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Assessing the cost of renewable energy policy options – A Spanish wind case study

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A R T I C L E I N F O

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A B S T R A C T

This paper assesses the cost effectiveness of wind energy policy options by using a cost–benefit analysis approach. In comparison with other studies, the main contribution of this paper is the use of real financial and operational information of 318 wind projects in Spain between 2006 and 2013. The projects represent 83% of total new wind capacity additions in Spain during the 2006–2013 period. Under real market conditions, it is found that the most cost effective option for promoting wind energy development from the government perspective is to use an investment credit policy given the capital intensive nature of wind technology. The analysis shows that an investment credit yields similar results as other policy options like feed-in tariffs and feed-in premiums, but at a cheaper cost and with less risk to the taxpayers or electricity consumers because costs do not fluctuate with electricity market prices.
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1. Introduction

The aim of this research is to provide a better understanding of the relationship between renewable technologies and the cheapest financing method from the perspective society (taxpayers or ratepayers), using real data from 318 Spanish onshore wind projects. We deliberately focus on the direct cost of the policy, while other potential indirect benefits or costs are not considered.

Countries around the world are promoting the adoption of renewable energy technologies as a means of enhancing energy security, environmental sustainability, national industries and green jobs among others [1]. However, currently some governments are reevaluating renewable energy's policy support [2]. This is the case for some European countries. For example, in Spain regulators implemented a feed-in tariff as the main form of subsidy, which succeeded in the significant deployment of renewable technologies [3]. However, concerns about policy costs grew as more wind was deployed and economies, such as Spain, slowed. Spain was emblematic of the tension between renewable energy deployment, costs, and the risk to ratepayers associated with market price volatility. In this context, the European Commission [4] suggests that, if public support is not carefully designed, it can distort the operation of the electricity markets and lead to higher costs for households and businesses. It is not only the capacity of renewables deployed that matters, but it is also the cost. Spain is an ideal case study, particularly with respect to wind energy, for looking at historic projects and assessing the cost of the policies. According to the BP Statistical Review of World Energy [5], as of 2013, Spain ranked fourth in wind installed capacity after China, USA and Germany. Although Spain's energy policy successfully deployed a large quantity of wind energy, it came at a cost which led to policy changes from 2006 to 2013. (see Appendix I for a detailed description of shifts in renewable energy policy along the timeframe). In this context, as Menanteau et al. [6] indicate, one of the problems in designing public interventions is the lack of granular cost information available for policymakers. Financial incentives to promote renewable technology can become too small or too large when there is a lack of accurate cost information.

In contrast to other studies, this study uses real wind project data, addressing granularity issues, to compare feed-in tariffs and other subsidy types, including feed-in premium or production tax credit, and investment credit in order to understand which option is most cost effective. The paper uses data from 318 onshore wind projects built in Spain from 2006 to 2013, totaling 10,732 MW. The use of real project data reveals valuable insights about the relationship between financial conditions and capacity factor that are

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normally omitted in theoretical approaches. These relationships are relevant since they have an impact on the cost of the projects and the cost of the policy. Although this paper does not focus on financial instruments for promoting renewable technology, it does not imply that financial conditions are not as important as public policies for the deployment of new technologies, as Masini and Menichetti [7] point out.

This study shows that investment credits are the most economical way of promoting renewable energy, but they lead to the lowest return on capital employed for private investors. On the contrary, feed-in tariffs provide a guaranteed revenue to investors but the total cost of the policy is the highest for the ratepayers. We want to highlight that this is not a study on Spanish renewable policy. This study uses information of Spanish onshore wind data to compare different policies in terms of support, cost and deployment of renewable energy in an accurate way.

In our opinion, this is a very relevant finding. Nowadays, feed-in tariffs are being abandoned in Europe in favor of new models of support. There is a growing consensus which supports that feed-in tariffs have been an expensive tool for promoting renewable energy, as for example Schmalensee points out [8].

The paper is structured as follows: Section 2 presents the scenario development and methodology. The results from the scenario development are represented in Section 3 and a discussion of the policies is present in Section 4. Section 5 concludes the paper.

