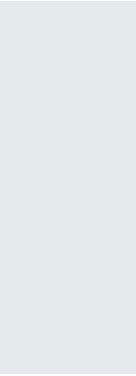


economics for energy



Renewable Energy and Electricity Prices in Spain

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Abstract

Growing concerns about climate change and energy dependence are driving specific policies to support renewable or more efficient energy sources in many regions, particularly in the production of electricity. These policies have a non-negligible cost, and therefore a careful assessment of their impacts seems necessary. In particular, one of the most-debated impacts is their effect on electricity prices, for which there have been some *ex-ante* studies, but few *ex-post* studies. This article presents a full *ex-post* empirical analysis, by looking at use of technologies and hourly electricity prices for 2005-2009 in Spain, to study the effects that the introduction of renewable electricity and cogeneration has had on wholesale electricity prices. It is particularly interesting to perform this study in Spain where an active system of public support to renewables and cogeneration has led to a considerable expansion of these energy sources and electricity pricing is at the centre of intense debate. The paper reports that a marginal increase of 1 GWh of electricity production using renewables and cogeneration is associated with a reduction of almost 2 € per MWh in electricity prices (around 4% of the average price for the analyzed period).

Keywords: prices, renewables, electricity, supply, Spain

JEL classification: Q41, Q42

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1. Introduction

Renewable energy and efficient cogeneration are major technological alternatives to fight against climate change and energy dependence; therefore, many developed and developing countries are considering large increases in their contribution to the energy mix. The European Union is trying to play a leading role with its Climate Action program, which has set as a target to provide 20% of the total primary energy with renewable energies. Other regions in the world are also following suit.

However, this expected increase in renewable energy targets is also creating great debate about its costs. When targets were quite small, the impacts of renewable energy policies on the budget or the electricity tariff were also limited. This helped to make them well accepted. Yet the large increase which is to take place in the coming years brings about concerns on how the cost of these policies may affect electricity prices and, subsequently, the competitiveness of large energy consumers, inflation or distributional indicators. This has prompted many studies and analysis on, among other things, the costs and benefits of renewable energy policies.

One of the most prominent lines of research attempts to look at the impact of an increased renewable energy target on electricity prices. The general understanding, as first proposed by Jensen and Skytte (2002), is that an increase in renewable energy penetration should lower electricity prices. If the decrease in electricity prices is significant enough, it may well compensate the cost of renewable energy promotion, given that the decrease in electricity prices extends to all electricity producers.

Let us first note that this decrease in electricity prices is not necessarily a welfare-enhancing process, but rather an actual transfer between consumers and traditional producers. However, under political economy considerations and distributional concerns, this potential reduction of electricity prices is very appealing from a political point of view. Indeed, it is being used as an argument for or against the deployment of renewable energy in many energy debates all over the world. We, therefore, consider that it deserves careful study.

So far, academic efforts in the field have focused on two types of analysis: theoretical, and simulation. The theoretical models include those developed by Amundsen and Mortensen (2001), Jensen and Skytte (2002) and Fisher (2006). They all conclude, as hinted above, that there should be a decrease in wholesale electricity prices because of the introduction of renewable energy promotion policies. The simulations performed by Sensfuss et al (2008) or Linares, Santos and Ventosa (2008) have confirmed these results.

Unfortunately, these studies have not contemplated two important features of the effect of renewables on electricity prices. First, that this effect should just be temporary: when the decrease in electricity prices takes place, it reduces the long-term signal for investment and thus deters future investments, bringing about a subsequent increase in electricity prices due to restricted supply. In addition, when market power exists, traditional producers may bid higher in order to maintain the price level. These two elements are difficult to predict in theoretical analyses, where many assumptions have to be made about these issues. Hence, the actual relevance of these features may only be revealed through the analysis of real markets.

Despite the relevance of the question and the growing availability of real data, very little research has been carried out through ex-post empirical analysis. The only studies we have been able to identify in this area are those by Sáenz de Miera et al (2008), which looks at the impact of wind energy production on Spanish electricity prices, and Rathmann (2007) on the German electricity system. In Spain, Sáenz de Miera et al (2008) estimate a market price reduction of 11.7%, 8.6% and 25.1% in 2005, 2006 and 2007 respectively. However, those two papers only analyze a partial set of data which makes their results difficult to generalize. More recently, Jonsson et al (2010) have looked more carefully into the impact of wind energy forecasts on spot prices in Denmark. Their approach is closer to the one we present here, although their major objective is to forecast spot prices rather than to explain the change due to wind energy penetration. Again, they only examine one year.

In this article we carry out a full ex-post empirical analysis, by looking at use of technologies and hourly prices between 2005 and 2009 to provide a more general understanding of the actual effect of the introduction of renewable sources of energy

and cogeneration on the Spanish wholesale electricity prices. We believe that it is particularly interesting to perform this empirical study in Spain where electricity pricing is currently at the centre of intense social and regulatory debate. Moreover, an active system to support renewables has been in place in Spain since the 1990s which has led to a considerable expansion of these energy sources.

The paper is organized in three further sections. In section 2 we present the Spanish electricity system and the framework for renewable energy support; in section 3 we describe the data and econometric methods used; in section 4 we report the results which are discussed in the final section.

