VALUATION AND ANALYSIS OF THE EUROPEAN UNION RENEWABLE ENERGY SUPPORT MECHANISMS USING OPTION THEORY

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Abstract

We examine the economic efficiency of incentive mechanisms used to promote renewable energy (RE) as a policy in the European Union. We evaluate the financial performance of RE investments and employ real option theory to model and analyze their impact in liberalized markets for electricity. Our analysis concerns key European countries and uses five years of most recent historic electricity price data from 2009 to consider sensitivities around key parameters. As RE policies are presented as public goods to address environmental concerns, we explain how the financial performance of these policies strikes a balance between social costs and private benefits. We discuss the impact which RE may have upon market conditions under liberalized markets for electricity generation and whether incentive mechanisms should be re-calibrated in light of these results. For other regions, our research offers useful lessons on both the effectiveness and cost-efficiency in the design of schemes to incentivize RE.

Keywords: Feed-in tariffs, Feed-in premiums, Real-Option Theory, Investor Returns

1 INTRODUCTION

In many regions of the world reducing the usage of fossil fuels through supporting the use of wind turbines, solar cells and other technologies is one of the most prominent objectives of energy policy, alongside security of supply, reliability of delivery and affordability. Meanwhile, concerns have been raised about the affordability of RE from the standpoint of consumers, business and industry. Given the presumption that such policy cannot be achieved without incentives and government support, at the heart of the affordability debate of renewable electricity generation is the question of support mechanisms and, therefore, it is important to understand how such support mechanisms should be designed and how extensive they should be. Using standard financial and economic theory, we evaluate the widely used RE support mechanisms as adopted by the largest economies of the European Union (EU), excluding the United Kingdom, and address their economic efficiency as manifested in the returns to investors in RE and social costs, including externalities. We take both the market value of incentives paid to investors and their total value to analyze the financial performance of RE under the various support mechanisms found across a number of EU countries and observe whether or not the returns provided were commensurate with the risks. Further, to examine the social optimality of such investments, we employ option theory to measure the indirect costs of RE comparing them with the private benefits earned by investors. We use representative plants, costs, localized operating characteristics, such as solar irradiance and historic country level electricity price data from 2009 to 2013. We also consider how changes to key parameters may impact the value of support for RE. The fact that Germany, Italy and Spain have recently revised their support schemes, lends weight to the growing perception that many schemes had design or calibration problems [1, 2, 3].

The paper is organized as follows: in section 2 we provide perspectives on the topic of RE support mechanisms and then turn to the efficiency of support mechanisms as covered in the public finance and environmental economics literature. Section 3 explains how we use financial option theory to model the exposure created through dispatch priority, as afforded to renewable generation, to address the issues raised in the literature review on the economic efficiency of RE incentive mechanisms social costs included. In section 4 we present measurements of the financial performance of

RE generation, both in terms of private benefits and social costs in order to observe the calibration of incentive support mechanisms in liberalized, traded markets for electricity. The concluding section relates our findings to some of the broader concerns and critiques of the EU energy and environmental policies.

2 RE AS PUBLIC GOOD

According to public finance theory, the nature and size of public goods need to be decided through collective or social decision making rather than through market processes [4]. RE is supported as a public good to correct the externalities associated with fossil fuels such as GHG, especially when effective taxation of CO_2 has proved difficult. To maximize social benefits and reduce social costs, various incentive mechanisms have been put forward to encourage investment in RE, particularly in wind turbine or photo voltaic electricity generation. But how may one quantify the social benefits of reducing GHG and determine by how much RE should be supported? Formally, the decision on how much of a public good should be produced requires finding the level of production which maximizes the difference between marginal social benefits and marginal social costs [5]. Given the global nature of GHG and atmospheric warming, it is difficult to apply this rule to decide how much RE is required. But with governments having set targets for RE investment and de-carbonization, such as the latest 2015 UN targets, we can ask how large incentives should be to achieve such objectives and ensure allocative efficiency, i.e. aligning private benefits with social costs. The literature on these issues exposes several research frameworks and opinions.