2. Scenario development & methodology

This paper considers three subsidy types and a no-policy scenario: feed-in tariffs (FIT), production tax credits or feed-in premiums (FIP), and investment credits (IC). For the purpose of analysis, the production tax credits and feed-in premiums are treated equally since they are both an output subsidy on a euro per MWh basis.

2.1. Policy instruments

The FIT used in this analysis is a guaranteed minimum fixed price (in real terms) for the electricity produced over the life of the wind projects. If the market price is greater than the FIT, then the owner of the wind facility receives the market price. If the price of electricity is low, investors receive the FIT price. This type of policy generates an asymmetric, though appetizing, risk for investors [9] On the other hand, the burden for electricity ratepayers is variable and ultimately depends on dynamics of electricity market prices. This kind of FIT has been partially in effect in Spain during the period 2006–2013, but there are other possible designs for FIT. The National Renewable Energy Laboratory [10] provides a detailed description of alternative FITs. The FIP is a fixed amount that is added to the market price. This policy instrument was used in Spain to promote renewable technology, but in very limited scale. Finally, An IC is a percentage discount on the initial investment that is given to reduce the costs of a technology, i.e., a direct subsidy. For example, a 10% IC for a €1 million wind project would result in €900,000 in costs for the developer, while the government shoulders the remaining €100,000. An IC can also be applied on a fixed euro per MW basis as a lump sum. Intuitively, the fixed reduction IC not only makes projects cheaper but tends to reduce the financial incentive for lower cost projects relative to costlier projects that the percentage IC discount provides. This type of lump sum subsidy does not benefit expensive projects as all projects, regardless their investment cost, receive the same amount of financial support. Spain did not implement this policy instrument to promote renewable energy.

2.2. Data

A number of data sources were used. Bloomberg New Energy Finance (BNEF) is the primary source of information (leverage, capacity factor, location, CAPEX, and number of projects) regarding the wind projects characteristics [11]. Wholesale prices, from both the Iberian Market Operator [12] and the Comision Nacional de Los Mercados y La Competencia (the Spanish Regulatory Body) [13], were used to compare the costs of policies relative to the market. Additionally, the Spanish Regulatory Body reports information on electricity produced from wind and financial support given to wind. Interest rates regarding long-term bank loans come from the Bank of Spain [14].

The cost of equity was assumed as 8% as assumed by BNEF [15], and the government discount rate was assumed to be a constant 3.7% as suggested by Martin-Moreno [16]. Both costs are in real terms for the period of analysis in order to have a unified approach to compare values. The operating life of all projects is 20 years as it is the accepted timeframe for renewable projects.

The capacity factors of the wind projects are estimated based on project-level BNEF and Spanish Regulatory Body information. Regarding the financial conditions, we assume that all debt is structured as amortized loans in which there are equal payments over the maturity of the loan. All costs for projects in the analysis, which cover a period of 8 years, have been translated to constant Euros, with 2014 being the base year.

The dataset includes financial and operational information of 318 onshore wind projects implemented in Spain from 2006 to 2013. Projects included in the dataset have a minimum installed capacity of 15 megawatts (MW). The projects represent 10,732 MW of installed capacity, and 83% of the 12,885 MW installed during the 2006–2013 period, according to BP Statistical Review of World Energy 2014 [5]. In order to assess the cost of each project, we used the weighted average cost of capital (WACC) as the real discount rate. The WACC of each individual project is the weighted average between the cost of the equity, that we assume to be 8%, and the cost of debt, which changes depending on the year each project is commissioned. The average WACC of projects in the analysis is 6%.

Table 1 shows that the number of wind projects commissioned per year declined from 58 to 5 projects from 2006 to 2013. The amount of new capacity additions declined from 1896 MW–190 MW per year. This was due to the government's shift in support for wind which is indicated in the Appendix.

The wholesale electricity market in Spain is liberalized. The market price in Spain is set in a day-ahead market and it depends on the expected supply and demand along the day. In addition, there is a real-time market to sell and buy electricity during the day, allowing fine-tuning of prices and quantities as it is common in European markets.