2. The Spanish electricity market and its renewable policy

The Spanish electricity mix is basically 10-15% hydro (depending on rainfall), 20% nuclear, 15% coal (both imported and domestic, the latter including black and brown lignite), and 25% combined cycles. Renewables and cogeneration (not including hydro) contribute with 30% of the total demand, and are expected to grow up to 40%. The market is a rather concentrated one, with two large firms covering a large part of the generation market and only four more small firms with some generation capacity, which cover the rest of the market. More information about the Spanish electricity system and its expected evolution may be found in Linares, Santos and Pérez-Arriaga (2008).

Spain established the first feed-in tariff system to support electricity produced from renewables and cogeneration in 1994, which has since been the major support mechanism for these technologies in the country. This feed-in tariff also included obligating distribution companies to buy all renewable and cogeneration electricity produced, and obligating the system operator to dispatch it with the highest priority. With time, the system has been adjusted. First (in 1998) an option was included so that renewable energy producers might bid to the wholesale market and they were incentivized to do so. By doing this, they would receive the market price, plus a premium. Since then, and this is an interesting feature of the Spanish support system, a large share of wind power plants bid to the market (93% in 2007 and 2008, although lower market prices have, in turn, brought this figure slightly down). This large

participation will allow us to study the impact of the penetration of renewable and cogeneration on wholesale market prices, given that most renewable and cogeneration producers are bidding into this market.

In 2004, another modification guaranteed perceiving the feed-in tariff or the premium for the whole economic lifetime of the power plant (usually with a decreasing factor). In addition, balancing payments were required from some of the renewable producers. Another important change was the increase of the maximum size of solar photovoltaic (PV) plants able to receive the maximum premium, which jumpstarted the building of large (up to 5-10 MW) PV plants. In 2007 the system was again modified when a cap-and-floor system was introduced for wind energy producers bidding in the wholesale market

As for the amount of the premiums, Table 1 shows the average premium perceived per MWh. It should be added that for solar PV the premium in 2010 was reduced to 240 €/MWh. These premiums cover more than the operation and maintenance (O&M) costs and this allows renewable energy producers to bid into the market at zero prices. The dispatch priority will eventually displace other, non-renewable technologies from the wholesale market and this will eventually bring down electricity prices.

Insert Table 1 here

This support system has proven very successful, at least for some technologies, in promoting investments. Spain has become a world leader in installed renewable energy, particularly wind and solar energies. Currently, renewable electricity plants produce more than 56,000 MWh per year (more than 20% of the total electricity demand). Figure 1 shows the evolution of the renewable installed capacity.

Insert Figure 1 here

This large development of wind and particularly solar energy has, of course, come at a non-negligible monetary cost for consumers. Solar energy has received significant support and wind energy has been produced in large amounts. This has contributed to a relevant fraction of the total electricity tariff. In 2009 the total support for renewables and cogeneration was 4,600 m € (17% of the total cost of the power system in Spain). As may be seen in Figure 2, over half of this corresponds to solar energy (which is also the strongest growing concept).

Insert Figure 2 here

Now, the question is whether this significant deployment has also brought about a reduction in electricity prices, which could even compensate for this cost, as predicted theoretically. This is what we set out to do in the next section, where we estimate the impact of the increased participation of renewables and cogeneration on wholesale market prices. From now on we will refer jointly to these two technologies, renewables and cogeneration, as “special regime”¹, according to the Spanish legislation.

3. Data and methods

We use a multivariate regression model to estimate the average effect of a marginal change in the special regime on electricity prices in Spain between 2005 and 2009². Although prices and data are usually generated on an hourly basis, we will use a daily average to reduce unwanted noise, i.e. the influence of events that may take place in a particular hour and that are temporary and exceptional.

To model daily electricity prices we use as explanatory variables the daily demand for electricity ($TOTDEM_t$) and the daily composition of electricity production by energy

¹ See Royal Decree 661/2007 for a description of its regulation. One of the key components of the special regime is electricity generation through renewable sources of energy.

² Data on electricity generation by energy source were obtained from OMEL (Operador del Mercado Eléctrico Español) and Red Eléctrica de España (REE). Final electricity prices were obtained from OMEL.

source, that is, the electricity produced from renewables and cogeneration under the special regime ($SPREGIME_t$)³, total production by hydro plants ($HIDRO_t$), nuclear plants ($NUCLEAR_t$), combined cycle plants ($COMBCYCLE_t$) and from fuel or natural gas plants ($FUELGAS_t$). Although hydro generation is also a renewable energy source, we do not aggregate it with the special regime because the use of water, which can be regulated and therefore shifted in time to profit from higher prices, has a positive opportunity cost, and so the impact of hydro production on electricity prices is expected to be different to those from energy sources under the special regime. Finally, we define the variable ($OTHER_t$) as the sum of net electricity exports, pumping and distribution losses. In other terms, this variable is the difference between total generation and total demand.

