EUI Working Papers

RSCAS 2012/19
ROBERT SCHUMAN CENTRE FOR ADVANCED STUDIES
Climate Policy Research Unit

CARBON PRICE AS RENEWABLE ENERGY SUPPORT? EMPIRICAL ANALYSIS ON WIND POWER IN DENMARK

Claire Gavard

EUROPEAN UNIVERSITY INSTITUTE, FLORENCE
ROBERT SCHUMAN CENTRE FOR ADVANCED STUDIES
CLIMATE POLICY RESEARCH UNIT

Carbon price as renewable energy support? Empirical analysis on wind power in Denmark

CLAIRE GAVARD

EUI Working Paper **RSCAS** 2012/19

ISSN 1028-3625

Printed in Italy, May 2012
European University Institute
Badia Fiesolana
I – 50014 San Domenico di Fiesole (FI)
Italy
www.eui.eu/RSCAS/Publications/
www.eui.eu
cadmus.eui.eu

Robert Schuman Centre for Advanced Studies

The Robert Schuman Centre for Advanced Studies (RSCAS), created in 1992 and directed by Stefano Bartolini since September 2006, aims to develop inter-disciplinary and comparative research and to promote work on the major issues facing the process of integration and European society.

The Centre is home to a large post-doctoral programme and hosts major research programmes and projects, and a range of working groups and *ad hoc* initiatives. The research agenda is organised around a set of core themes and is continuously evolving, reflecting the changing agenda of European integration and the expanding membership of the European Union.

Details of the research of the Centre can be found on:
http://www.eui.eu/RSCAS/Research/

Research publications take the form of Working Papers, Policy Papers, Distinguished Lectures and books. Most of these are also available on the RSCAS website:
http://www.eui.eu/RSCAS/Publications/

The EUI and the RSCAS are not responsible for the opinion expressed by the author(s).

Climate Policy Research Unit

The Climate Policy Research Unit (CPRU) is a research group within the Robert Schuman Centre for Advanced Studies under the Loyola de Palacio Chair. The goal of the CPRU is to provide a reliable source for information and analysis of EU climate policy and a forum for discussion of research carried out in this area among government officials, academics and industry.

The CPRU was established in 2010 at the initiative of Josep Borrell, President of the EUI and former President of the European Parliament, as a means of providing more focus to European climate policy developments. The director of the CPRU is Denny Ellerman, part-time professor at the RSCAS, and recently retired as a Senior Lecturer from MIT's Sloan School of Management. The CPRU works in collaboration with the energy and regulatory policy research groups of the Florence School of Regulation and Loyola de Palacio Chair and with the Global Governance Programme at the EUI. Starting in 2012, the CPRU has been funded primarily by the European Commission (DG Climate Action).

The opinions expressed in this paper are those of the author(s) and do not represent the views of the European University Institute or any of its subsidiary components or those of the European Commission.

For more information:

www.florence-school.eu/portal/page/portal/LDP_HOME/Research/Climate_Policy_Research_Unit

Abstract

Empirical analysis on wind energy in Denmark is used to quantify the impact of the various support policies in place in the last decade and infer the carbon price that would lead to the same level of deployment under the hypothesis of revenue certainty equivalence. Probit analysis on monthly data is used to test the impact of electricity price and support policies on the observation of new turbine connections to the grid. The support level is the dominant factor while the impact of the past electricity price is limited. A feed-in tariff regime significantly brings in more wind energy than a fixed premium. No difference between the impacts of a variable and a fixed premium is found. The probability of new connections as a function of the support level and the policy type is used to give an indication of the carbon price level that would support similar renewable deployment.

Keywords

Carbon price, Denmark, renewable support policies, wind power.

Introduction[*]

In Europe, the coexistence of a common carbon market and national renewable support policies raises the question whether a carbon price alone could replace renewable energy support policies. What level of carbon price would be needed to achieve deployment comparable to that from existing renewable energy support policies? M.I. Bianco and G. Rodrigues partly addressed this question by computing an equivalent carbon credit level of each national wind support policy in effect in Europe in 2006. They use assumptions on the amount of greenhouse gases avoided by wind energy but do not take account of the actual impact of each policy on wind turbine deployment (Bianco and Rodrigues, 2008). On the other hand, many studies compared the impact of various types of renewable support policies, without necessarily taking account of the stringency level of each of them (for example Menz and Vachon, 2006 on the United States experience).

The purpose of the work presented here is to conduct an empirical analysis of the conditions that lead to wind energy deployment and from these results, to infer the carbon price level that would attain significant deployment. The analysis focuses on Denmark given electricity price and support policy changes over time. Econometric techniques are used to test the effect of these parameters on on-shore wind power deployment on a monthly basis on the time period 2000-2010. A discrete choice econometric model is used to analyse the observation or absence of observation of new turbine connection to the grid. From the results of the econometric analysis, a carbon price level that would attain significant wind power deployment is inferred. This equivalent carbon price is computed from a model of difference in profitability between renewable and fossil fuel technologies.

In part 2, the choice of Denmark for the analysis is explained and the history of wind energy in this country is noted as the context of the analysis. At the aggregate level, the observation of wind capacity over time in parallel with support policy changes already gives some indications about the impact of the various types of support and about the support level needed to have wind power deployment.

