مركز الملك عبدالله للدراسات والبحوث البترولية
King Abdullah Petroleum Studies and Research Center

Renewable Energy: Lessons from the European Union Experience

Lawrence Haar

May 2016/ KS-1636-DP030A

About KAPSARC

The King Abdullah Petroleum Studies and Research Center (KAPSARC) is a non-profit global institution dedicated to independent research into energy economics, policy, technology, and the environment across all types of energy. KAPSARC's mandate is to advance the understanding of energy challenges and opportunities facing the world today and tomorrow, through unbiased, independent, and high-caliber research for the benefit of society. KAPSARC is located in Riyadh, Saudi Arabia.

Legal Notice

Key Points

Reducing reliance on fossil fuels in the generation of electricity through supporting wind turbines, solar cells and other renewable technologies has been a key objective of the European Union (EU) for more than a decade. Between 2004 and 2013, the largest 19 European countries more than doubled their renewable output but concerns have been raised about its affordability. In seeking to promote renewable energy, EU countries faced the following challenges from which some lessons can be learned:

Renewable energy costs are spread over fewer operating hours than conventional generation and, as such, expenditure per unit of output remains high, making financial support in the form of subsidies necessary in liberalized power markets.

Designing an economically efficient form of financial support for renewable energy proved elusive, resulting in exceptionally generous returns to investors.

In implementing incentive schemes across the EU, the large indirect costs imposed on dispatchable generators, who were forced to reduce capacity and accommodate electricity from wind turbines and solar PV, was not considered. Only recently have regulators considered paying for spare capacity or alternative market designs.

The piecemeal promotion and support given to renewable energy at country and even locality level, encouraged sub-optimal investment patterns and technical inefficiency while the complexity and opacity of these programs raised costs and contributed to abuse.

Executive Summary

Although the costs of generating electricity using renewable infrastructure have been falling, the costs per unit remains higher than that of conventional generation because expenditure is spread over a smaller output. Under the current structure of competitive power markets, renewable energy may continue to require incentives in the form of subsidies because its low operating hours and intermittency mean it would not earn a sufficient return at market prices. No method of setting incentives for renewable energy, including cost-based, value-based or even market-based approaches like auctions, can guarantee cost-efficiency. The uncertain availability of renewable energy imposes costs upon grid operators and dispatchable generators, which are hard to allocate properly under the liberalized model of electricity markets.

The EU's historic policy of promoting renewable energy through incentives has proved effective in delivering capacity and output, but arguably was inefficient from a cost perspective and provided overgenerous returns to investors. Subsidies and incentives had not been calibrated to decide what was/is a 'just-sufficient' rate of return to attract investment. Further, the complexity and opacity in the design of renewable energy support schemes raised costs, promoted inefficiency and may have enabled abuse.

In addition to the direct costs of subsidizing renewable energy, its intermittency imposed indirect costs on dispatchable generators as they were forced to reduce capacity to accommodate electricity from wind turbines and solar photovoltaic (PV) power. The impact of idle capacity and capacity run as backup to renewables called into question the viability of the current structure of liberalized traded markets in electricity and led to fresh calls for reform of ancillary services, capacity and availability payments. The experience of the EU in incentivizing renewable energy suggests the need to redesign markets to improve both short-term performance and ensure the adequacy of long-term investment.

The EU experience in promoting renewable energy also revealed the shortcomings of pursuing national targets. Europe has promoted an integration of energy markets to rationalize capacity and ensure supply flows to price, but the piecemeal design of renewable incentives at country level has led to inefficiency and suboptimal investment patterns compared to what might have been achieved under EU-wide incentives. Clearly, there is an opportunity to learn from the experience of the EU to design new policies which balance the needs for economic efficiency with the desired levels of renewables penetration.

Allocating the Costs of Renewable Energy

Reducing the use of fossil fuels through renewable energy or renewables such as wind turbines, solar cells and other power generation technologies has become a key objective of energy policy. However, it raises questions as to how to share the additional system costs. In competitive markets for electricity, as found in Europe, North America and elsewhere, on a levelized cost of electricity (LCOE) basis renewable energy generation does not yet compete with incumbent methods of producing electricity. While the price of renewable energy, particularly PV, has fallen to be competitive at the level of the cost of capacity, renewables typically have lower capacity utilization than conventional generation.