Before proceeding to estimate the model (that we describe next), we tested for the existence of unit roots in the above-mentioned time series included in the analysis using the augmented Dickey-Fuller (ADF) test (Dickey and Fuller, 1979) and used two approaches to determine the number of lags to be included in the model in order to eliminate correlation in the residuals. We follow Banerjee et al (1993), who suggests the optimal number of lags (p) to be $p = \text{int} [12(T/100)^{1/4}]$, where T is the total number of observations, and we also search for the number of lags such that the R^2 is maximized, while minimizing at the same time the Akaike Information Criterion and use the Durbin Watson statistic (Durbin and Watson, 1950) to check for first order autocorrelation in the residuals. We included a trend in the specification of the model in those cases where it was significant. The results of the ADF tests, which are discussed in more detail in the next section, indicate that some of the series are $I(1)$ so we estimate the model in first daily differences. Under weak dependence of the variables in differences, zero conditional mean of the residuals and exogenous regressors, OLS estimates using time series data are consistent (Wooldridge, 2003).

In order to control for the well-known seasonality of electricity prices, the model includes, in addition to a constant, six dummy variables indicating the day of the week (Monday to Saturday) and eleven dummy variables indicating the month (January to

³ For future research we would like to obtain disaggregated information of the different technologies under the special regime to be able to exclude electricity production from cogeneration, as it has significantly higher variable costs than the rest of the special regime and therefore a different impact on electricity prices. However we have not been able to obtain these data for the current analysis.

November). We also include four annual dummies to control for factors without annual variation that may be associated with changes in electricity prices.

We thus estimate the following two models,

$$\begin{aligned} \Delta ELECPRICE_t = & \beta_0 + \beta_1 \Delta TOTDEM_t + \beta_2 \Delta SPREGIME_t + \sum_{k=1}^6 \beta_{k+2} dd_{kt} \\ & + \sum_{l=1}^{11} \beta_{l+8} dm_{lt} + \sum_{s=1}^4 \beta_{s+19} dy_{st} + u_t \end{aligned} \quad (1)$$

$$\begin{aligned} \Delta ELECPRICE_t = & \beta_0 + \beta_1 \Delta SPREGIME_t + \beta_2 \Delta HIDRO_t + \beta_3 \Delta NUCLEAR_t + \beta_4 \Delta CARBON_t \\ & + \beta_5 \Delta COMBCYCLE_t + \beta_6 \Delta FUELGAS_t + \beta_7 \Delta OTHER_t + \sum_{k=1}^6 \beta_{k+7} dd_{kt} \\ & + \sum_{l=1}^{11} \beta_{l+13} dm_{lt} + \sum_{s=1}^4 \beta_{s+24} dy_{st} + u_t \end{aligned} \quad (2)$$

where Δ represents the first difference operator, dd_{kt} ($k = 1, \dots, 6$) are daily dummies, dm_{lt} ($l = 1, \dots, 11$) are monthly dummies and dy_{st} ($s = 1, \dots, 4$) are annual dummies. In the next section we explain the interpretation of the estimated coefficients of each of the models.

We use Durbin's alternative statistic (Durbin, 1970) to test for the existence of serial correlation in the OLS residuals. The test is valid whether there is any number of non-strictly exogenous explanatory variables or not and it can be used to test for AR(1) and higher orders of serial correlation. We follow Newey and West (1987) to obtain heteroscedastic and serially correlated robust standard errors for all the OLS estimates reported. In general there is little theoretical guidance on how to determine the form of the serial correlation in computing the standard error. We follow Newey and West (1987) recommendation on the number of lags (L) to be included and compute the robust standard errors taking L as the integer part of $4(T/100)^{1/4}$, with T being the total number of observations. Results are qualitatively unchanged if we take L as the integer part of $T^{1/4}$ as other authors suggest (Greene, 2008).

Given the collinearity between some of the explanatory variables included in the model, we also test for the existence of multicollinearity using the Variance Inflation Indicator.

4. Results

Table 2 reports descriptive statistics of the variables included in the analysis for the whole period and for each of the five years. There is a significant drop both in the level and volatility of electricity prices after 2006 (see Figure 3)⁴.

Insert Table 2 here

Insert Figure 3 here

Concerning the evolution of electricity generation by energy source, all the energy sources report positive uses every day during the period under analysis. The most important changes in the technological composition of electricity generation are the increase in the contribution of the special regime and the combined cycle in detriment of coal and fuel/gas plants. More precisely, the contribution of the special regime increases from around 19.6% in 2005 to 32.1% in 2009 and the combined cycle from around 18.7% to almost 24.5%. At the same time, the contribution of coal decreases from 28.8% in 2005 to 12% in 2009 and fuel/gas plants also reduce their contribution from around 4.3% in 2005 to less than 1% in 2009. Finally, the relative contribution of hydro plants fluctuates between 7% and almost 11% while for nuclear plants it remains quite constant at around 20% during the five years considered in this analysis.

⁴ The annual dummies included in the model account for the change in the average level of electricity prices while, since heteroscedasticity only affects the efficiency of the estimates, it is controlled for by correcting the OLS standard errors following Newey and West (1987).

Before turning to the results of the OLS estimations, just a few comments on the correlation matrix of the variables included in the analysis, reported in Table 3. As expected, daily changes in the use of electricity under the special regime are negatively correlated with daily changes in the electricity price. However, the correlation is positive for changes in the production of hydroelectricity. This is consistent with the fact that, although the variable costs for this technology are low, production from hydro plants is typically associated with periods of high demand, since hydro plants can be regulated and indeed used to equalize marginal costs for producers. Thus we observe a positive correlation between changes in production by hydro plants and changes in prices. In fact, the correlation with changes in demand is strong as it is also for electricity production from combined cycle plants.