2.3. Methodology

A cost–benefit analysis (CBA) was conducted to compare the total discounted revenue and the total discounted cost for each of the 318 projects during their economic life. The analysis takes the perspective of private investors, then calculates the incremental cost of policies to taxpayers and/or electricity customers.

The levelized cost of electricity (LCOE) is representative of the "cost" metric of the CBA. It illustrates the stream of equal payments normalized over expected energy production. The levelized avoided cost of electricity (LACE) represents the "revenues" metric in the CBA. It is the estimate of the revenues available to a given resource normalized over the expected energy production period. Calculations for both LCOE and LACE are adapted from Namovicz [17] and are the standard approach in the literature. The difference

Table 1
Summary of key data.

Year	Number of projects	Total installed (MW)	Investment (EUR thousand)	Debt-level	Capacity factor
2006	58	1896	€ 1263	50.8%	26.7%
2007	64	2145	€ 1311	43.5%	23.9%
2008	69	2166	€ 1353	49.0%	24.8%
2009	54	2004	€ 1452	42.0%	22.7%
2010	29	937	€ 1587	48.1%	25.7%
2011	26	986	€ 1365	46.7%	21.7%
2012	13	408	€ 1260	59.4%	23.2%
2013	5	190	€ 1230	45.6%	19.2%
Total	318	10,732			
		Average	€ 1361	47.1%	24.3%
		Minimum	€ 1214	10%	11%
		Maximum	€ 1600	85%	46%

Source: Author's calculations based on BNEF and Bank of Spain data.

between the LACE and LCOE is the net value, which depends on the incremental annual cost to the government (taxpayers) in order to breakeven. The incremental cost of each subsidy to the government was calculated assuming a government discount rate of 3.7%. Finally, we assume that investors are risk neutral. This assumption is, obviously, a simplification, but we do not have data on this variable.

In our methodological approach we are not paying attention to the relationship between deployment of renewable technology and price of electricity. The deployment of renewable energy tends to decrease the price of electricity and tends to increase its volatility as Browne et al. (2015) [18], Clò et al. (2015) [19], Würzburg et al. (2013) [20] and Paraschiv et al. (2014) [21] point out. We conduct a partial equilibrium analysis that compares the cost of policy, assuming that there is no change in the rest of the variables of the market. Assessing the impact of the deployment of renewables on prices and consumer's welfare requires a general equilibrium analysis and that is not within the scope this study.