Compared with conventional methods of generating electricity, renewable energy is more capital intensive, but it has lower operating and maintenance costs and no fuel costs. As we see in Table 1, while the installed capital costs per unit of capacity of combined cycle gas turbine (CCGT) generation is below that of most renewable energy, apart from some onshore wind, the capital costs per MW unit of capacity of a representative coal-fired station exceed that of solar power and even offshore wind. But unlike conventional fossil fuel generation, the cost of renewable capacity is spread over a much smaller output, resulting in a greater LCOE (capital and operating costs ÷ output). For a CCGT plant, even cutting utilization of capacity by

Table 1. Cost comparisons renewable versus conventional electricity generation.

Cost Comparisons Estimates: Renewable vs. Conventional Electricity Generation (Coal Prices = €2.50 per MMBtu, Natural Gas = €5.00 per MMBtu)

Technology	Utility Scale Solar	Roof-Top Solar	Onshore Wind Turbine	Offshore Wind Turbine	Combined Cycle Gas Turbine (Heat Rate=6895)	Coal Fired Turbine (Dual Unit IGCC,Heat Rate=8,700)
Overnight Capacity Costs ($/MW)	€3,500,000	€3,750,000	€200,000	€6,000,000	€900,000	€2,700,00
Assumed Annual Capacity Factor	25%	25%	30%	35%	85%	85%
Levelized Cost per MWh (including system cost)	€115.00	€125.00	€71.00	€178.00	€68.00	€100.00

Source: Combined DOE-EIA and Fraunhofer Institute data.

one-half to 40 percent would only increase the cost of electricity from 5.2 cents per KWh to 7.2 cents per KWh. However, the commonly adopted solution – financial support mechanisms for renewable energy – creates costs for some combination of investors, taxpayers and rate-paying customers.

These technical characteristics challenge the operating model of liberalized traded markets for electricity. System stability and cost minimization requires controllable output to be bid through a competitive tender to the national or regional grid operator. However, renewable energy, driven by the weather and sun irradiation, cannot control when it will generate. Unstable supply or load intermittency forces incumbent fossil fuel generators in liberalized markets to accommodate renewable energy through adjusting their own capacity, reducing their revenues – and consequently creating additional costs. Depending upon the technical characteristics of their plants, their ability to adjust capacity may vary.

The output from CCGTs can be managed, but doing so reduces efficiency. By contrast, the output from coal and nuclear plants is less easily varied. But, adjusting all such plants to accommodate the output from renewables reduces efficiency and reliability. For system operators it means additional balancing costs, as dispatchable fossil fuel plants are kept on standby, at minimum stable generation, in case wind velocity drops or cloud cover appears. In addition, as the marginal cost of generating renewable energy is nearly zero, it depresses prices, reducing the earnings of fossil fuel and nuclear generators. Renewable energy can thus both create technical challenges and impose costs upon existing systems.

If an electricity supply system could be designed de novo under a different business model, renewable energy might be included in a less costly manner. Through incentives, promoting renewable energy has been effective, but the pressures on the incumbents operating under the prevailing business model are substantial. Almost half of generating capacity in Germany is now renewable energy and one-third in Italy and Spain. In many European countries, the renewables capacity exceeds peak demand. Arguably, incentivized renewable energy may undermine the functioning of liberalized deregulated markets, in which utilities produce power strictly according to the marginal cost of electricity and ensure system stability. Overall, established systems and utilities operating under liberalized competitive models for electricity may struggle to cope with renewable energy.

Recognizing such challenges but keen to follow a decarbonization agenda, many governments support renewable energy as a public good to correct the externalities commonly associated with fossil fuels such as greenhouse gases (GHG), especially as demand management through the taxation of CO2 has proved difficult. But supporting renewable energy raises questions:

- How much support is required?
- What means of support works best?

- Should support schemes be prescriptive in terms of technology, location or other factors?
- What level of support will maximize social benefits and reduce social costs?
- Given the global nature of GHG and atmospheric warming, should such development be encouraged everywhere?
- What forms of support will be effective in delivering renewable energy yet avoid waste and promote efficiency?

Accordingly, we examine here the key issues around support for renewable energy, including design and implementation issues, effectiveness versus efficiency, direct and indirect costs and potential policy options.

Alternative Support Schemes

The premise of policymaking in the design of support mechanisms for renewable energy is that, although the short-run marginal cost of such generation is negligible, the fixed costs are high compared with fossil fuel power plants. This perception, however, is not entirely accurate. Electricity generation from coal and natural gas can have high fixed costs too. As shown in Table 1, a key characteristic of renewable energy is that, by its nature, capacity is underutilized. No matter how it is incentivized, its costs need to be spread over few hours. But without incentives renewable energy might not be developed, so what approaches are available and what works best?