Insert Table 3 here

Table 4 reports the ADF test results of the variables in levels and in first differences. The results for the variables in levels indicate that we cannot reject the existence of a unit root for electricity prices (*ELECPPRICE*), production by plants under the special regime (*SPREGIME*), production by coal plants (*COAL*) and production by combined cycle plants (*COMBCYCLE*). The results of the ADF test on the first difference of these variables indicate that they are I(1) in levels.

Insert Table 4 here

The OLS estimates of the specified model are reported in Table 5. Given that the alternative Durbin's statistic indicates the existence of serial correlation in the disturbances, all the estimated models report Newey and West (1987) robust standard errors. Model (1) only includes the time dummies, which alone explain 30% of the daily variation in electricity prices. Specification (2) incorporates the daily changes in total demand, which significantly increase the explanatory power of the model. As expected, a marginal increase in total demand is associated with a positive change in electricity

prices. In model (3) we include the central variable of interest, that is, total electricity production under the special regime [see equation (1)]. Again, the explanatory power of the model increases significantly. As expected, model 3 shows that an increase in the generation of electricity from energy sources under the special regime reduces the price of electricity. More precisely, for any given level of electricity demand, if electricity production under the special regime increases by 1 GWh, electricity prices decrease on average by around 1.9 € [with a 95% confidence interval of (-2.09, -1.65)]. Given an average electricity price of 52.4 € per MWh for the period under analysis, this effect represents a price reduction of around 3.7%. Considering that the average hourly demand of electricity for the period under analysis was 29,100 GWh, the estimated marginal effect represents an average annual aggregate reduction of around 478.2 m € in the cost of electricity⁵.

Insert Table 5 here

Interestingly, the marginal effect of electricity generation under the special regime estimated in Model 3 becomes lower as we consider more recent years. In fact, if we estimate Model 3 in Table 5 for each of the analyzed years (results are not reported but are available from the authors upon request) we find that an increase of a 1 GWh in electricity production under the special regime reduces electricity prices by 3.8 € in 2005, by 3.4 € in 2006, by 1.7 € in 2007, by 1.5 € in 2008 and by 1.1 € in 2009. These estimated marginal effects represent average annual aggregate savings of around 940.2 m € for 2005, 846.6 m € for 2006, 445.4 m € for 2007, 395.8 m € for 2008 and 278.3 m € for 2009. This may be explained by the increased participation of combined cycles, which results in flatter price profiles and, therefore, in reduced opportunities for price reduction.

As we described in the previous section, in the absence of market power, an increase in renewable energy penetration should reduce electricity prices because of its lower

⁵ Given that the marginal effect of an increase in electricity generation under the special regime on electricity prices was estimated at 1.876 €/MWh, the average annual cost saving resulting from this effect is calculated as follows: 29,100 (Average hourly demand in MWh) x 24 (hours/day) x 365 (days/year) x 1.876 (€/MWh).

relative marginal cost. In addition, when demand is high, the electricity price is determined by the costs of a high-marginal-cost technology, while when demand is low the price is determined by the marginal cost of a cheaper technology. As a result, we expect electricity generation under the special regime to have a stronger negative effect on electricity prices when demand is high since, in these scenarios, the technologies under the special regime are substituting technologies with a higher marginal cost. To empirically explore this issue we re-estimate Model 3 in Table 5 restricting the sample to the observations in the first and last demand quartiles. The results, which are reported in Table 6, confirm our predictions. While a 1 GWh increase in electricity production under the special regime decreases electricity prices by almost 1.5 € in the lowest demand quartile, it decreases electricity prices by 2.2 € in the highest demand quartile. That is, the negative effect is almost 50% stronger in the subsample of days with highest demand with respect to the one with the lowest demand.

 Insert Table 6 here

Finally, in Model (4) we exclude the variable *TOTDEM* and incorporate all the other components of the demand, which are *COAL*, *COMBCYCLE*, *HYDRO*, *NUCLEAR*, *FUELGAS*, and *OTHER* [see equation (2)]. This specification provides an estimate of the marginal change in electricity prices resulting from a marginal increase in total demand that depends on the technology that satisfies the increase in demand. For example, an increase in demand of 1 GWh that is fully satisfied with energy sources under the special regime is associated with an average decrease of almost 0.6 € in the price of electricity.

The model also allows us to compute the average effect on electricity prices that results from a switch between energy sources, given a fixed level of electricity demand. For instance, for a given level of demand, an increase of 1 GWh in the production of electricity using energy sources under the special regime that substitute fuel or gas is associated with an average decrease in electricity prices of 7.9 € ($\hat{\beta}_1 - \hat{\beta}_6$). This same exercise may be done for any other combination of energy sources.

Concerning the other estimated coefficients, changes in the use of fuel/gas are positively associated with changes in the price of electricity. It is also interesting to notice that the use of hydro plants to cover a marginal increase in demand is associated with a larger change in the price of electricity than the use of nuclear plants (again, due to the reason given before: hydro plants are used in peak hours, whereas nuclear is a base load technology).