2.1 Support Mechanisms and Instruments for RE: A Literature Review

The premise of policy making in the design of effective support mechanisms for RE is that, although the short-run marginal cost of such generation is negligible, the fixed costs are very high compared to fossil fuel electricity generation and, therefore, RE would not be developed without incentives. The alternative of putting a price on CO_2 and changing the merit order of dispatchable electricity generation has been attempted but, arguably, for many reasons has been unsuccessful [6]. In designing incentives for the liberalized markets of Europe and North America there are special challenges as one must rely upon markets to deliver renewable generation on public good grounds but the consensus varies on what works best [7].

In traded electricity markets support mechanisms usually involve removing or modifying the various risks faced by renewable investors through combinations of guaranteed prices above a floating price, a fixed premium or uplift to a floating electricity price, and a transfer of risks to other parties or the greater system [8]. Indirect support may also be derived through the possibility of revenue from trading RE certificates [9]. What works best in delivering RE investment continues to be debated, although according to US Department of Energy National RE Laboratory [10], tariffs are more compatible with deregulated generation markets. In summary, there has been varied research into the effectiveness of policies in promoting renewable targets but a consensus has not emerged. Given the levels of renewable investment now achieved in Europe, North America and elsewhere, the focus of debate has shifted to the costs and efficiency of delivery mechanisms as explained below.

2.2 Allocative Efficiency and RE

The premise that deregulated and privatized markets for electricity require sufficient incentives to attract investors begs the issue of how to ensure economic efficiency in delivering policy goals. To achieve economic efficiency, various approaches have been used to calibrate the above mentioned schemes, including calibrating incentives (i) using the levelized cost of RE (LCOE); (ii) according to the avoided utility generation cost; (iii) based on the value of RE to society; (iv) using RE project costs plus a reasonable return; and (v) using an auction to calibrate the right to supply RE to promote price discovery and avoid economic rent [11].

Calibrated in different manners and often revised, the shear variety of such methods suggests a lack of consensus on how to deliver supply while avoiding economic rents, how to align social costs with private benefits and ensure economic efficiency. For example, a study of wind parks in Portugal, found that owners of such RE were over-compensated under the feed-in tariff scheme. The Portuguese

Authorities used a LCOE model to determine what they thought would be the necessary and appropriate level of support. The researcher showed that under the 2005 legislation $4.1bn was spent on feed-in tariff supports and, moreover, the 2013 legislation required another $840million of public spending upon wind energy supports [12]. In Ontario Canada, a debate over whether a support scheme for wind and solar RE should be cost or revenue-based was resolved by adopting the German approach to benchmark incentives for local wind and solar RE [13]. In numerous countries a surge in renewable investment has been followed by actions to reduce incentives, suggesting a divergence between how policy makers value subsidies such as feed-in tariffs or premiums, and how the markets and investors may see them [14, 15].

To calibrate a support mechanism to ensure its economic efficiency, we need to compare the direct cost of the incentive price against the market price, as well as any indirect costs given the nature of RE and the market setting. The intermittency of RE and the lack of dispatchability need to be considered in the valuation of renewables because electricity is not storable thus its price varies depending on when it is produced. In deregulated, liberalized markets, electricity is usually priced hourly or half-hourly. The common method of comparing renewables with fossil fuels generation uses LCOE and treats electricity as a homogenous good and power supply from different fuels and technologies as commoditized perfect substitutes. This is problematic, however, because it ignores temporal and spatial issues and their consequent system impact [16, 17].

To tackle the system costs created by RE, the US Department of Energy recently proposed a new metric: Levelized Avoided Cost of Energy (or, LACE) to measure the economic merits of renewables including the cost to the grid or system to generate the electricity that is otherwise displaced by a new generation project. This approach is being evaluated now but has not yet gained acceptance [18]. Yet, using LACE requires system level knowledge and may involve arbitrary decisions over what is the marginal plant. Altogether we see a lack of lack of consensus on how we should calibrate incentives for RE in liberalized markets to determine appropriate compensation and, ultimately, promote economic efficiency. To address the issues around valuation of incentives, we introduce a new way of looking at RE according to how its costs may be hedged to analyse the appropriate level of returns given the risks and impacts. This affords a better understanding of the financial performance of RE in a liberalised market settings, of how incentives should be calibrated to reward RE investments efficiently.