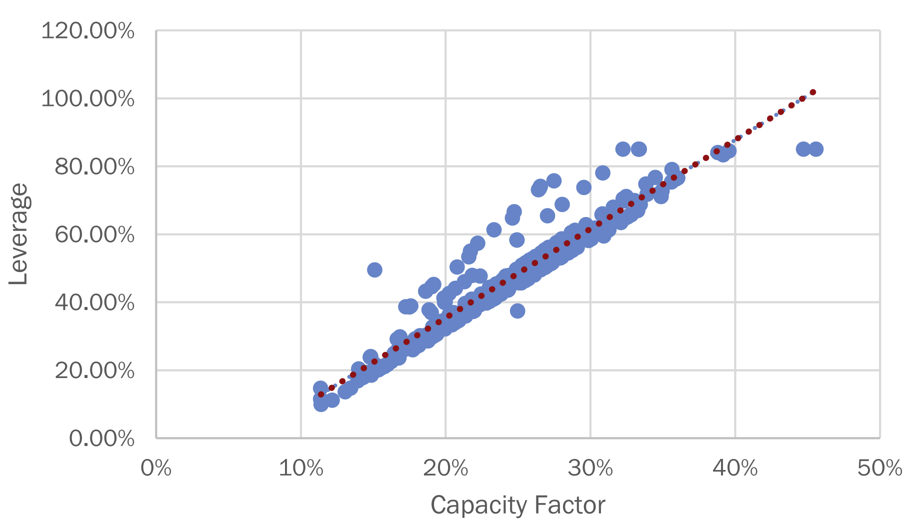
3. Results

3.1. Relationships & wind supply curve

Novel relationships for Spanish onshore wind projects were uncovered during analysis of the dataset. One of which is the relationship between the capacity factor and debt-level of projects. As indicated in Fig. 1, the financial structure of a project depends on the capacity factor, which is the utilization rate of a plant. There is a clear positive correlation between capacity factor and debt leverage, higher quality projects (those with higher capacity factors) are financed with higher levels of debt (high leverage). Whereas lower quality projects (those with lower capacity factors) have more equity financing (lower leverage). A possible explanation is that projects with lower capacity factor will receive less income along the life of the project, making these projects less attractive for bank financing. It is important to highlight that the cost of equity is higher than the cost of debt (see Table 1). As a result, higher capacity factor projects have lower WACC. This is a relevant finding, since the bulk of previous studies consider the WACC constant regardless the capacity factor. Wiser and Steven [22] realized that the private cost of production of electricity for these technologies are highly sensitive to financial conditions.

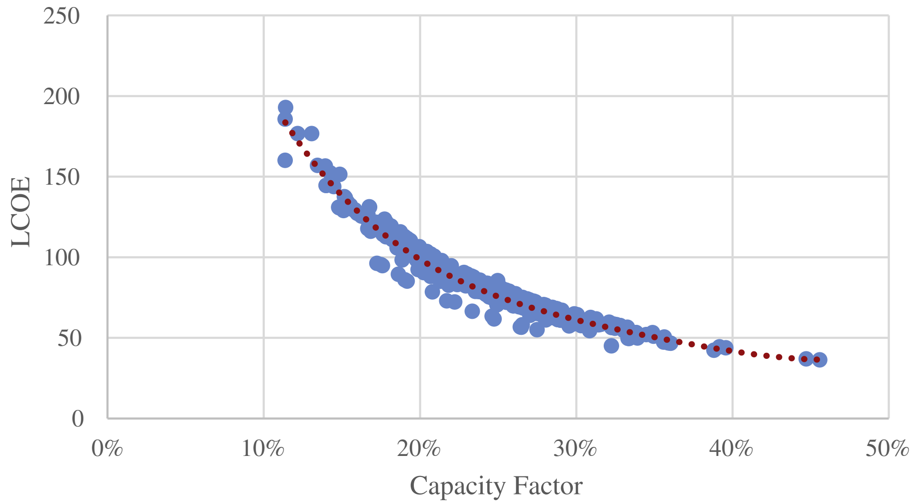
Capacity factor is a key determinant of a project's LCOE. Since the variable costs of wind energy projects are minor, the more a facility operates, the lower its per unit cost. Fig. 2 plots the LCOE and its relationship with the capacity factor of each project. Although analysts and decision makers typically use a single number when representing a technology's LCOE, according to actual data LCOE and capacity factor can vary substantially by project. The bulk of projects in our dataset have a capacity factor between 15%–29% and a LCOE between €59/MWh – €99/MWh.

Finally, using the LCOE for each wind project in the



Source: Author's calculations based on BNEF data.

Fig. 1. Capacity factor & leverage.



Source: Author's calculations based on BNEF data.

Fig. 2. Capacity factor & LCOE.

dataset allows us to construct a wind supply curve ranking the projects from least to most expensive. Fig. 3 presents the wind supply curve with each project's LCOE and the cumulative capacity (MW). Fig. 3 is not a conventional supply curve, since it does not link production of electricity and marginal costs of production. Rather, the curve represents the long-run cost of constructing and operating the various projects over their 20-year useful lives. The average LCOE for Spanish commissioned wind projects in our dataset is €84/MWh, while the median is €78/MWh. This supply curve for onshore wind commissioned projects in Spain is an original result and it is the cornerstone for the rest of this analysis.

In this section we used the data available to construct a curve that links LCOE and installed capacity deployed, in an innovative approach. This curve will allow us to evaluate the cost of different projects in future sections.