As summarized in Figure 1, for traded electricity markets there are four types of support mechanisms. Schemes may involve combinations of guaranteed prices above a floating price, a fixed premium or uplift to a floating electricity price, or other forms of subsidies. In one way or another, support schemes involve modifying the risk/reward profiles faced by renewable investors, operators, incumbent utilities and consumers. Fixed tariffs and premiums place a financial burden upon incumbent utilities and system operators. Quota obligations placed on fossil fuel generators resemble a tax on non-green electricity generation and move money from utilities and consumers to renewable energy

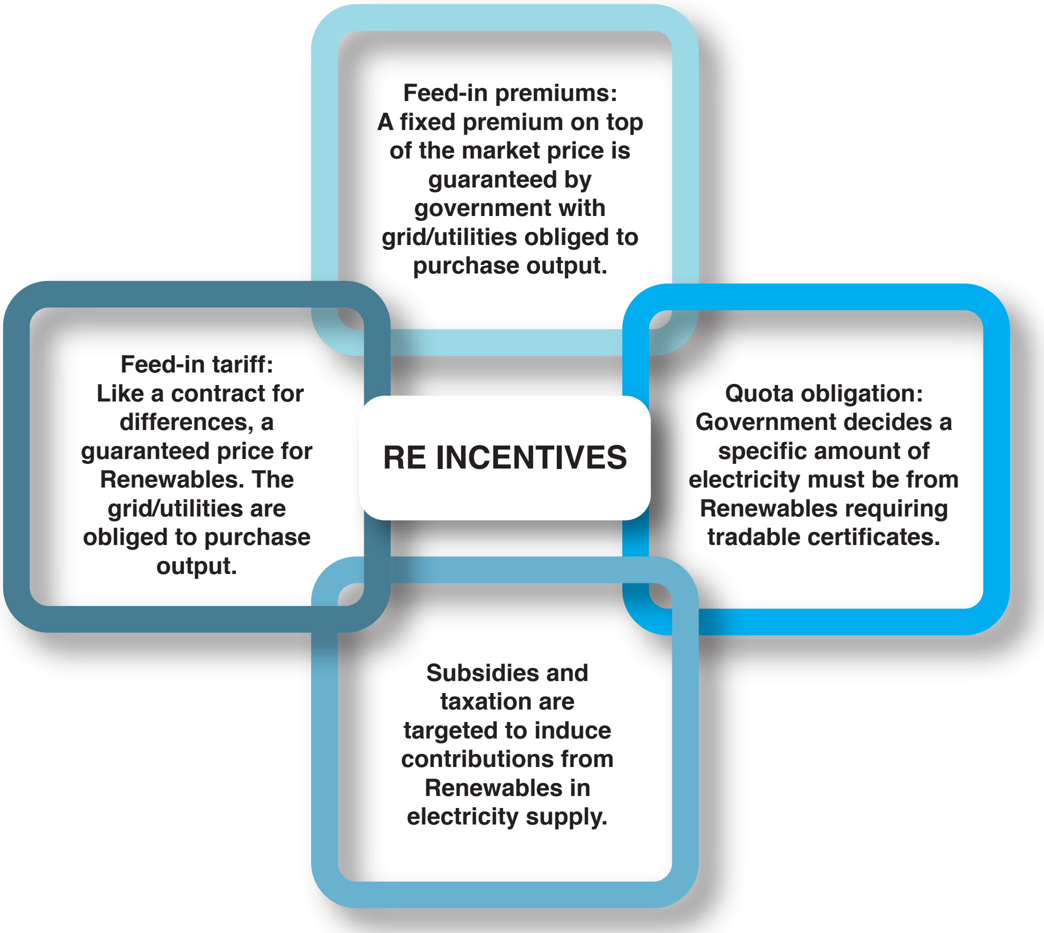

Figure 1. Alternative support mechanisms.

owners and developers. Upfront subsidies and tax credits may encourage development but don't necessarily ensure renewable energy output, putting risks upon regulators.

Discussion of the relative merits of support schemes for renewable energy hinge upon three sets of issues:

- What schemes work best in delivering output?
- Whether there may be unintended consequences.
- How support schemes are best funded.

In weighing what support schemes might work best in delivering output, policymakers have used diverse criteria. In the EU and North America, feed-in tariffs (FITs), feed-in premiums (FIPs) and quota obligations have been popular on the grounds that only actual output is paid for, putting construction risk upon developers. In other areas, minimizing financial risk to attract many investors and capital has been viewed as paramount, making tax and investment credits appealing.