The econometric analysis that is presented in part 3 aims at quantifying these impacts. The model used for the econometric analysis is introduced. It is based on the profit function for wind energy. The data base preparation is explained. Results of the probit analysis on the observation of connection of new turbines to the grid are presented. They indicate that the support level impact is dominant and that the influence of past electricity prices is limited and dominated by the support level. They also show that a feed-in tariff policy significantly brings in more wind than a premium policy but that a variable premium does not have a significantly different impact than a fixed premium. The probability of connection of new turbines to the grid as a function of the policy type and the support policy is computed and presented. It indicates that on average 22€/MWh is the support level needed, in addition to electricity price, to have a probability of 0.5 to observe connection of new turbines to the grid. The robustness of these results is then discussed.

In part 4, the equivalence between carbon price and renewable support policies to cover cost differences between renewable and conventional technologies is introduced. It is used to convert the results from the econometric analysis into a carbon price level, under revenue certainty equivalence.

[*] This work was largely done while the author was a research assistant in the Climate Policy Research Unit of the Loyola de Palacio Chair. C. Gavard is presently with the Centre d'Economie de la Sorbonne in Paris 1 University. The author gratefully acknowledges A. Denny Ellerman for his supervision and Joeffrey Drouard, Aleksander Zaklan, Udaya Bhaskar Gunturu, Jing Xu, and Djamel Kirat for useful comments and suggestions. All errors remain the author's own responsibility.

1. Wind energy in Denmark

Denmark is chosen for its long wind power history, the frequency of changes in the type and level of its wind support policies and the large amount of data available for wind energy.

On shore wind support policies began in Denmark in 1976 (Energistyrelsen, Jauréguy-Naudin, 2010). They are summarized in Table 1. Between 1976 and 2000, several policies juxtaposed each other and sometimes overlapped. From 1976 to 1989, the Danish state reimbursed part of the investment for building wind turbines. The support was originally 40% of the investment cost and was then reduced gradually until the scheme was cancelled in 1989. From 1984 to 2001, the electricity price paid to producers of wind power was 85% of the local retail price of electricity excluding taxes. In1991, a fixed price premium of 36€/MWh was introduced in addition to the previous scheme. It was in place until 2001. In 1999, the Danish electricity market was liberalized. Existing turbines were then covered by a special feed in tariff (FIT) which resulted in a comparable income for producers as under the previous support scheme. For existing wind turbines connected before the end of 1999, producers received a feed in tariff of 80€/MWh for a number of full load hours (25.000 full load hours for turbines below 200kW, 15.000 full load hours for turbines below 600kW, 10.000 full load hours for turbines larger than 600kW). After full load hours were used, producers received a feed-in tariff of 58€/MWh until the turbine was ten years old. They then received a price premium of maximum 13€/MWh until the turbine was 20 years old. The sum of market price and price premium was limited to 48€/MWh. An additional price premium of 3€/MWh was paid to cover balancing costs[1] in the electricity market.

Table 1 - On-shore wind support policies in Denmark

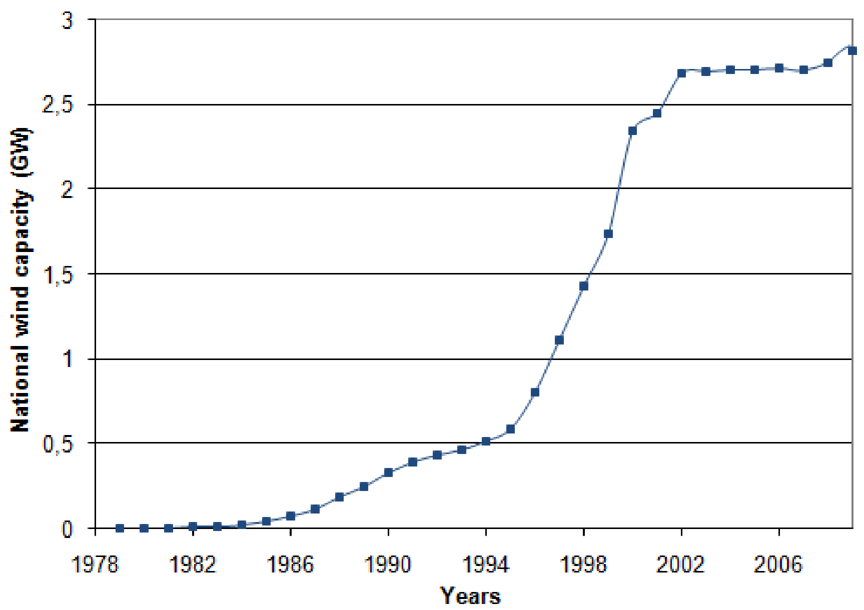
Date of connection to the grid	Support Scheme
From 1976 to 1989	Financial support from the Danish state
From 1984 to 2001	Electricity price paid to producers : 85% of the local retail price, excluding taxes
From 1991 to 2001	Fixed premium of 36 €/MWh in addition to the previous scheme
Existing turbines bought before end of 1999	Feed-in tariff of 80€/MWh for a number of full load hours
	Then feed-in tariff of 58€/MWh until the turbine is 10 years old
	Then premium of 13€/MWh or less until the turbine is 20 years old
2000 - 2002	Feed-in tariff of 58€/MWh for 22,000 full load hours
	Then premium of 13€/MWh or less until the turbine is 20 years old with a limit of 48€/MWh on the sum of market price and premium
	Additional premium of 3€/MWh
2003 - 2004	Premium of 13€/MWh or less until the turbine is 20 years old, with a limit of 48€/MWh on the sum of market price and premium
	Additional premium of 3€/MWh

[1] A producer, for example a wind turbine owner, has to forecast the production on day ahead and sell it to the power exchange. Any deviations from the forecasted wind production are covered by means of regulating power. The costs of offsetting the imbalances in wind power production are charged to turbine owners. The 3€/MWh allowance is paid to turbine owners to help them pay these balancing costs.