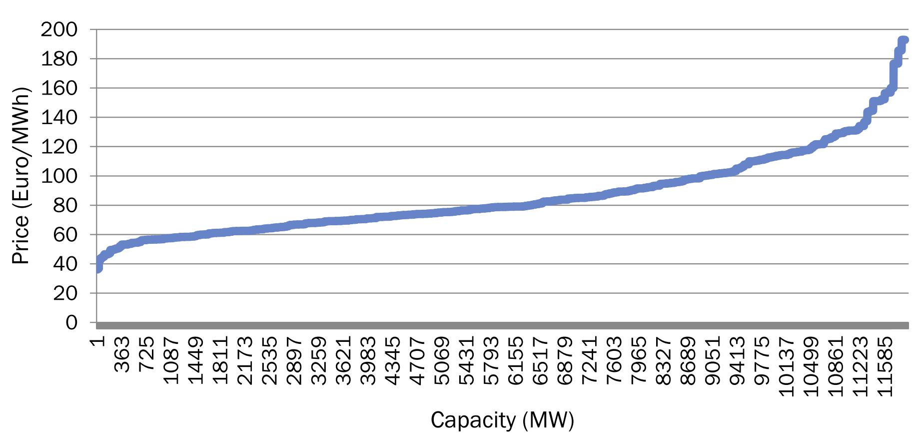
3.2. Scenario analysis

3.2.1. No policy support scenario

To begin examining the cost competitiveness of the wind projects, we evaluated their LCOE against potential revenues in a baseline "no-subsidy" market scenario. The real price of electricity in this scenario is a constant €48.6/MWh over the 20-year study period. Electricity prices are volatile from hour to hour, and daily average prices can fluctuate widely. Between 2006 and 2014, the real daily price of electricity ranged from a minimum of €0/MWh to over €106/MWh. The average daily price over this period was €48.6/MWh with a standard deviation of €15.3/MWh. Around 76% of the daily price observations are within the price interval €33.4/MWh – €63.9/MWh (average ± one standard deviation). This data is from the Iberian operator for electricity markets. The timeframe for prices (2006–2014) is different than for the database (2006–2013). However, it is not an inconsistent decision. All projects and cost of this study are evaluated at constant euros of 2014.

Using the baseline market scenario as a proxy for unit revenues allows for a clearer picture of the competitive situation of wind technology in Spain. If we compare the LCOE of the projects (project wind supply curve) with their potential levelized revenues, we find that only 200 MW of 10,732 MW have a positive net present value (NPV). In other words, only 1.9% of the total installed capacity is potentially economic under market conditions. As a result, the cumulative NPV of the projects in Spain is found to be negative €7.80 billion. The average NPV scaled per installed capacity is negative €0.73 million/MW.

Ultimately, the NPV of each individual project depends on the final price of electricity. As prices increase, the NPV of the projects improve. In particular, if the real price of electricity achieves €78/MWh, the cumulative NPV of the 318 projects would be zero.



Source: Author's calculations based on BNEF data.

Fig. 3. Wind supply curve.

However, this is a very unlikely scenario because only 3.7% of the prices observed in the period considered are greater than €78.

3.2.2. Feed-in tariff

This analysis uses a FIT level in real terms of €83/MWh. The FIT level was derived from the reports by the Spanish Regulatory Body for the period 2009–2014.

In the FIT scenario, 6120 MW of installed capacity are economic with a positive NPV. The cumulative NPV of the projects is €1.3 billion. These results are constant under a market price of €0/MWh - €83/MWh because the wind projects receive the same revenue from the FIT at those price levels. As electricity prices increase beyond €83/MWh, the NPV and amount of economic wind capacity increases.

On the contrary, the discounted cost of the policy is a mirror image the NPV for investors. The incremental cost of the policy is greatest if the market price is €0 and decreases as prices increase. The incremental cost of the policy is equal to €0 if the market price exceeds €83/MWh. In the baseline market scenario of €48.6/MWh, the incremental cost to ratepayers of the FIT is €11 billion (€1.0 million/MW).

