turbines in Germany has increased to 38.1 GW in 2014, which is 4.4 GW more than in the previous year.⁹ The total investment costs of onshore wind energy in Germany were relative-

ly stable between 2006 and 2012, and are unlikely to have changed significantly in 2014, either.¹⁰ While the 2014 EEG’s basic compensation (basic tariff) for onshore wind energy increased by 1.6 percent compared to the 2012 EEG, the initial tariff (for the first years after the commissioning of the plant) was reduced by 0.3 percent. The management premium for onshore wind energy amounted to 1.2 ct/kWh in 2012. With the 2014 EEG, the management premium amount is included in the tariff. In comparison to installations that received a market premium within the framework of EEG 2012, the tariff within EEG 2014 therefore was reduced by 16 percent (in the case of five years with high initial tariff) and 12 percent (in the case of 20 years with high initial tariff), respectively.

The most important factors left to explain the recent deployment success are therefore the favorable financing framework conditions offered by KfW and commercial banks (historically low interest rates averaging 2.2 percent at the end of 2014, compared with 3.6 percent in early 2012),¹¹ and the so-called pull-forward effects due to project developments that were accelerated in order to avoid uncertainties with regard to the announced transition to a tendering system.

Conclusion

For new wind turbines, the 2014 EEG reform carries the risk of additional costs and lower revenues, which can increase the financing costs. In particular, two changes that arise from the now-mandatory direct marketing have a major impact. On one hand, the fact that operators must bear the costs of forecast deviations leads to increasing and unstable operating costs. On the other hand, due to site-specific wind power profiles that could differ from the average wind power output profile in Germany, the combination of electricity market price and market premium can fall below the former feed-in tariff. Calculations of these factors based on historical data show that the average costs of forecast deviations amount to about three percent of electricity market revenues, and that they can be significantly larger in particular months and control areas. Furthermore, the revenues may stand significantly below the average in exemplary locations.

Due to the additional risks involved, investment opportunities in wind farm projects can develop unfavorably. The

⁹ Federal Ministry for Economic Affairs and Energy (2015), l.c.

¹⁰ Deutsche WindGuard (2014): Kostensituation der Windenergie an Land, Internationaler Vergleich (Expense situation of onshore wind power, international comparison).

¹¹ Deutsche Bundesbank (2015): Time series BBK01.SUD119, effective interest rates of German banks/new business/housing loans to private households with an initial fixed interest rate over 10 years as a proxy for costs of long-term lending to customer groups with low risks.

results of the cash-flow simulation show that, depending on the hypothetical scenario, the debt share may drop by two to eleven percent while the return on equity may be greatly reduced. In the considered scenarios, this may result in increased support costs for new plants ranging from three to just under twelve percent, which must ultimately be borne by electricity consumers.

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The results show that small changes such as the 2014 EEG reform transition from an optional to a mandatory direct marketing with a floating market premium can have a significant impact on the project financing for new wind turbines. Ensuring favorable financing costs should therefore be an important criterion in the future development of the EEG.

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