2005 - February 20th 2008	Fixed premium of 13€/MWh until the turbine is 20 years old
	Additional premium of 3€/MWh
After February 21st 2008	Premium of 34€/MWh for the first 25,000 full load hours
	Additional premium of 3€/MWh

From 2000, four policies were successively in place. For turbines connected to the grid between 2000 and 2002, producers received a fixed feed-in tariff of 58€/MWh for the first 22,000 full load hours. They then received the wholesale spot market electricity price (37€/MWh in 2008) in addition to a premium of 13€/MWh, until the turbine is 20 years old. The sum of market price and price premium was limited to a maximum of 48€/MWh.In 2002, the support scheme changed from a feed-in tariff to a variable premium to better integrate with the recently liberalized electricity market. For turbines connected to the grid in 2003-2004, the premium scheme was associated with a cap on the total remuneration per unit of electricity produced. For the first 20 years of the turbine lifetime, producers received the wholesale spot market electricity price in addition to a premium of 13€/MWh. The sum of the market price and the price premium was limited to 48€/MWh. In 2005, the cap on the total remuneration per unit of electricity produced was removed. For turbines connected to the grid between January 2005 and February 20th 2008, producers received the wholesale spot market electricity price in addition to a premium of 13€/MWh for the first 20 years of the turbine lifetime. In 2008, the current regime came into effect when the premium was increased. For turbines connected to the grid after February 21st 2008, producers receive the wholesale spot market electricity price in addition to a premium of 34€/MWh for the first 25,000 full load hours. Under all four regimes and for the entire lifetime of the turbine, an additional allowance of 3€/MWh has been paid to producers to cover balancing costs.

Figure 1 - On-shore wind capacity in Denmark since its early stage[2]



[2] Data source: Energistyrelsen.

The observation of aggregate on-shore wind capacity in Denmark (Figure 1) in parallel with the corresponding support policies shows a correspondence between the growth of capacity and the support scheme: most of the growth in wind capacity occurred either between 1995 and 2002, or after 2008, which means either under a premium of 36€/MWh, a feed-in tariff of 58€/MWh or under a premium of 34€/MWh. Given electricity prices in 2000-2002, the feed-in tariff of 58€/MWh can be seen as equivalent to a premium of more than 30€/MWh, under revenue certainty equivalence. This suggests a threshold effect, that is to say, the existence of a support level above which new turbines are connected to the grid and below which no new connections are made. The purpose of the analysis in this paper is to take advantage of this long and diverse history of wind power in Denmark to quantify the impact of wind support policies and to infer a carbon price that would attain comparable wind power deployment. Econometric analysis is used to do this empirical analysis and a discrete choice model is chosen as an appropriate approach to analyze the presence or absence of observations of new turbine connection to the grid and take account of a possible threshold effect. The analysis is done for on-shore wind power for the time period 2000-2010, during which support policies are clearly and distinctly defined.

2. Econometric Analysis of Wind Power Deployment

The econometric analysis that is done is based on the profit function for wind energy producers. After it is presented, the econometric model is introduced and data preparation is explained. Results are then presented and their robustness is discussed.

2.1 Profit Function for Wind Energy

The profit function π_i for energy technology i is defined as the profit on the life time of the plant divided by the amount of electricity produced during it:

$$\pi_i = P_e + X_i - C_i - E_i \text{ with } X_i \geqslant 0$$

where:

P_e is the expected electricity price revenue,

X_i is the revenue from the premium for electricity produced by technology i,

C_i is the levelized cost of electricity for technology i,

E_i is the emissions costs for technology i.

For a renewable technology r, there is no emission cost and the profit function is

$$\pi_r = P_r + X_r - C_r \text{ with } X_r \geqslant 0$$

For wind power, costs are mainly fixed costs so that C_r is upfront investment cost[3] divided by the quantity of electricity produced. A large part of the investment cost is the turbine price, which is function of the turbine capacity. The quantity of electricity produced is a function of the turbine capacity as well and the wind power density (W/m²) of the site where it is built. Hence C_r is a function of the investment cost in €/kW and the wind power density of the turbine site (C_r decreases in wind power density of the turbine site).

3 The turbine price is the major component of the investment cost. The quantity of electricity produced is a function of the turbine characteristics (particularly the turbine capacity) and the wind power density of the site where the turbine is installed. M. Bolinger and R. Wiser show that the levelized cost does not depend on the turbine size because higher energy production compensates for the increase in the turbine price. But the levelized cost does depend on the turbine pricing per kW and on the wind power densitywind power density of the site where the turbine is built (Bolinger and Wiser, 2011).

2.2 Econometric Model

The decision to build a new turbine depends on the profit that can be expected from it. The decision is made only if the profit is positive or equal to zero. Hence, given the profit function described above, this decision can depends on the expected electricity price and premium, turbine investment costs, and the wind characteristics of the turbine site.