Our analysis indicates that a FIT policy option yields risk on the government and ratepayers but is stable for investors because of the revenue certainty afforded by the policy in a vast majority of the scenarios, 98.1% of the prices observed were below €83/MWh.

The remainder of our policy scenarios use the 6120 MW of cumulative economic capacity from the FIT scenario as a benchmark to allow for equal comparisons of different policy subsidies. This capacity figure acts as the policy target. By setting the benchmark as cumulative capacity we can clearly understand the cost on the taxpayers and ratepayers and the revenue to the investor in achieving the desired MWs.

3.2.3. Feed-in premium (FIP)

Under a FIP we have selected €35/MWh as a baseline FIP subsidy amount. This is because a €35/MWh subsidy on top of a €48.6/MWh baseline market price yields equivalent results in terms of achieving the benchmark 6120 MW of economic projects.

Unlike FITs, a FIP policy option shifts the cost risks from the government/taxpayer to the investor. In this case, the cost of the policy to the taxpayer does not change, sitting at €11 billion (€1.0 million/MW), regardless of the price. On the other hand, revenue and thus NPV for investors fluctuates with prevailing market prices. The NPV of the projects increases with prices. Under this policy scheme, investors face potential upside and downside risk. This is why if investors are risk averse, a FIP is less attractive than a FIT. Dinica [23] points out that risk is as important as expected yield in order to support renewable technology.

A FIT of €83/MWh and a FIP of €35/MWh produce exactly the same results if the market price is €48.6/MWh. However, the uncertainties regarding the cost for policymakers and the benefits for investors are different under both policies. The FIP shifts risks toward investors and so an increase in their WACC can be expected. Higher volatility of income implies that investors will seek higher yields and lenders will require higher interest rates. However, there is no data to assess the impacts at the level of individual projects.

To examine what might be the impact of such an increase, we applied a uniform increase of 1% to the WACC. This increases the average LCOE of Spanish wind projects by €5/MW. Under the new conditions, the baseline subsidy required to achieve the target (6,120 MW) increases to €40/MWh, resulting in a 15% (€1.7 billion) increase in policy costs. In the worst case, increasing the WACC by 2% results in an additional 31% (€3.5 billion) cost for the policy.

3.2.4. Investment credit

An IC of 53% is required to achieve the benchmark 6120 MW of economic projects. The cost of this policy €8.4 billion (€0.80 million/MW). This means that, despite being a steep discount, an IC can achieve the same benchmark level of economic wind capacity at a cheaper cost than a FIT and FIP. This policy does not entail any additional risk from the policy side as the cost of the policy is known from the onset and is not affected by electricity market volatility.

Despite being cheaper than FIT and FIP, an IC can be a less attractive option for policymakers than FIT and FIP. The reason for that is the ICs method of payment, which is an upfront payment, is paid directly via public spending. In addition, ICs can be risky for investors because the amount of return is dictated by electricity prices and can fluctuate with these changes. Similar to the FIP, we conducted a sensitivity analysis increasing the WACC. A 1% increase, across the board results in a need for a higher credit (57 percent). Increasing the cost of the policy by 7% (€0.6 billion). An increase of 2% results in the cost of the policy increasing by 12% (€1 billion).

An IC results in a downward shift of the wind supply curve. However, this shift is not parallel. Instead there is a general flattening of the curve, because higher cost projects (in €/MW terms) and those with lower capacity factors, and thus higher WACC, experience greater LCOE reductions than cheaper projects with lower WACC. This scheme tends to provide a greater incentive for costlier projects, normally those with lower capacity factors. A way to correct for this unintended result, is by giving a fixed sum investment credit rather than a percent reduction. It was found that a lump sum of €792,000/MW of installed capacity generates the benchmark amount of cumulative capacity, 6120 MW. The fixed IC is a cheaper policy than a percent-reduction IC by €0.94 billion (an 11% reduction).