Decisions as to prescribing the type of renewable energy generation, incentivizing specific solutions or allowing market forces to direct capital have also shaped the choice of support schemes. In France, tariffs and premiums for renewable energy were tailored to specific locations, sizes, technologies and uses. In selecting schemes, policymakers have also weighed capping the size and quantity of projects. Funding and supporting mega projects may just be too risky. While the merits of various renewable energy support schemes continues to be debated, in the view of the U.S. Department of Energy National Renewable Energy Laboratory (Couture, et al. 2010), tariffs are compatible with deregulated generation markets. Alternative schemes also have been supported on the grounds of interest in securing employment and promoting local benefits or content. Many arguments have been mustered to support renewable energy and how it may be incentivized, given its technical characteristics and costs. But in appraising the merits of what schemes work best, issues are raised with respect to both unintended consequences and how projects may be efficiently funded.

What are the consequences of supporting renewable energy? Providing long-term FITs may provide insufficient incentive to reduce upfront costs associated with renewable energy or improve the technology through time. With feed-in tariffs there are concerns that they may not be market oriented, put upward pressure on wholesale electricity prices and disadvantage industry and exports. In Germany, for example, when incentives designed for local manufacture of photovoltaic cells were found to be encouraging Chinese imports, the incentive scheme was changed. On the other hand, renewable energy quota obligations requiring integrated utilities to purchase a proportion of green energy or purchase certificates largely fall on consumers, reducing spending power. Providing tax or investment credits reduces fiscal revenues and these costs are ultimately borne by society.

Alternative Support Schemes

One party's subsidy or incentive implies another's tax or cost. Paying for feed-in tariffs or premiums places a burden upon electricity consumers and utility shareholders and aggregators required to purchase unpredictable renewable energy output. In Europe and North America, getting renewable energy built has been the main focus of policymakers; it is only as consumers began witnessing escalating electricity prices that discussions around its true costs have arisen. In the EU, the debate over the burden of renewable energy has been frustrated by the quality of disclosure about its actual support costs, often with only aggregate data being made available. As an exception, the disclosure of expenditures under the U.K. scheme was the most transparent of all EU countries. Deciding how best to pay for incentive schemes ideally requires knowing just how much is necessary to promote investment, including direct and indirect costs. Addressing what is received for the price paid has only recently become a subject of research.

Calibrating Support Schemes

Whatever support scheme has been chosen, setting or calibrating the required level of support needed to deliver investment has been problematic. The required level of support may be calculated according to such factors as the scale and technology, fuel and location. However, how much support is sufficient to promote renewable energy development without being unduly generous is a difficult question. In several countries, notably Spain and Italy, generous renewable energy support schemes combined with high quality solar resources and weak oversight, prompted a rush to development. Different approaches have been tried to calibrate the appropriate payment levels, such as adjusting to changes in generation costs over time, although this requires adequate disclosure and monitoring. Changing incentive prices according to capacity milestones has also been considered but may not favor cost-reduction. There is no consensus on how any risks associated with renewable energy should be rewarded. Policymakers have tended to focus upon the expected net present value of investments, but investors may look at returns on a risk adjusted basis.

Typically, renewable energy owners and operators will enter into offtake or power purchase agreements (PPA) with incumbent integrated utilities acting as aggregators. Such arrangements involve taking renewable energy power at fixed price incentives, feed-in tariffs or feed-in premiums and feature dispatch priority. Such incentive prices may greatly exceed prevailing market prices and, from an investor's perspective, apart from operational concerns, feature no market risk. A feed-in tariff, like a contract for difference (CfD), is a virtual annuity to renewable energy investors, with few risks.

Meanwhile, incumbent utilities are required to pay an incentive price that exceeds a floating market price, in addition to facing the risks of managing a fluctuating load and output from renewable energy generation. An incentive price might be sufficient to attract renewable energy investors but, given the twofold burdens on incumbent utilities and aggregators, if not mandated they would have no incentive to accept such arrangements – and renewable energy projects would not be built.

For incumbent utilities there are real costs to fluctuating delivery and output. The ability to mitigate the costs of fluctuating output, including the operational and reliability impact, may vary by firm. Depending upon their fleet of generating plants, capacity, flexibility, their customers and other factors, accepting and handling the commercial risks associated with renewable energy might be manageable. For other utilities, for example those heavily reliant on coal generation or even nuclear, a bilateral agreement with renewable energy owner/operators might be challenging, involving risks that could not be managed easily or commercially priced.

Consequently, the incentive prices offered to renewable energy investors might be sufficiently profitable – but are the costs and risks faced by integrated utilities appreciated? Should such costs be recognized in the design of incentives? Setting individual incentive prices including the cost structure of the incumbent utility as a counterparty might be impractical. While modifying the dispatch priority given to wind or solar generation, removing the guaranteed offtake, might render such investments unfinanceable.