Probit analysis is chosen to examine the impact of electricity prices, the support type (feed-in tariff, fixed premium or variable premium), support level and levelized cost on the decision to build a new turbine. This decision is a binary variable and is observed through the connection or the absence of connection of new turbines to the grid per month. As the impact of electricity price and support may vary with the type of support policy that is used, dummy variables are introduced to characterize the support policy type and to check if the type of support has an impact or not. Hence the econometric model used for the probit analysis is the following:

$$Prob\ (Y_t = 1|A_t) = F(\beta_1 + \beta_2\ elecprice_{t,-n} + \beta_3 support_{t,-n} + \beta_4\ FIT + \beta_5\ VP + \beta_6\ support_t * FIT + \beta_7\ cost_t)$$

Where:

Y_t is a binary variable corresponding to the presence or absence of connection of new turbines to the grid in the time period t.

A_t is the vector of all explanatory variables considered.

F is the cumulative distribution function of the standard normal distribution.

$elecprice_t$ is the electricity price averaged on the time period t. Lags are tested to test whether past electricity prices influence the investment decision of wind project developers.

$support_t$ is the level of the support policy under which the new turbine is built. If the policy type is a fixed premium, $support_t$is the premium itself. If the policy type is not a fixed premium, the support level is converted into a premium given electricity prices during the time period t.

FIT and VP are the dummy variables for feed-in tariff and variable premium policies. The fixed premium policy is taken as the reference category. The variable $support_t * FIT$ is the interaction term between $support_t$ and the dummy variable FIT.

$cost_t$ is the levelized cost of wind power[4]. Given the explanations presented in part 3.1, it can be seen as investment cost in €/kW divided by the wind power density of the site where the turbine is built. Wind power density is not observed when there is no new connection to the grid. Investment cost is then taken as a proxy for the cost term.

Lags up to five years are tested both for the electricity price and up to two years for the support level. The reason is that consideration of the site chosen for a turbine is done up to five years before the date of connection of the turbine to the grid and the first MWh produced. Then there is usually one year between the start of the building of the turbine and the date of connection to the grid. The start of the building of the turbine can be seen as the point of irreversibility in the decision process. Past electricity prices are presumed to be used as electricity price projections by wind project developers. Past electricity prices can also be seen as a form of insurance against a change in the support policy.

---

[4] M. Bolinger and R. Wiser show that turbine price vary with time but that it does not necessarily decrease. They present how endogenous and exogenous factors such as foreign exchange rate and labor cost explain its variability over time (Bolinger and Wiser 2011).

Given the data, the interaction term between the VP dummy variable and the $support_t$ variable was almost perfectly collinear with the VP dummy variable. Hence, it was not relevant for the analysis.

Given the profit function described previously, β_2 and β_3 are expected to be positive while β_7 is expected to be negative. Given previous comparisons between various types of wind support policy (for example Menz and Vachon, 2006) and the frequent conclusion that a feed-in tariff regime attains larger wind power deployment (Couture, Cory, Kreycik and Williams, 2010), β_4 is expected to be positive.

2.3 Data Preparation

A monthly data base on the time period 2000-2010 is built. The variables needed for the econometric analysis and introduced above are defined as follows.

Data on Danish wind turbines are found on energinet.dk, the Danish transmission system operator for electricity and natural gas. A large database on all turbines that have been in operation in Denmark allows identifying the date of connection of each Danish turbine to the grid so that they can be grouped into monthly observations. This defines the binary variable$Y$ (0 or 1), representing the connection or absence of connection of new turbines to the grid in Denmark for each month.

Electricity price data come from NordPool. Monthly averages are calculated from hourly data on working days[5] only from 1999 to 2010[6]. Monthly averages are corrected for inflation[7] so that all figures are in constant €2000. Electricity price data are reported in Annex 2.

The support variable is defined as the premium of the policy under which turbines are connected to the grid each month, including the 3€ allowance for balancing costs mentioned in part 2. When the premium takes the form of a feed-in tariff, the support variable is the difference between the feed-in tariff and the electricity price. When the fixed premium is limited by the electricity price, it is classified as a variable premium with values as determined by the electricity price, as explained below. As is done for the electricity price, the support premium is corrected for inflation so that all figures are in constant €2000. For the time period after February 21st 2008, the support, before correction for inflation, is defined as 37€/MWh corresponding to 34€/MWh of fixed premium in addition to 3€ for balancing cost allowance. For the time period from 2005 to February 20th 2008, the support variable is defined as 16€/MWh corresponding to 13€/MWh of fixed premium and 3€ for balancing cost allowance. For the time period 2003-2004, given the variable premium policy presented in part 3, three cases are considered. For the months for which electricity price is above 48€/MWh, the support variable is defined as 3€/MWh (balancing cost allowance only). For the months for which electricity price is below 35€/MWh, the support variable is defined as 16€/MWh corresponding to 13€ of premium and 3€ of balancing costs allowance. For the months for which electricity price is between 35 and 48€/MWh, the support is defined as the difference between electricity price and 48€ in addition to the 3€ allowance for balancing costs. Finally, for the feed-in tariff period (2000-2002), the support variable is defined as the difference between electricity price and 61€/MWh (sum of 58€/MWh of feed-in tariff and 3€/MWh allowance for balancing costs). Electricity price is never above 61€/MWh in that time-period.