4.1. Robustness checks

Results are qualitatively unchanged if we perform the same analysis using weekly instead of daily averages. The marginal effect of a 1 GWh increase in electricity production becomes -1.589 € and is also significant at 1% confidence level using Newey and West (1987) robust standard errors as in the previous models. As one could expect, this estimated coefficient is slightly lower than the one estimated using daily averages (that was equal to 1.876 €) since by computing weekly averages we are smoothing the effects. The results of the alternative Durbin's statistic suggest there is no autocorrelation in the residuals in any of the models estimated using weekly averages.

We also re-estimated Models (3) and (4) including additional control variables such as the price of gas and CO₂ allowances that could have an impact on electricity prices. Both variables have positive but not significant coefficients while the rest of the estimated coefficients remain unchanged. A possible explanation for the lack of influence of gas prices is that most combined cycle plants have long-term contracts for gas supply, therefore isolating them to a great extent from the variation in gas prices.

Finally, a possible concern with the specification that includes all the technologies (Model 4 in Table 4) is the existence of multicollinearity. We explored this issue by computing the variance inflation factors (VIF). While in Model (3) all the VIF are smaller than 2, in Model (4) the VIF calculated for *COMBCYCLE* and *dd_t* (that is, the indicator variable for Mondays) are close to 4. In any case, although some standard errors may be inflated in Model (4) as a result of this, most of the estimated effects are significant and in addition we do not observe shifts in the sign of the estimated

coefficients (from positive to negative or vice versa) when introducing changes in the specification.

Summing up, *ceteris paribus* our results prove that an increase in electricity generation under the special regime reduces electricity prices. More precisely, we find that the marginal effect of electricity generation under the special regime on electricity prices is between -2.09 and -1.65 €/MWh with a confidence level of 95%. The point estimate indicates that a 1 GWh increase in electricity production under the special regime is associated with an average decrease of 1.876 € in the price of electricity which represent a 3.7% of the average price between January 2005 and December 2009.

5. Discussion and concluding remarks

This paper contributes to a very relevant line of research in this field, the assessment of the impact of an increased renewable energy penetration on electricity prices. Although the theoretical and *ex-ante* empirical literature on the issue is growing, these questions have so far not been explored using *ex-post* data. To fill the gap, this article develops a full *ex-post* empirical analysis for Spain by looking at data on hourly use of technologies and electricity prices from January 2005 to December 2009. We believe that it is particularly interesting to perform this study in Spain, where an active system of public support to renewables and cogeneration has led to a considerable expansion of these energy sources and electricity pricing is at the centre of intense debate.

As a major finding, the paper reports that a marginal increase of 1 GWh of electricity production using renewable energy sources is associated with a reduction of around 1.9 € in electricity prices (around 4% of the average daily price between 2005 and 2009). Our results show a lower impact of renewables on prices than previous studies do (e.g. Sáenz de Miera et al, 2008; Jonsson et al, 2010). The model also allows us to compute the average effect on electricity prices resulting from a switch between any two energy sources, given a fixed level of electricity demand.

Another interesting fact is that the impact of renewables on prices decreases with time, in spite of the larger contribution of renewables to the Spanish system. This may be

explained by a separate but coincident element, the increase in the participation of gas-combined cycles in the system: the drastic reduction of coal and the increase in combined cycles has resulted in that gas power plants (all of which are very similar in terms of efficiency and costs) set the marginal price at the wholesale market most of the time, thus providing a quite flat supply curve. Therefore, as the contribution of natural gas rises, the increase in renewables is less likely to change the price level because it will just produce a substitution of gas by a similar gas.

Another explanation for the decreasing impact on prices might be related to the fact, already mentioned in the introduction, that the price reduction effect is temporary, since the reduction in prices will in turn result in lower investments and therefore higher prices in future periods. However, we do not find this explanation applicable to the Spanish case as the system is currently experiencing overcapacity due to several reasons, and indeed prices are lower than in past periods. Therefore, we have not yet been able to observe the rebound in electricity prices due to a short supply.

The third possible reason was also mentioned before: If firms have market power, they can push prices up to compensate for the impact of renewables. This hypothesis is harder to reject: big firms are still in the Spanish market, with a portfolio of gas combined cycles and hydro which would allow them to exercise this market power if so needed. The problem here is to devise a sensible indicator for market power in the electricity sector which would allow us to isolate this effect. As is well known, the usual indicators of market power (HHI, Lerner, etc.) do not provide realistic measures of market power in this sector, and therefore alternative measures should be used.

According to our results on electricity prices, consumers should expect an average payment reduction of around 470 m € per year, significantly lower than the current annual cost of support of renewables (see section 2). Interestingly those two magnitudes have followed the opposite trend: the cost of support has increased (mostly due to the introduction of solar PV) whereas the reduction in prices has decreased. Indeed, in 2005 these two figures were very similar while, as previously mentioned, they are currently very different. Therefore, the theoretical prediction that this price reduction might compensate the cost of support depends on the technologies promoted and on the system configuration and therefore does not always hold.

The conclusions of this piece of research also cast doubts on the sustainability of current electricity market structures with a large renewable base. The decreasing trend in electricity prices may be incompatible with the necessary remuneration of non-renewable sources and thus new approaches should be explored to address this issue.