Support Schemes and Liberalized, Traded Markets

In terms of how best to set incentives, there are three different approaches for renewable energy: cost-based, value-based or determined using market forces. Each has merits and limitations. Beginning with a cost-based approach, LCOE has long been used in the utility industry to set returns on a cost-plus basis: it involves a percentage markup to a product's unit costs, as computed in equation (1) below. Using LCOE for setting a return based on the unit costs of a renewable energy project may appear attractive, but it ignores the risks and temporal aspect of electricity markets as they relate to renewable energy.

$$(1)\ \mathrm{LCOE} = \frac{\text{Cost of renewable generating capacity}}{\text{Quantity of renewable output}}$$

In liberalized traded markets for power, electricity may be priced as often as 48 times per day (half-hourly). Electricity cannot normally be stored at utility scale and therefore it is important at what time electricity is generated. Further, location on the grid also matters: renewable energy generation tends to be in the remote locations that favor wind and solar generation. Being able to create half-hourly shape according to the needs of customers also has value. But renewable energy operators cannot determine when they will generate. Renewable energy spilled into the grid from a remote location at 4 a.m. may be worthless, while at 4 p.m. on a cold winter afternoon it will probably be highly valuable. Renewable energy creates system costs for incumbents to ensure stability, with output from their own dispatchable plant being reduced and kept running at minimum stable generation, like a motor vehicle left idling, waiting to be used. The LCOE formula does not incorporate the system costs of renewable energy and ignores the impact upon incumbent generators, so it has its limitations for calibrating renewable power incentives.

As an alternative to the cost-plus approach to setting incentive prices, some countries have promoted a value-based approach to setting incentive tariffs, known as the levelized avoided cost of energy (LACE). Taking this approach, the value of renewable energy to society or to a centralized utility or grid operator is used and is measured in terms of the savings made by displacing fossil fuels. As a metric to calibrate renewable energy tariffs and incentives, this approach has been promoted by the U.S. Department of Energy and has been used in Portugal. Depending upon how it is applied, it may incorporate an element measuring at what time and from where renewable energy is fed into the grid. Avoided cost may provide a proxy measure for the annual economic value, or savings of a candidate project, as summed over its financial life, and it is generally converted to a stream of equal annual payments.

Calibrating renewable energy incentives in this manner incorporates any saving to the grid from not generating electricity using conventional incumbent plants but may not incorporate the impact upon individual utilities of reducing capacity. Such savings, computed using LACE, might then be compared with the LCOE value to set renewable energy project incentives. Although intuitive, applying LACE requires system knowledge and the determination of what is the marginal plant. Further, it assumes an operating regime which can vary widely with market conditions. In sum, LACE is good in theory but hard to apply.

The final approach to calibrating and setting incentive mechanisms relies upon market forces to drive down the costs of renewable energy. To eschew the possibility of over-rewarding renewable energy producers and to protect energy consumers, some countries are now switching to competitive tender in awarding the incentives prices for feed-in tariffs (FIT). Under such a scheme, the lowest cost provider of renewable energy capacity would win the right to supply power into the grid. Rather than cost-based or revenue-based approaches, market forces are used to establish FIT prices through auctioning the right to dispatch power into established markets. The right to supply is then used to set the incentive prices available for renewable energy. This approach has been introduced in Spain for photovoltaic energy, in China for wind-generated electricity and India for various technologies. In several U.S. states it has been proposed as an alternative to administratively setting incentive prices.

Using an auction to calibrate the right to supply renewable energy to promote price discovery and avoid economic rent has merits but is not without problems. For example, it cannot be assumed that all projects having a positive net present value (NPV) will be of sufficient interest to bidders. Perhaps a risk premium may be required to solicit interest, but how large should it be? As has been shown in other settings, competitive tenders may lead to bids that in fact yield negative NPV to participants. What is known as the winner's curse, the situation where the highest bidder wins the right to supply renewable energy but has to do so at a financially non-viable price, may – in time – lead to renegotiation or even force majeure situations. Calibrating incentives using competitive tender does not address the impact upon incumbent generators and may still impose large costs upon incumbent fossil fuel generators and the greater system.

In summary, none of the popular methods for calibrating support schemes can guarantee that renewable energy will be delivered in a cost-efficient manner. Instead we propose adopting the metrics used by investors might provide a better picture of how renewable energy could be rewarded.