---

5 Data on working days only are used instead of data on all days, as the latter are available from 2002 only while the former are available from 1999. Regressions were run on the time period 2002-2010 with the two electricity price series. No significant difference was observed. Average is done on available data: West Denmark only from 01/07/1999 to 28/09/2000 and West and East Denmark from 29/9/2000.

6 The comparison between the averages on electricity price when weighted with hourly wind power production (hourly wind power production data are found on energinet.dk) and the simple averages proved that the difference between them was not significant. This allowed taking simple averages in the econometric analysis.

7 Inflation data from International Monetary Fund, World Economic Outlook Database, end of period consumer prices.

For the cost term, yearly wind power investment cost indications from the European Wind Energy Association are used as a proxy (Moccia, Arapogianni, Wilkes, Kjaer, Gruet, Azau, Scola, and Bianchin, 2011).

Regarding endogeneity concerns, Y might have an impact on $elecprice_t$ without lag. For the premium time period (after 2002), this is not a problem since what is tested in the analysis is the possible impact of electricity price projections at the date when the decision to build a turbine is made. These electricity price projections are based on past electricity prices. Y cannot have an impact on past electricity prices due to the causality principle. Also, in this time period, endogeneity concerns between Y and the support are also excluded since Y is defined monthly as the presence or absence of connections of new turbines to the grid each month while the support policy changes every two or three years. In the FIT time period (2000-2002), $support_t$ is computed from $elecprice_t$ and there could be endogeneity between Y and the support. However the feed-in tariff does provide a premium and the question remains whether the level of implicit premium matters. The dummy variable FIT helps to control for this situation. Regressions were run on the post-FIT period (after 2002) and the main results from the regression on the whole time period remain robust on the post 2002 period as well (this point is discussed in part 3.5). The correlation table is given in given in Annex 1.

The database does not take account of particularly small turbines (turbine capacity less than 20kW or hub height less than 20m). Heteroscedasticity is corrected for all regressions.

2.4 Results and Interpretation

Regression coefficient results are presented in Table 2. Figure 2 illustrates the probability distribution they quantify and helps to understand and interpret their values. Robustness of these results is discussed in part 3.5. It is found that past electricity prices have no impact on the decisions to connect new turbines to the grid and that the dominant parameter is the support level. The support policy type also matters as the regressions show that a feed-in tariff significantly brings more wind power in than a premium policy. No clear difference is observed between the impacts of a fixed and a variable premium on the decision to connect new turbines. The cost term impact is dominated by the support and FIT impacts.

Table 2 - Probit regression of the Observation or Absence of Observation of New Turbines Connections to the Grid[8]

	(1)	(2)	(3)	(4)	(5)
elecprice (-12)	0,0223	0,0195			
	1,66	*1,38*			
elecprice(-24)			0,0142	0,0092	0,0097
			0,99	*0,62*	*0,66*
support	0,0556***	0,0729***	0,0561***	0,074***	0,073***
	3,33	*3,67*	*3,13*	*3,7*	*0,02*
VP	0,1376	0,2583	0,1791	0,2723	0,6280
	0,4	*0,72*	*0,49*	*0,72*	*0,66*
FIT	1,3625**	3,8439***	1,492**	10,4628***	10,7***
	2,57	*4,23*	*2,25*	*3,13*	*3,19*
*support*FIT*		-0,0811***		-0,2629***	-0,255***
		-2,72		*-2,7*	*-2,68*
cost					0,001
					0,43
constant	-2,1716***	-2,4466***	-1,8769***	-2,0896***	-3,666
	-3,48	*-3,69*	*-3,13*	*-3,26*	*-0,97*
Wald χ^2	27,81***	40,27***	19,41***	47,07***	49,29***
Pseudo R^2	0,2812	0,3	0,2363	0,2667	0,268
Observations	122	122	110	110	110

Table 2 presents the results of five different regressions of Y, the presence or absence of new turbine connections to the grid, on electricity price lagged by 12 or 24 months, the support variable, the cost variable, the dummy variables and the interaction term between $support_t$ and FIT. Lags for electricity prices are tested from six months to five years. Results for one or two-year-lags only are presented. Regressions (1) and (2) use a twelve-month-lag for electricity price while regressions (3) and (4) use a two-year lag for electricity prices. Regressions (2) and (4) include the interaction term between $support_t$ and the dummy variable FIT while regressions (1) and (3) do not. Regression (5) includes the cost term.

Past electricity prices do not have a significant impact on Y. The estimated coefficient associated with the support variable is always significant (the associated z-value is above 2 and the p-value is below 1%). The support level has a clear impact on the decision to build and connect new turbines to the grid.

The policy type impact is tested through the dummy variables FIT and VP, with or without the interaction term. The reference category is the fixed premium regime. The interaction term between $FIT$and the support variable is tested while the interaction term between VP and $support_t$ is not. The reason is that, given the data, the latter is nearly collinear with the dummy variable VP alone so that it is not meaningful to include it in the regression. It is found that a feed-in tariff regime has a significantly higher impact on wind power deployment than a fixed premium regime. The coefficients associated with FIT and with the corresponding interaction term are always significant. This means that, under a feed-in tariff regime, the probability of observing new turbines connections to the grid is larger than under a premium regime, for the same equivalent level of support.