4. Discussion: comparison of policies

Average electricity market prices can vary in the future and, then, we conducted an analysis for prices between €0/MWh and €100/MWh. Four critical prices were selected in order to evaluate the cost of the policies. Table 2 reflects the discounted cost of the policies in the four market price scenarios. For a market price below €48/MWh the FIT is the most expensive policy. Between €48 – €56/MWh, the FIP is the most expensive subsidy for the government. The IC is cost effective for prices below €56/MWh. If the market price, in real terms, is consistently above €56/MW the FIT is the most economic subsidy. If the price is greater than €83/MWh, the cost of the FIT is zero.

A key element to understanding why an investment credit is cheaper than a feed-in tariff or a feed-in premium is to look at the discount rate of future payments. Society (taxpayer, ratepayers, or government) has a lower discount rate than private investors.

In general terms, the FIT is the most expensive policy given the Spanish market conditions. Schmalensee [8] suggests that, despite its popularity around the world, "[FIT] is almost certain not to minimize the cost of achieving program's goals" (see pg. 2 of document [8]). According to Schmalensee's analysis, a mandate, such as the Renewable Portfolio Standards in the U.S., is cheaper than a FIT under market conditions.

For policymakers an IC is the most appealing policy option, because it represents the minimum financial burden at which the policy targets are achieved at market conditions. Only if policymakers expect a market price that is systematically above €56/MWh, they would then prefer a FIT policy option. This scenario seems unlikely given the prices over the period 2006–2014 and the fact that wind tends to operate in off-peak periods.

Table 2
Cost of policies (EUR billion).

Price (€/MWh)	Percentile of scenario Price within 2006–2014 observation (%)[a]	Policy option		
		FIT (€83/MW)	FIP (€35/MW)	IC (53%)
0	99.9%	26.1	11.0	8.4
48	50.5%	11.0	11.0	8.4
56	25.8%	8.4	11.0	8.4
83	1.9%	0.0	11.0	8.4
100	0.2%	0.0	11.0	8.4

The sample covers 318 Spanish wind projects, representing 10,732 MW.
[a] Instances when observed 2006–2014 exceed reference prices in column 1.
Source: Author's calculations based on BNEF data.

However, despite the fact that the investment credit appears more attractive from a societal perspective, it has the disadvantage of having to be paid up front using public finances. It could be hard to implement from a political point of view. On the contrary, the FIT and FIP are paid normally by the electricity consumers over the life of the project, making them attractive for policymakers.

Table 3 depicts the NPV of the total projects for the different policy scenarios (including a "no-subsidy scenario) and market conditions from an investor's perspective. For investors, a FIT is the most appealing policy option for market prices below €48/MWh. For prices above €48/MWh, a FIP would be the preferred policy by investors.

Analysis conducted affirms that investors would prefer a FIT because of the constant positive return even in low market price scenarios. Investors that expect prices of electricity to be systematically over €48/MWh would prefer a FIP given the higher return on investment. In this analysis, IC would not be supported by investors under any price condition.

The analysis looks at policy options individually. It does not take into consideration a combination of policies. A case could be made that combining policy options yields more economic results for society or more financially attractive results for investors, as Mir-Artigues and del Río [24] suggest.

5. Conclusions

This paper analyzes the cost of different policy options for promoting wind energy using a dataset of 318 real Spanish onshore wind projects. The projects represent 10,732 MW of installed capacity, and 83% of total installed during the period 2006–2013. This study addresses the granularity issues that are omitted in a vast majority of renewable energy studies. The dataset reveals some interesting insights regarding the relationship between financial conditions and capacity factor that normally are omitted in theoretical approaches. In particular, projects with higher capacity factor tend to be financed more through debt than equity, and thus have lower average costs of capital.

Since renewable technologies are capital intensive [25], the most cost effective option for society to promote wind technology, without risking total costs fluctuating with electricity prices, is to use an investment credit policy (subsidy to investment). This is because an investment credit cuts the initial cost of developing a project. The policy yields the same results as other policy options including feed-in tariffs and feed-in premium or production tax credits, but at a cheaper cost in plausible electricity price scenarios. However and from the point of view of private investors, a feed-in tariff is the preferred policy option. Investors obtain higher profits under this policy and the volatility associated with market prices are minimized.