3. METHODS, MODEL AND DATA

The first step towards proposing appropriate calibration for RE incentives is to know the value derived from operating RE in an integrated, liberalised traded market for electricity. This would require answering a number of questions. For example, from an investor in RE perspective, empirically, what returns were earned under the various incentive schemes offered in the EUs liberalized, traded electricity markets? Secondly, from the perspective of economic efficiency, incorporating the full impact of RE in liberalized markets, has the return provided to investors been generous? Thirdly, do such returns to RE investors embody all direct and indirect costs from the operation of renewable generation? And, lastly, as the priority dispatch of renewable electricity into an integrated liberalised system may make markets more volatile and reduce prices, how could be the impact in terms of system cost, exposure and economic efficiency appraised? These aspects are discussed below.

3.1 RE in Liberalized Markets

Setting the right incentives for RE in liberalized, traded markets for electricity presents many challenges. In the 1990s most programs to deregulate and liberalize electricity markets gave a prominent role to trading. Through the interaction of supply and demand, markets were balanced and reliability ensured, with the marginal price set by the most efficient plants, the CCGTs. In such markets, fossil fuel generators compete on short-run marginal costs in order to sell to a centralised grid which owns the high-voltage transmission systems and sub-stations. In liberalised electricity markets wholesale prices for electricity are made half-hourly, reflecting the requirements of the largest users who are metered 48 times per day. Through system planning and the right mix of flexible and less flexible plants, the grid operators may use short-term balancing and trading markets to cover demand prediction errors or unplanned outages, while entering into longer-term contracts to avoid supply disruptions and ensure adequate reserve margins.

Introducing RE into the above market structure and dynamics presents challenges as it cannot be dispatched on demand but generates when the wind blows or the sun shines. For this reason, renewables are given “dispatch priority”: when they are generating, other plants with flexible and controllable output must reduce their output. Dispatch priority creates short-term balancing costs for the grid and incumbents, plus long-term costs such as the need for grid connections and investment in more dispatchable generation as back-up. The average thermal efficiency of incumbent plants may be reduced and the frequency of unexpected outages and break-downs may grow. Such externalities need to be incorporated when we measure the value of RE. Setting incentive mechanisms for renewables (such as feed-in tariffs or feed-in premiums) while excluding the benefits (of not paying for the common resource of dispatchable back-up generation and grid management) mean the true returns and benefits to RE are under-estimated and, ultimately, resources wasted.

3.2 The Value of Renewable Energy

As discussed above, operators of RE plant receive an incentive price for what they generate but comparing the value of their revenues against the costs of investments does not tell full story. Rather, the private return to investors should be compared with the total costs of RE schemes, including not just incentive prices but any indirect costs of created exposures. To value RE properly in a liberalized market setting, we employ option theory as has been applied to model and optimize flexible, dispatchable plants [19, 20, and 21]. The RE purchase obligation across the EU upon grid operators, supply companies and consumers means that, whenever the sun shines or the wind blows, output must be reduced and all other dispatchable plant must be re-prioritized or even shut-down. Typically, a renewable operator will enter into a long-term supply contract with a renewable aggregator or integrated utility resembling a contract for differences between the market price and the price paid through the feed-in tariff or premium. The difference between the value stream to the renewable operator from a feed-in tariff or a feed-in premium and the normal wholesale price of electricity faced by the purchaser of RE, creates an exposure for the buyer and ultimately society. Under most schemes if hourly prices exceed the tariff the renewable operator must return the excess [22]. Through applying option theory we may quantify the value of this exposure.