[8] The z-value corresponding to each coefficient is indicated in italic below the coefficient value. ***, **, and * respectively indicate a 1, 5 or 10 % significance level.

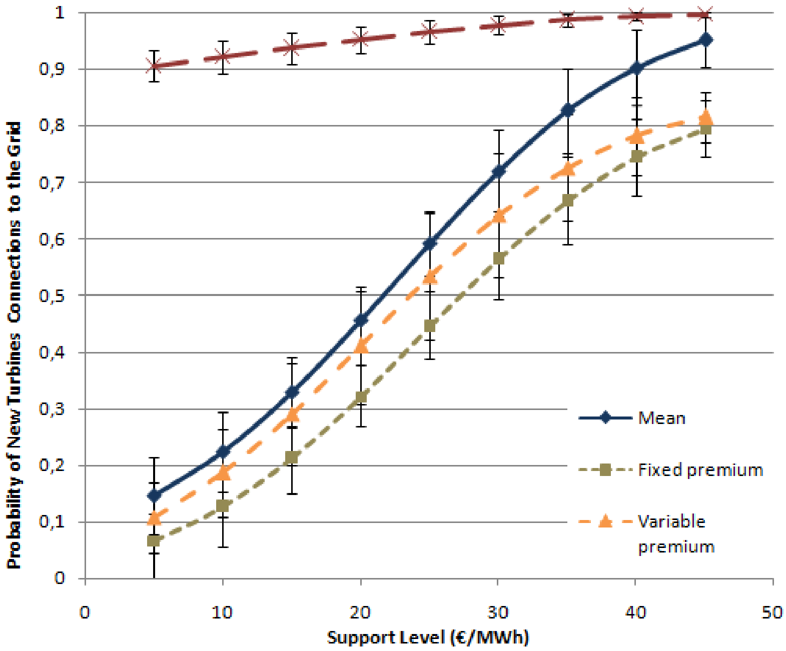
Regarding the cost variable impact, correlation between the variables FIT and $cost_t$ leads to multicollinearity issues. However tests on the inclusion of the cost term in regressions (1) to (4) showed that its impact is dominated by the impact of FIT.

To interpret the coefficients from this discrete choice model econometric analysis, the marginal effects of each relevant variable (variables associated with significant coefficients in the regressions above) are computed and the predicted probability of new turbine connections to the grid is plotted as a function of the support and the policy type (Figure 2). The choice is made to present the graph associated with regression (4) but robustness of the curves as a function of the regression chosen is discussed in part 3.5. For the *"Mean"* curve, the value at each point is the averaged predicted probability calculated using the specific value for the support variable and the sample values of the other predictor variables[9]. For the *"Feed-in tariff"*, *"Variable premium"* and *"Fixed premium"* curves, the predicted probability of having new connections depending on the policy type is computed for each support level.

This shows that the probability of investment increases with the level of support regardless of the form it takes. This form makes a considerable difference with the feed-in tariff increasing probability considerably. The extra benefit of this form diminishes as the support level increases. The *"Mean"* curve shows that, on average, the probability of observing new turbine connections to the grid is 50% for a support level of 22€/MWh. Under a feed-in tariff regime, the probability is higher for the same support level, while it is lower under a premium policy. For example, for a support level of 30€/MWh, the probability of new connections is 0.72 on average, but it is above 0.88 under a feed-in tariff regime. *"Fixed premium"* and *"Variable premium"* curves are not significantly different. For the *"Feed-in tariff"* curve, the part of the curve corresponding to support values below 30€/MWh is not robust as it is nearly an out-of-sample extrapolation (for the feed-in tariff period, the support variable is above 30€/MWh except for two months).

[9] For each point of the *"Mean"* curve, the regression coefficients are used to calculate a probability for each observation, taking into account the specific value for the support variable and the values of the other predictor variables for this observation. Then these probabilities for all observations are averaged to give the value that appears on the curve (ex: 0.14 for a support level of 5€/MWh).

Figure 2 - Probability of new turbine connections to the grid as a function of the support policy level and the policy type



In conclusion, these results indicate that the dominant parameter for the decision to connect new turbines to the grid is the support level. The support policy type also matters as a feed-in tariff policy brings in more wind power than a premium regime. No difference is observed between a fixed and a variable premium regime. On average a support level of 22€/MWh[10]in addition to electricity price leads to a probability of 0.5 to observe connections of new turbines to the grid.

2.5 Robustness Analysis

In this part, the robustness of the results presented before is discussed. First the threshold value of 22€/MWh as the support level needed to observe new turbines connections to the grid with a probability of 50% is robust. Depending on the regression chosen, this value varies between 19 and 22€/MWh. Then, regarding the changes in the curves presented before, as a function of the regression that is chosen, the *"Mean"*, *"Variable premium"* and *"Fixed premium"*curves are robust as well as the part of the *"Feed-in tariff"* curve above 30€/MWh, but the part of the *"Feed-in tariff"* curve below 30€/MWh is not. The ranges of probability for each curve at 5, 25 and 45€/MWh are presented in Table 3. These ranges take account of the standard errors defined when computing the predicted probability as a function of the support level and the support policy type, for each regression. This confirms the fact that a variable premium policy does not have a significantly different impact than a fixed premium policy. Despite the fact that the part of the *"Feed-in tariff"* curve for low support level is not robust, the feed-in tariff regime still does bring more wind power in than other schemes.