In any case, we would like to emphasize that the conclusions of this study, which is a first approximation to the issue, should be taken with care. As mentioned before, we would need a longer observation period to assess long-term effects, and we would also need to introduce a measure of market power to test its impact on the effect analyzed. We are currently working on both improving the database by separating renewable from cogeneration and implementing two additional quantitative approaches designed to construct a counterfactual for the price of electricity in the absence of electricity production under the special regime, to corroborate the robustness of the reported results.

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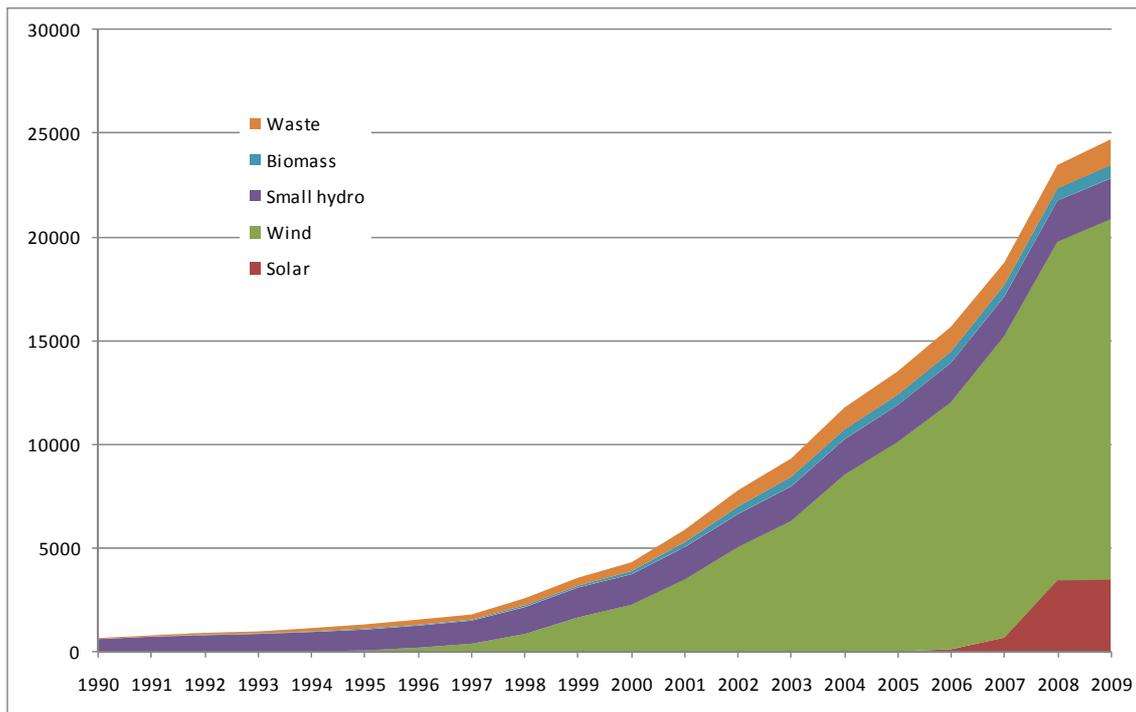
Wooldridge J., 2003. *Introductory Econometrics: A Modern Approach*. South-Western College Publishing, Cincinnati, OH.

Table 1. Premiums for renewables in Spain (€/MWh)

	<i>2004</i>	<i>2005</i>	<i>2006</i>	<i>2007</i>	<i>2008</i>	<i>2009</i>
<i>Solar</i>	332.52	340.40	374.06	392.14	388.74	429.33
<i>Wind</i>	28.08	28.92	37.37	36.35	35.97	42.75
<i>Small</i>						
<i>Hydro</i>	31.72	29.31	36.06	35.61	31.69	42.71
<i>Biomass</i>	30.54	27.87	35.17	46.71	52.06	73.10
<i>Waste</i>	22.65	20.29	33.18	37.48	35.84	61.10

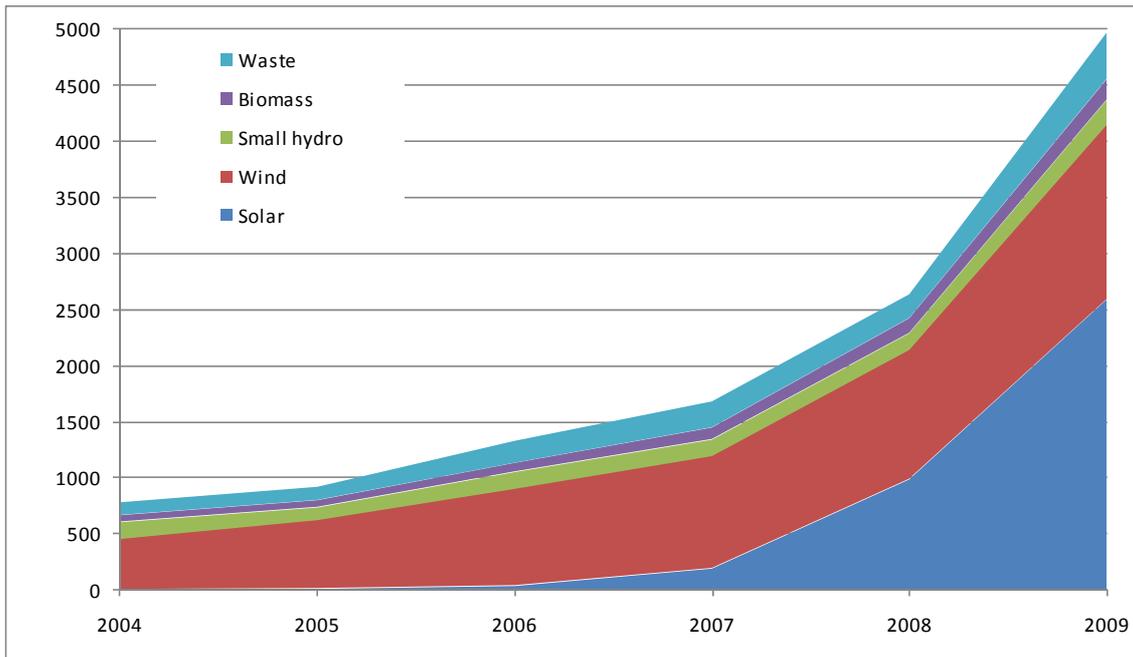
Source: CNE (2010)