Complexity and Scope

Lessons can also be drawn from how EU support schemes were designed. In addition to the challenges of calibrating incentives correctly throughout the EU, complexity was added through tailoring support at national and even local levels. Unlike the U.K., where the scheme was applied nationally, with only size and technology determining incentives, across all the remaining 27 EU countries the range of renewable power incentives was, in addition, adjusted to at least six further parameters:

- Size of installation.
- Output from installation.
- Location.
- Own versus grid usage.
- Siting of installation (e.g., school, business or factory; ground or not ground mounted).
- Age of building upon which installed.

It is difficult to see what value this additional complexity delivered. Although the EU has tried to promote a single market for gas and power through alignment of grid codes and the building of interconnectors, for pan-European investors the different incentives have meant weighing the merits of 28 different locations. In addition, design complexity did not necessarily promote economic efficiency. For example, in France, photovoltaic facilities of equal size are eligible for different tariffs depending upon the age of the building where they are installed and how it is used. Provincial locations receive different incentive prices than metropolitan locations. Further, the price for renewable generated electricity varies according to whether it is being consumed or exported to the grid. In Belgium, like France, the incentive price for onshore wind also depends upon the location(Walloon versus Federal). Only in Germany and the Netherlands were the incentive premiums for onshore wind ratcheted downward with the level of output because the fixed costs could now be spread over greater MWhs.

Elsewhere, incentive prices were simply a function of capacity rather than output. Discouraging economies of scale, in many countries small, less efficient facilities received enhanced feed-in prices to presumably equate returns with more efficient, larger facilities. In the U.K., wind turbines between 100 KW and 500 KW enjoyed feed-in tariffs double those of facilities between 500 KW and 1.5 MW and four times that of facilities exceeding 1.5 MW. In Italy, too, economies of scale were discouraged as incentive prices favored smaller, less efficient facilities. Spanish feed-in tariffs also varied with scale.

Whether these myriad incentive alternatives – set at different national levels – contributed to capacity being built and economic efficiency promoted is unclear. Competition for renewable energy investment followed the most generous incentives as potential developers were encouraged to favor one location or one country over another. This failed to drive costs downward through competition between potential suppliers.

As shown in Figures 2 and 3, for both solar and wind generation the effective price paid per MWh was large. With national energy regulators encouraging developers to invest through incentive prices, cost-consciousness may not have been a priority. At EU level, it appears such questions as whether solar energy should receive the same incentives in Belgium as Italy or Spain were not asked. In 2010, all three countries offered around 300 euros per MWh.

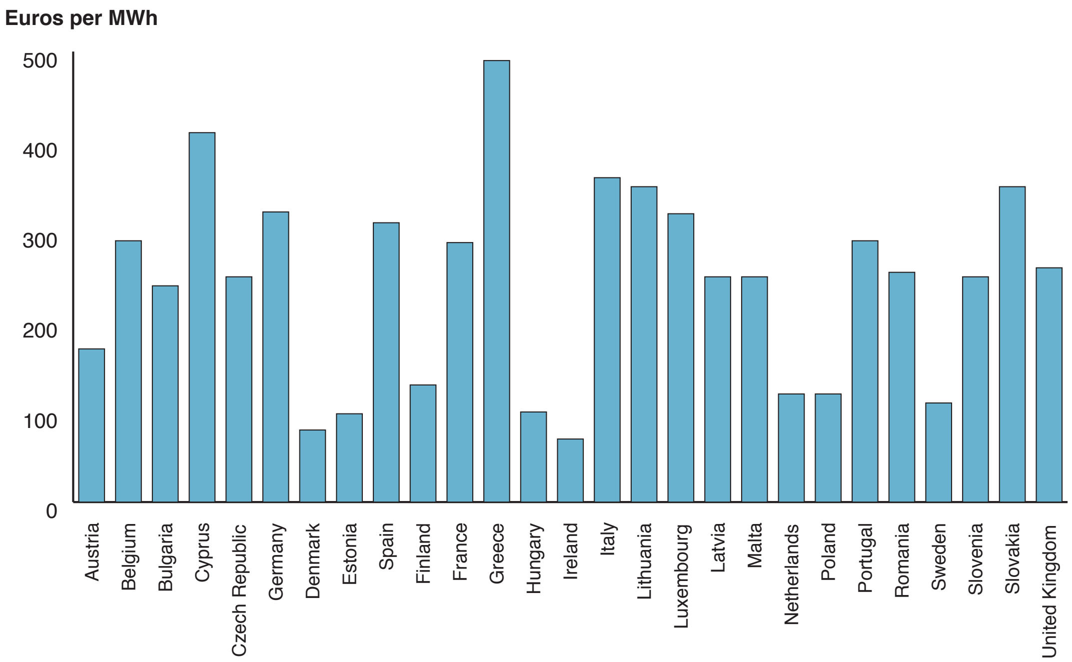

Figure 2. Solar expenditure per unit of output.