Regressions were also done on the post FIT period (after 2002), to test the relative impact of the support and electricity price if the analysis is done on these years only. Support remains the dominant factor and past electricity prices do not have a significant and robust impact. In addition, the support level for which the probability of observing new turbines connection to the grid is 0.5 remains in the range indicated by the regressions on the whole time period, that is to say, between 19 and 22€/MWh.

[10] All support level figures indicated from the regression results are in constant €2000.

Table 3 – Ranges of predicted probabilities of observing new connections of turbines to the grid, as a function of the support level and the policy type and for all regressions reported in part 3.4

Support level	*5 €/MWh*	*25 €/MWh*	*45 €/MWh*
Mean	0,055-0,32	0,52-0,65	0,81-1,00
FP	0,021-0,19	0,35-0,56	0,67-0,96
VP	0,045-0,25	0,38-0,68	0,70-1,00
FIT	0,33-0,93	0,81-1,01	0,98-1,00

3. Carbon Price Level Deduction

The probit regressions presented in part 3 indicate that, on average, a support of 22€/MWh leads to a probability of 0.5 to observe new connections of turbines to the grid. Past electricity prices do not have significant impact while support level and support policy type clearly matter. Given these results, conclusions can be inferred on the carbon price level that would provide comparable price advantage to wind power as the support policies that attain wind deployment. The idea supporting these conclusions is the equivalence between carbon price and renewable support policies to cover cost difference between renewable and conventional technologies. It is presented below.

3.1 Carbon Price Equivalence model

The comparison of the profit functions between renewable and fossil technologies shows how the premium paid as a support to renewable energy can be seen as equivalent to a carbon price. It then covers the cost difference between renewable and conventional technologies.

As presented in part 3.1, the profit function π_i for energy technology i is defined as:

$$\pi_i = P_e + X_i - C_i - E_i \text{ with } X_i \geq 0.$$

For a renewable technology r, there is no emission cost and the profit function is:

$$\pi_r = P_r + X_r - C_r \text{ with } X_r \geq 0$$

For a fossil fuel technology f, the electricity producer receives no premium and the profit function is:

$$\pi_f = P_f - C_f - E_f \text{ with } E_f \geq 0$$

The condition for the renewable technology to be more profitable than the fossil technology is $\pi_r > \pi_f$, which is equivalent to:

$$P_r + X_r - C_r > P_f - C_f - E_f \text{ with } C_r - C_f > 0.$$

Under the assumption that $P_f = P_r$, the previous inequality leads to :

$$X_e + E_f > C_r - C_f \text{ with } X_e \geq 0 \text{ and } E_f \geq 0.$$

This inequality shows that X_e and E_f are additive and therefore equivalent regarding the profitability difference between renewable and fossil technologies.

3.2 Carbon Price Inference from Regression Results

If we assume that electricity production from coal emits 0.85 tons of CO_2/MWh (Sijm, Neuhoff, and Chen, 2006) and that electricity production from gas (combined cycle) emits 0.48 tons of CO_2/MWh, the indication of 22€/MWh as the support needed to have a probability of 0.5 to observe new connections of turbines to the grid is then equivalent to a carbon price of 26€/ton if competing with electricity production from coal or 46€/ton if competing with electricity production from gas. This is under the assumption of revenue certainty equivalence[11]. In other words, at 26€/ton, the carbon price provides a price advantage to wind energy over electricity production from coal that is comparable to the advantage of the support level needed to see new connections of turbines to the grid with probability 0.5. If competing with electricity production from gas (combined cycle), these equivalence is reached for a carbon price of 46€/ton.

Conclusion

The purpose of the work presented here is to use the Danish experience to conduct an empirical analysis of the conditions of renewable energy deployment in order to infer a carbon price level that would provide a price advantage to wind energy over fossil fuel technologies comparable to the advantage provided by existing support policies. The analysis is focused on on-shore wind power in the time period from 2000 to 2010. A discrete choice econometric technique is used to test the impact of electricity price, support policy and support level on the observation of connection of new turbines to the grid, on a monthly basis.

The analysis shows that support level is the dominant parameter and that a feed-in tariff policy has a significantly larger impact than a premium policy. A variable premium does not have a significantly different impact compared to a fixed premium. Under a premium policy, past electricity prices have a minor effect that is overwhelmed by the support level impact. Initial investment cost is also dominated by the support and the feed-in tariff impacts. The probit analysis indicates that, on average, a 22€/MWh support in addition to electricity price is necessary to observe connections of new turbines to the grid with a probability of 0.5.

Inference on the carbon price level is based on the equivalence between a support premium and a carbon price to cover the cost differences between renewable and fossil fuel technologies. Under certainty revenue equivalence, the support level of 22€/MWh indicated above can be converted into an equivalent carbon price of 26€/ton if renewable energy competes with electricity production from coal or 46€/ton if it competes with electricity production from gas.

A limit of this work is that Denmark is a very specific country regarding wind power. Hence it would be interesting to conduct similar analysis on other European countries to be able to draw conclusions on the potential impact of the European carbon market on wind power deployment in all member states.

[11] This is a strong assumption. Previous analysis demonstrated the importance of long range energy policy in stabilizing the conditions required for renewable energy development (Meyer, 2007). A carbon price alone may not provide revenue certainty equivalence under some of the support policies. More work on uncertainty and wind power investment could be done, based on more general research on uncertainty and irreversible investment, for example as C.A. Favero, M.H. Pesaran and S. Sharma on oilfields (Favero, Pesaran and Sharma, 1992).