Figure 1. Renewable installed capacity in Spain (MW)



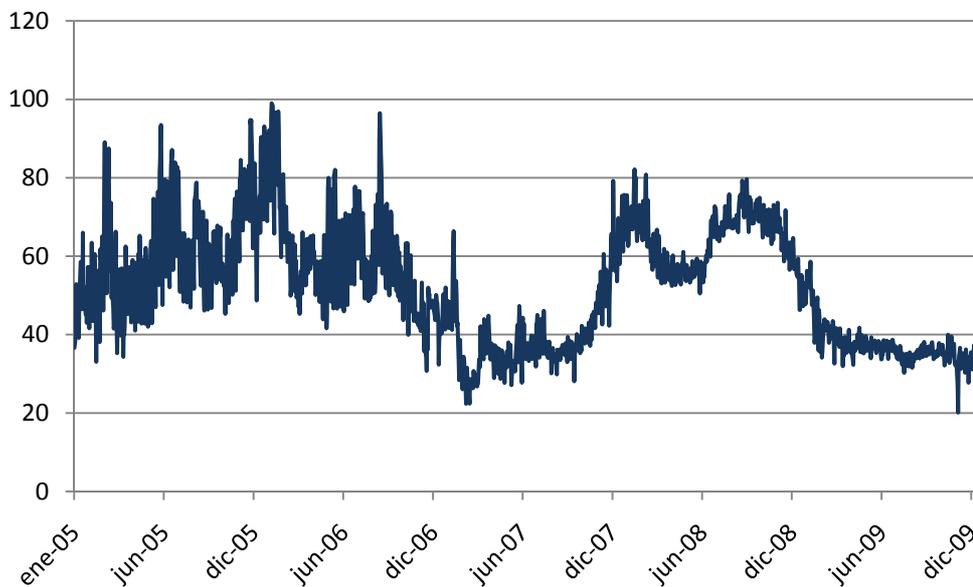
Source: CNE (2010)

Figure 2. Economic support for renewables in Spain (million €)



Source: CNE (2010)

Figure 3. Daily averages of final electricity prices (€/MWh)



Source: OMEL and CNE (2010)

Table 2
Descriptive Statistics

	2005 (N=365)		2006 (N=365)		2007 (N=365)		2008 (N=366)		2009 (N=365)		All Sample (N=1826)	
	Mean	St. Dev.	Mean	St. Dev.								
<i>ELECPRICE</i>	60.232	12.485	61.177	13.557	39.347	8.856	64.425	7.188	36.959	5.583	52.435	15.439
<i>TOTDEM</i>	28.245	3.454	28.426	3.416	29.907	3.324	30.036	3.233	28.882	3.079	29.100	3.383
<i>SPREGIME</i>	5.678 (19.56%)	1.253	5.225 (17.94%)	1.424	6.589 (22.00%)	1.542	7.563 (24.41%)	1.972	9.480 (32.10%)	2.176	6.907 (33.93%)	2.283
<i>HIDRO</i>	2.036 (6.97%)	0.687	2.845 (9.69%)	1.506	3.054 (10.20%)	1.127	2.326 (7.21%)	0.984	3.180 (10.77%)	1.132	1.713 (8.41%)	1.655
<i>NUCLEAR</i>	6.287 (21.68%)	1.011	6.570 (22.56%)	0.833	6.064 (20.24%)	0.993	6.493 (20.96%)	0.781	5.829 (19.74%)	0.864	3.681 (18.08%)	3.084
<i>COAL</i>	8.380 (28.80%)	4.811	7.085 (23.95%)	1.621	7.957 (26.13%)	1.130	4.953 (15.99%)	1.576	3.550 (12.02%)	1.416	3.296 (16.19%)	3.222
<i>COMBCYCL E</i>	5.498 (18.71%)	1.479	7.122 (23.94%)	2.001	6.177 (20.22%)	2.854	9.409 (30.37%)	2.831	7.231 (24.48%)	2.830	4.569 (22.44%)	4.448
<i>FUELGAS</i>	1.298 (4.28%)	0.848	0.593 (1.91%)	0.565	0.363 (1.21%)	0.114	0.326 (1.05%)	0.113	0.265 (0.90%)	0.037	0.191 (0.94%)	0.174
<i>OTHER</i>	-0.934	0.665	-1.014	0.625	-0.298	0.607	-1.036	0.468	-0.655	0.583	-0.787	0.655

All figures correspond to daily averages. Electricity prices are in € per MWh. Total demand and total generation by energy source are in GWh. Proportion of total generation corresponding to each energy source in parentheses. Total daily observations: 1,826.