In agreeing to take renewable electricity in which the buyer is liable for the difference between the market and incentive price, effectively a contract for differences, an exposure is created and ultimately imposed upon the greater system. This exposure theoretically could be hedged by purchasing a strip of put options (the right to sell) with strike prices equal to the feed-in tariff price. The theoretical price of the option represents the cost for accepting such risk by the purchaser, and ultimately borne by the system. If market prices fall, the exposure arising from a contract for differences grows, but through using put options conferring the right to sell at the incentive price, a purchaser of RE could theoretically hedge the exposure because the price of the put option embodies this volatility. The price of the put option represents the cost for having to take RE under the purchase obligation ultimately borne by society’s stakeholders, as it is equal and opposite in value to neutralize the exposure.

To price the exposure from the difference between market price and that of RE, through for example a feed-in tariff, we use put options with strike prices set at the price paid for such energy, as could be used to neutralize and off-set the cost of purchasing electricity above the market price. In summary, the combination of dispatch priority and incentive pricing enjoyed by renewable operators creates an exposure for the buyer and, ultimately, for the system or grid which may be priced and theoretically hedged using put options. Other approaches have been considered to quantify the exposure to RE, such as comparing it with the LCOE, but as already explained this excludes any indirect costs of RE. One researcher has tried a statistical approach to value the contract for differences (CfD) against futures markets but lack of liquidity and risk aversion may render such results tentative [23].

3.3 Data

Turning to data requirements, for the years 2009 through 2013, data were collected for the following: (i) support levels for RE for the majors countries of the EU; (ii) wholesale prices for electricity across within these countries; (iii) price volatility in the same countries; (iv) daily sun irradiation by countries; (v) average capacity factors for wind turbines and photo-voltaic facilities and (vi) costs per installed MW of renewable investments. Data from the Council of European Energy Regulators (CEER) was used for support levels by country and technology, per MWh as summarized in Table 1 below.

Table 1. RE incentives

RE Incentives for Belgium, France, Germany, Italy, Netherlands, and Spain (Euros MWh)	2009 - 2013	SOLAR PV	SOLAR OTHER	WIND OFFSHORE	WIND ONSHORE
	Minimum	€ 220.53	€ 68.04	€ 41.05	€ 41.05
	Maximum	€ 496.03	€ 290.90	€ 135.50	€ 224.80
	Average	€ 381.34	€ 177.34	€ 102.23	€ 92.60

Comparing what was paid for RE versus the wholesale market price of electricity, data was taken at day-ahead frequency for these same countries of the EU from Bloomberg. Several sources were checked for sun irradiation [24]. Data from the International Energy Agency (IEA) and the US Department of Energy, Energy Information Agency (US DOE) were consulted for capacity factors of both wind and photo-voltaic electricity generation [25 and 26]. Both official, EIA and IEA and commercial sources were examined for the price per installed unit of wind and solar capacity, with the World Energy Outlook for 2014 proving the most useful [27]. To adjust the time-value of the cash flows arising from renewable generation a weighted average cost of capital of 10% was assumed as it reflects the average opportunity cost of capital among Europe's major integrated energy utilities (while the return on investment averaged at 8%). Given the nature of the cash flow arising from renewable electricity generation, a discussion of whether a different rate should be used follows below. To calibrate the option pricing model, day-ahead price volatilities were taken from Bloomberg. Since historic wholesale electricity price data at half-hourly frequency is not readily available, a scalar adjustment was made to the option model calculations, based upon differences in value between day-ahead and half-hourly options to estimate the exposure which buyers of RE faced. Option strike prices were set at the various incentive prices as shown above. Incentive prices minus the historic market prices together determine by how much the option has intrinsic value. The option pricing software DerivaGem, Version 3.00 was employed.