References

Blanco, M. I., Rodrigues, G., 2008. Can the future EU ETS support wind energy investments?. Energy Policy. 36(4):1509-1520.

Bolinger, M., Wiser, R., 2011. Understanding trends in wind turbine prices over the past decade. Ernest Orlando Lawrence Berkeley National Laboratory, LBNL-5119E. http://eetd.lbl.gov/ea/ems/reports/lbnl-5119e.pdf.

Couture, T.D., Cory, K., Kreycik, C., Williams, E., 2010. A policymaker's guide to feed-in tariff policy design. National Renewable Energy Laboratory, Tech. Rep. NREL/TP-6A2-44849.

Energistyrelsen. The history of Danish support for wind power. www.ens.dk.

Favero, C. A., Pesaran, M. H., Sharma, S., 1992. Uncertainty and irreversible investment: an empirical analysis of development of oilfields on the UKCS. Oxford Institute for Energy Studies, EE17.

Jauréguy-Naudin, M., 2010. Wind power, a victim of policy and politics", Institut Français des Relations Internationales, Note de l'IFRI. http://www.ifri.org/?page=detail-contribution&id=6246.

Menz, F. C., Vachon, S., 2006. The effectiveness of different policy regimes for promoting wind power: Experiences from the states. Energy Policy, 34(14):1786-1796.

Meyer, N. I., 2007. Learning from wind energy policy in the EU: lessons from Denmark, Sweden and Spain. European Environment, 17(5):347-362.

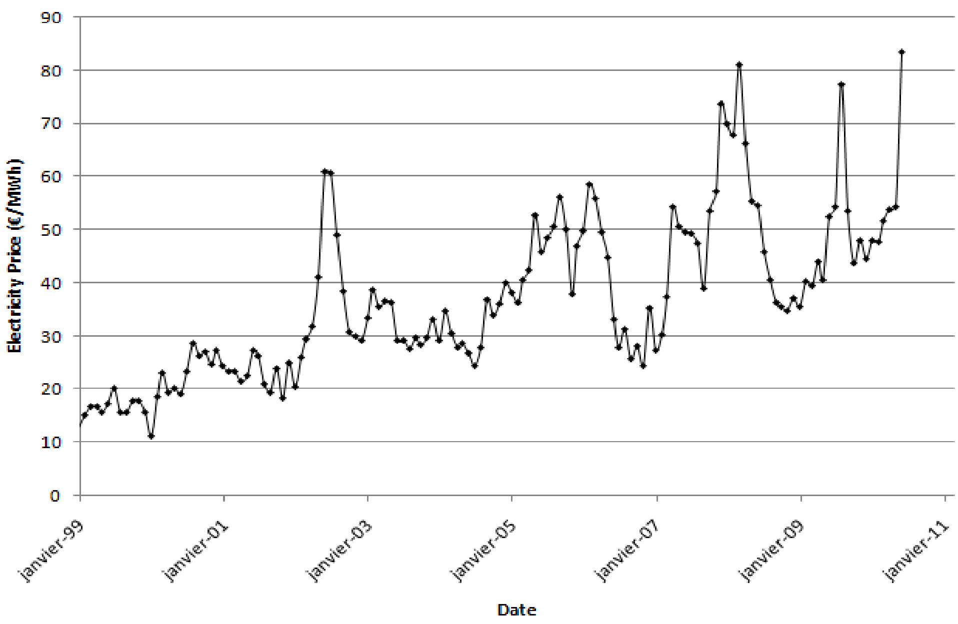
Moccia, J., Arapogianni, A., Wilkes, J., Kjaer, C., Gruet, R., Azau, S., Scola, J., Bianchin, R., 2011. Pure power, wind energy targets for 2020 and 2030. European Wind Energy Association. http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/Pure_Power_Full_Report.pdf.

Sijm, J., Neuhoff, K., Chen, Y., 2006. CO_2 cost pass-through and windfall profits in the power sector. Climate Policy, 6(1):49-72.

Annex 1 - Correlation table of the variables used in the regressions

	Y	*elecprice (-12)*	*elecprice (-24)*	*support*	*VP*	*FIT*	*support*FIT*	*cost*
Y	1							
elecprice (-12)	0,0312	1						
elecprice (-24)	-0,0424	0,1486	1					
support	0,4944	-0,0275	-0,0131	1				
VP	-0,2105	-0,0935	-0,2236	-0,4425	1			
FIT	0,4013	-0,4231	-0,5234	0,5075	-0,2337	1		
*support*FIT*	0,3751	-0,4111	-0,5126	0,6014	-0,223	0,9543	1	
cost	-0,1879	0,5161	0,5817	-0,1117	-0,4785	-0,698	-0,6571	1

Annex 2 - Nominal electricity price in Denmark[12]



[12] Monthly averages are calculated from Nordpool hourly data on working days and corrected for inflation.

Author contacts:

Claire Gavard

Centre d'Economie de la Sorbonne

Maison des Sciences Economiques

106-112 boulevard de l'Hôpital

75647 Paris Cedex 13

France

Email: claire.gavard@polytechnique.edu

European
University
Institute

European University Press