Despite the fact that the investment credit appears more attractive from a societal perspective, it has the disadvantage of having to be paid up front using public finances. On the contrary, the FIT and FIP are paid normally by the electricity consumers over the life of the project. This can explain why these policy instruments have been widely used in many countries.

To sum up, given market conditions in Spain the most cost effective policy option for policymakers comes in the form of an investment credit because of the capital structure of renewable technologies. However, private investors prefer feed-in tariff because they maximize the return on their investments.

Appendix. A review of renewable energy policy in Spain, 2006–2013

Spanish power generation from wind represented 20% of total electricity generation in 2013, ranking third in the world after Denmark (32%) and Portugal (22%). At the beginning of the economic crisis in 2008, financial support for wind amounted to €1.2 billion. By 2013, the level of support doubled to €2.4 billion according to the Spanish Regulatory Body. The increase in subsidies in a fragile economy led a change in the Spanish government's renewable energy outlook. A shift towards a less favorable legal framework was especially clear since 2010. As a result of this change in the regulatory environment, wind installed capacity almost stagnated in 2013.

Key regulatory policy changes in the period 2006–2013 include:

Table 3
Cumulative NPV (EUR billion).

Price (€/MWh)	Percentile of scenario price within 2006–2014 observation (%)[a]	Policy Option			Market "no subsidy"
		FIT (€83/MW)	FIP (€35/MW)	IC (53%)	
0	99.9%	1.3	−11.2	−11.9	−20.3
48	50.5%	1.3	1.3	0.6	−7.8
56	25.8%	1.3	3.4	2.7	−5.7
83	1.9%	1.3	10.4	9.8	1.3
100	0.2%	5.7	14.9	14.2	5.7

The sample covers 318 Spanish wind projects, representing 10,732 MW.
[a] Instances when observed 2006–2014 exceed reference prices in column 1.
Source: Author's calculations based on BNEF data.

- Royal Decree 661/2007. Superseded Royal Decree 436/2004. The new Decree established a system of feed-in tariff and feed-in premium, but with a lower level of public support than the previous Royal Decree 436/2004. (See Asociacion Empresarial Eolica – Association of Spanish Wind Companies – (2007) [26] and IEA/IRENA Joint Policies and Measures database [27]).
- Royal Decree 6/2009. Established that future renewable energy power projects must be pre-registered before they can be eligible to receive public support. (See Asociacion Empresarial Eolica (2010) [28] and IEA/IRENA Joint Policies and Measures database [27]).
- Royal Decree 1614/2010. A maximum financial support was established for wind generators, in particular electricity production. Wind generators that exceeded the limit were not entitled to financial support. (See Asociacion Empresarial Eolica (2011 and 2012) [29] [30] and IEA/IRENA Joint Policies and Measures database [27]).
- Royal Decree Law 1/2012. New renewable facilities that are developed do receive financial support. (See Asociacion Empresarial Eolica (2013) [31] and IEA/IRENA Joint Policies and Measures database [27]).
- Royal Decree Law 15/2012. Imposed a 7% tax on electricity generation, including renewables sources. (See Asociacion Empresarial Eolica (2013) [31] and IEA/IRENA Joint Policies and Measures database [27]).
- Royal Decree Law 2/2013. The removal of feed-in premium from the incentive options for wind power generators. This is a retroactive law as all facilities, either old or new, were impacted. (See Asociacion Empresarial Eolica. (2014) [32]).
- Royal Decree Law 9/2013. The feed-in tariff system is replaced by an investment incentive. This new incentive was designed to guarantee a return on investment similar to that of a 10-year sovereign Spanish bond plus 300 basis points. This is a retroactive law that affects all renewable energy plants. (See Asociacion Empresarial Eolica (2014) [32] and IEA/IRENA Joint Policies and Measures database).

The evolution of the regulation on wind energy explains the stagnation of Spanish wind projects in 2013. It seems that the economic recession changed the perception of the Spanish Government on renewable energy and currently it was less likely to favor wind projects.

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