4 MODEL SET UP AND RESULTS

We begin by examining the returns earned by investors in RE using a return on capital employed measure, specifically:

$$ROCE\ (\%) = \frac{Earnings\ before\ Interest\ and\ Tax}{Capital\ Employed} \qquad (1)$$

Capital Employed is the capital required to purchase renewable generation capacity and excludes funding liabilities. As operating costs of renewable plant are low for wind turbines, especially during the first ten years of operation, and even lower for photo-voltaic (estimated at just 1%), such costs were excluded from earnings. ROCE shows the value of a business and whether it can create value exceeding its WACC. (To validate the ROCE results, we also extended the 2009 to 2013 results to 2029, twenty years, and computed an Internal Rate of Return comparing the initial investment against the historic and projected revenues. Assuming a twenty year life span for the investments, the IRR results resemble the ROCE results.)

To analyse the value in RE, we compute a ROCE using the total amount received for generated output by an owner/operator. Sellers of RE receive a combination of the wholesale market price for electricity, plus the incentive premium paid by buyer, while buyers of RE are exposed at half-hourly granularity to the difference between the incentive price and the wholesale market price of electricity. We have averaged the result over the five years of available data and then compared it to capital employed. Summary results appear in table 2.

Table 2. ROCE

RETURN ON CAPITAL EMPLOYED				
RE Incentives for Belgium, France, Germany, Italy, Netherlands, and Spain (Euros MWh)	SOLAR PV	SOLAR THERMAL	WIND OFF-SHORE	WIND ON-SHORE
Minimum	17%	1%	6%	3%
Maximum	50%	36%	16%	68%
Average	32%	18%	10%	25%

Our calculations show that returns to RE owners and operators were very generous. Solar photo-voltaic technology earned the highest return on capital employed followed by on-shore wind energy. The average ROCE for solar photo-voltaic exceeds 30%, while for on-shore wind generation the ROCE was also very high. In Italy, for example, the returns to solar and wind were spectacular. Across the EU only Spain made noteworthy investment in solar thermal technology and the ROCE results exceeded 30%. Compared to the rate of 10% to discount the time value of future earnings, ROCE results greatly exceeded the assumed cost of capital. Given the guaranteed off-take, dispatch priority afforded to RE investors, the credit quality of counter-parties taking the generated electricity and the government backing to incentive prices, the generous terms provided to investors are surprising. As the relationship between incentive prices and ROCE is linear, cutting incentives in half would still have generated returns equal to, or exceeding, the WACC in all countries analysed. In summary, although the various programs across the EU were *effective* in getting RE plant built, the cost of incentives were economically inefficient offering supra-normal returns for essentially risk-free investments.

We now turn to measuring the exposure created by the operation of RE and faced by its, grid operators, integrated utilities and ultimately society. Buyers of RE, aggregators and integrated utilities under dispatch priority face the exposure arising from having to purchase electricity at the difference between the RE incentive price and the traded wholesale price of electricity. To hedge such an exposure, buyers of RE could purchase a strip of half-hourly put options to neutralize what might be lost from having to purchase electricity above the wholesale traded market price. Even if such options were not tradable, the price of the option represents the cost for accepting the risk. At day-ahead frequency, using the scalar adjustment noted in section 3.3 for five years, the prices of put options were computed using the standard put option model and parameters [28].

To appreciate the profitability for RE shown above, we quantify the externality per MWh of capacity from the operation of RE and compare it to what was earned per MWh of installed capacity. As in table 3 below, it would cost the buyers of RE on average nearly twice as much to hedge the exposure arising from the difference between the feed-in incentive prices to what the RE owner/operator received. For example, while the renewable operator with solar PV earned €342,100 per MW of capacity, it costs buyers of such RE €669,598 to hedge the exposure. Or for on-shore wind, the cost of the externality is the difference between €228,082 and €441,827.