Source: Center for European Energy Regulators.

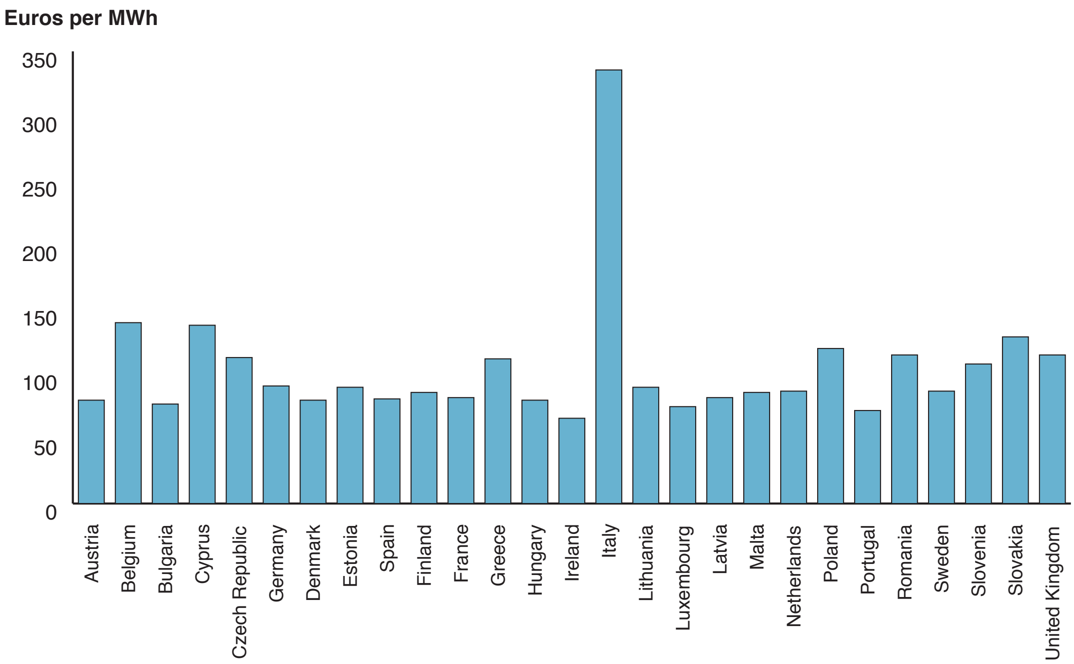

Figure 3. Onshore wind expenditure per unit of output.

Source: Center for European Energy Regulators.

Meanwhile Greece, known for its sunshine, offered the greatest incentives for PV support at 500 euros per MWh. In 2010 Italy, despite extensive coastline and mountains suitable for locating onshore wind, offered some of the most attractive incentive prices for renewable energy.

The range of incentives provided, as shown in Table 2, was large. Arguably, with each country vying for its share of renewable energy investment, perverse economic incentives and higher costs were encouraged.

Clearly, if the system had been designed top-down at EU level, economic common sense would have favored locating renewable energy development where it was most cost-efficient. In addition, it might have been noted that renewable energy incentives are best designed and implemented with the widest possible geographic scope, ideally corresponding to the region over which electricity is delivered and capacity competes. However, instead, every EU country wanted renewable energy investment, justifying – for example – incentives to build photovoltaic panels in regions of low solar irradiation.

Further, the complexity of the schemes across the EU created an administrative burden, raising costs to government departments. Piecemeal approaches favor inefficiency though facilitating social engineering and industrial policies. Complexity meant that comparing incentives between countries was difficult and frustrated the auditing of renewable energy expenditure. The complex EU renewable energy pricing structure, based upon different technologies, sizes, output, locations and usage, not surprisingly, has seen fraud and abuse. In the U.K., for example, higher incentive prices for smaller wind and solar facilities appear to have encouraged 'de-rating' of generation capacity to achieve higher prices.

Table 2. EU renewable energy support prices.

EU Renewable Energy Support Prices - 2010 €/MWh

Statistics	Solar PV	Solar Thermal	Wind Offshore	Wind Onshore
Average	€238	€109	€103	€97
Maximum	€490	€180	€160	€158
Minimum	€70	€65	€60	€66
Standard Deviation	€109	€33	€25	€24

Effectiveness versus Economic Efficiency

The renewable energy policies across the European Union were effective in getting capacity built. If policy success were measured by capacity and output alone, the EU's efforts would be viewed favorably. As Figure 4 shows, investment in renewable energy capacity led to growing output for many EU countries.