Table 3
Correlations of daily changes

	$\Delta ELECPRICE$	$\Delta TOTDEM$	$\Delta SPREGIME$	$\Delta HIDRO$	$\Delta NUCLEAR$	$\Delta COAL$	$\Delta COMBCYCLE$	$\Delta FUELGAS$
$\Delta ELECPRICE$	1							
$\Delta TOTDEM$	0.585	1						
$\Delta SPREGIME$	-0.202	0.273	1					
$\Delta HIDRO$	0.589	0.712	0.026	1				
$\Delta NUCLEAR$	-0.048	0.061	-0.003	-0.014	1			
$\Delta COAL$	0.493	0.687	-0.117	0.461	0.018	1		
$\Delta COMBCYCLE$	0.13	0.836	-0.141	0.561	-0.012	0.587	1	
$\Delta FUELGAS$	0.596	0.425	0.059	0.429	-0.023	0.207	0.209*	1
$\Delta OTHER$	0.432	0.033	-0.339	0.134	-0.083	0.045	-0.041	0.287

The correlations reported in this table correspond to the variables in first differences.

Table 4
Augmented Dickey Fuller Test Statistics

<i>Variable</i>	ADF (in levels)	ADF (in first differences)
<i>ELECPRI</i>	-2.297	-6.354
<i>TOTDEM</i>	-4.499	-7.352
<i>SPREGIME</i>	-3.141	-9.020
<i>HIDRO</i>	-3.495	-7.207
<i>NUCLEAR</i>	-4.387	-7.154
<i>COAL</i>	-3.553	-6.704
<i>COMBCYCLE</i>	-2.975	-7.324
<i>FUELGAS</i>	-4.233	-7.284
<i>OTHER</i>	-3.463	-7.533

MacKinnon (1996) critical values for rejection of hypothesis of a unit root are -2.570 (for 10% confidence level), -2.860 (for 5% confidence level), and -3.430 (for 1% confidence level) for the models with constant and no trend and -3.120 (for 10% confidence level), -3.410 (for 5% confidence level), and -3.960 (for 1% confidence level). The reported statistics correspond to models that include a constant and 24 lags. We included a trend for *ELECPRI*, *SPREGIME*, *COAL* and *FUELGAS*.

Table 5
OLS estimation of daily changes in electricity prices

	Dependent variable: $\Delta ELECPRICE_t$			
	(1)	(2)	(3)	(4)
$\Delta TOTDEM_t$		1.259*** (0.117)	1.439*** (0.100)	
$\Delta SPREGIME_t$			-1.876*** (0.093)	-0.585*** (0.108)
$\Delta HIDRO_t$				2.329*** (0.677)
$\Delta NUCLEAR_t$				-0.314 (0.318)
$\Delta COAL_t$				1.310*** (0.199)
$\Delta COMBCYCLE_t$				0.560*** (0.104)
$\Delta FUEL GAS_t$				7.336*** (0.528)
$\Delta OTHER_t$				3.492*** (0.346)
WEEKLY DUMMIES	Yes	Yes	Yes	Yes
MONTHLY DUMMIES	Yes	Yes	Yes	Yes
ANNUAL DUMMIES	Yes	Yes	Yes	Yes
OBSERVATIONS	1826	1826	1826	1826
Adjusted R-SQUARED	30.51%	35.77%	50.23%	67.88%
Alternative Durbin p-value	60.258 0.000	62.921 0.000	78.137 0.000	153.048 0.000

All the models include an intercept; Standard errors in parenthesis are robust to heteroscedasticity and serial correlation (Newey and West, 1987); *** indicates $p < 0.001$. Alternative Durbin (p-value) reports the statistic and the p-value of the alternative Durbin's test for autocorrelation with H_0 : no autocorrelation.

Table 6
OLS estimation of daily changes in electricity prices
(First and last demand quartiles)

	Dependent variable: $\Delta ELECPRICE_t$	
	(1) (First quartile)	(3) (Last quartile)
$\Delta TOTDEM_t$	1.315*** (0.134)	1.423*** (0.225)
$\Delta SPREGIME_t$	-1.494*** (0.195)	-2.206*** (0.146)
WEEKLY DUMMIES	Yes	Yes
MONTHLY DUMMIES	Yes	Yes
ANNUAL DUMMIES	Yes	Yes
OBSERVATIONS	453	458
Adjusted R-SQUARED	48.88%	59.22%
Alternative Durbin p-value	7.066 0.000	10.592 0.000

All the models include an intercept; Standard errors in parenthesis are robust to heteroscedasticity and serial correlation (Newey and West, 1987); *** indicates $p < 0.001$. Alternative Durbin (p-value) reports the statistic and the p-value of the alternative Durbin's test for autocorrelation with H_0 : no autocorrelation.