Table 3. Revenues versus Hedging Costs

AVERAGE ANNUAL REVENUE OVER FIVE YEAR PER MW OF CAPACITY VERSUS COST OF HEDGING THE CONSEQUENT EXPOSURE				
COUNTRY	SOLAR PV	SOLAR THERMAL	WIND OFF-SHORE	WIND ON-SHORE
BELGIUM				
RE Owner/Operator Revenue	€ 256,891		€ 236,124	€ 229,284
Cost to Buyer to Hedge Exposure	€ 558,305		€ 494,240	€ 431,982
FRANCE				
RE Owner/Operator Revenue	€ 363,390		€ 311,525	€ 174,308
Cost to Buyer to Hedge Exposure	€ 788,972		€ 632,533	€ 348,868
GERMANY				
RE Owner/Operator Revenue	€ 250,184		€ 217,322	€ 99,099
Cost to Buyer to Hedge Exposure	€ 532,015		€ 451,584	€ 232,130
ITALY				
RE Owner/Operator Revenue	€ 503,184			€ 476,839
Cost to Buyer to Hedge Exposure	€ 858,351			€ 946,254
SPAIN				
RE Owner/Operator Revenue	€ 483,132	€ 359,723	€ 223,374	€ 223,374
Cost to Buyer to Hedge Exposure	€ 839,326	€ 617,290	€ 444,620	€ 375,802
THE NETHERLANDS				
RE Owner/Operator Revenue	€ 195,819	€ 42,147	€ 223,345	€ 165,587
Cost to Buyer to Hedge Exposure	€ 440,620	€ 86,489	€ 446,541	€ 315,923
AVERAGE				
RE Owner/Operator Revenue	€ 342,100	€ 200,935	€ 242,338	€ 228,082
Cost to Buyer to Hedge Exposure	€ 669,598	€ 351,889	€ 493,904	€ 441,827
AVERAGE DIFFERENCE	70%	63%	71%	67%

As shown in table 3, the costs of hedging one's exposure greatly exceed the gains from renewable operation. The result is intuitive: intermittency must be hedged for every half of the year while renewable operation is for only a small proportion, driven by the vagaries of the weather. The costs of hedging solar PV generation are greater in the Southern countries of Europe than those in the North due to the many more hours over which exposure is created. Although buyers of RE are only exposed to purchasing energy from solar facilities during day-light hours the higher incentives provided for the former makes the cost of hedging its exposure generally greater. The costs of hedging against exposures to renewables enhances the favourable returns enjoyed by RE generators. The RE operator imposes externalities, as measured through imposing hedging costs upon the greater market, enhancing his return significantly. If roughly one-half the portion of the costs imposed upon dispatchable generators and ultimately the society in hedging RE exposure were shifted to RE owner/operators their respective returns would be eliminated. Given the attractive returns provided to RE owner/operators and the externalities imposed upon buyers of their output, there would seem to be a strong empirical case for reducing the incentives provided.

5 CONCLUSIONS

In this work we have made two sets of observations based upon empirical research and analysis. The first concerns the financial performance from operating or owning a RE facility; while the second draws attention to the significant externalities arising from RE. Recalling the four questions above, we calculated the financial performance of various renewable technologies across the key countries of the European Union using a ROCE approach. We have found that the ROCE results, as incentivized for the various RE technologies under the various EU schemes, were high. At a time when Europe's major energy utilities were earning less than their cost of capital, investors in RE earned spectacular returns while taking little if any risk. Using option theory to quantify the exposure created for buyers of RE we have found that there were significant costs of nearly double what was earned from the operation of wind and solar facilities. Using the costs to society of having to hedge against the risk profile of RE rather than the already expensive incentive costs as measured in returns to RE investors, the full costs would be much greater.

It has been suggested that the presence of renewables may lower prices and contribute to price volatility, because prices and volumes are generally correlated [29]. Further, RE may create system wide costs as more thermal plants are paid to be on standby or minimum stable generation, lest the wind stops blowing or clouds appear. From option theory, we can see that if electricity market were to become more volatile, this would make the cost of hedging such exposure greater. Further, with variable cost of operating RE practically zero, the operation of RE may depress electricity prices by increasing the spread between the feed-in premium or tariff and the market price; increasing the cost of hedging against such an exposure. Not only does RE impose costs upon incumbents, the system and ultimately society but, through growing in output, it becomes more profitable. In summary, although the European Union has been successful in getting RE built, the direct costs of incentivizing RE plus the indirect costs to society, have been expensive and difficult to justify from the perspective of economic efficiency.

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