For the top 19 EU countries, renewable output more than doubled between 2004 and 2013. By this measure, the various incentive schemes were certainly effective in delivering renewable energy. From a policymaking perspective, the question is, however, whether similar levels of capacity and output could not have been delivered for less money. But how might the direct and indirect costs of the EU's renewable support schemes be examined?

Although actual expenditure by countries across the range of incentives is not available, we can use top-down approximations from the Council

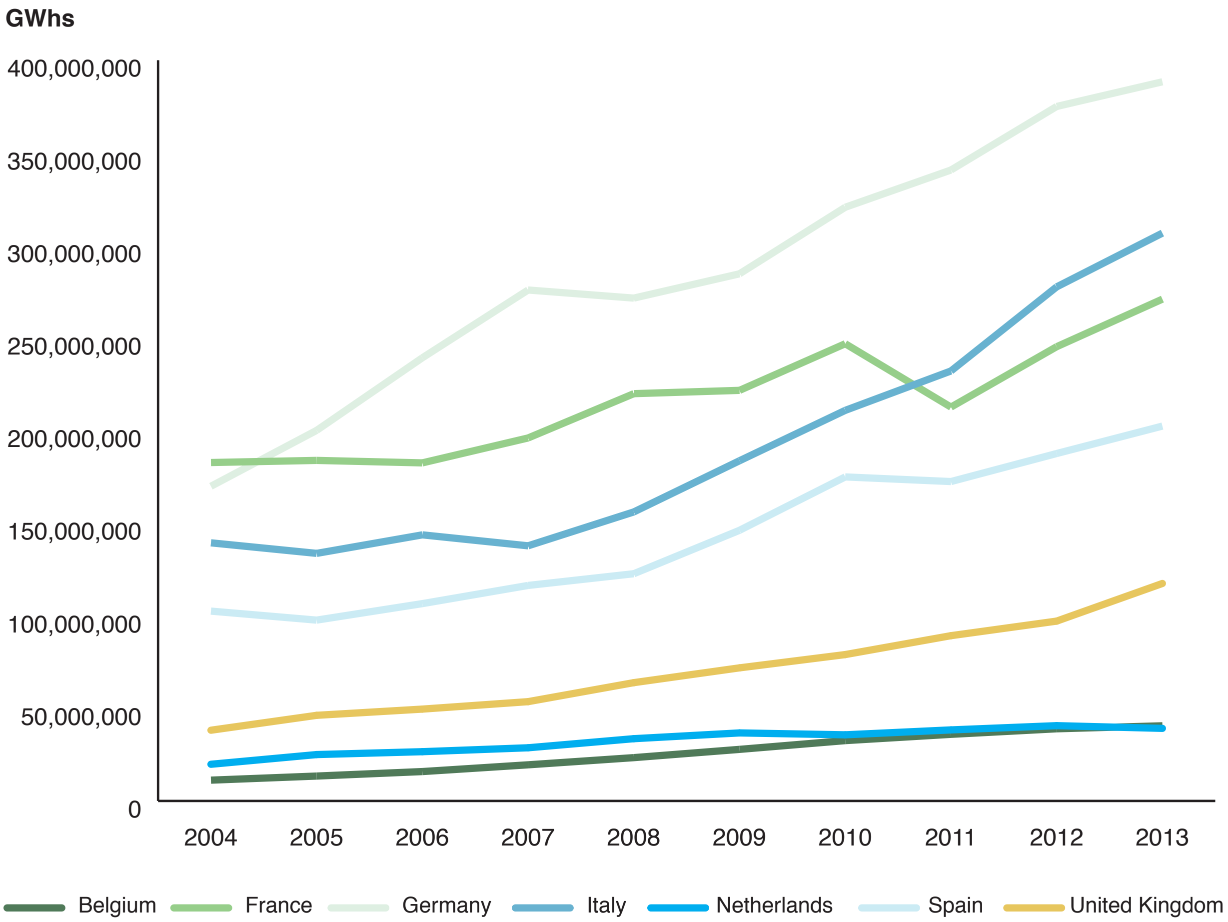

Figure 4. Renewable energy output by country.

Source: Euro Stat.

of European Energy Regulators (CEER) showing expenditure per MWh, for the gross categories of renewable energy. Using this data, the direct costs of subsidizing renewable energy and thus the earnings of renewable energy developers, owners and operators can be assessed and the issue of economic efficiency of incentives examined. As in Figure 5 below, across the EU between 2007 and 2009 the entire expenditure on renewable energy subsidies rose from about 9 billion euros to nearly 17 billion euros, according to CEER.

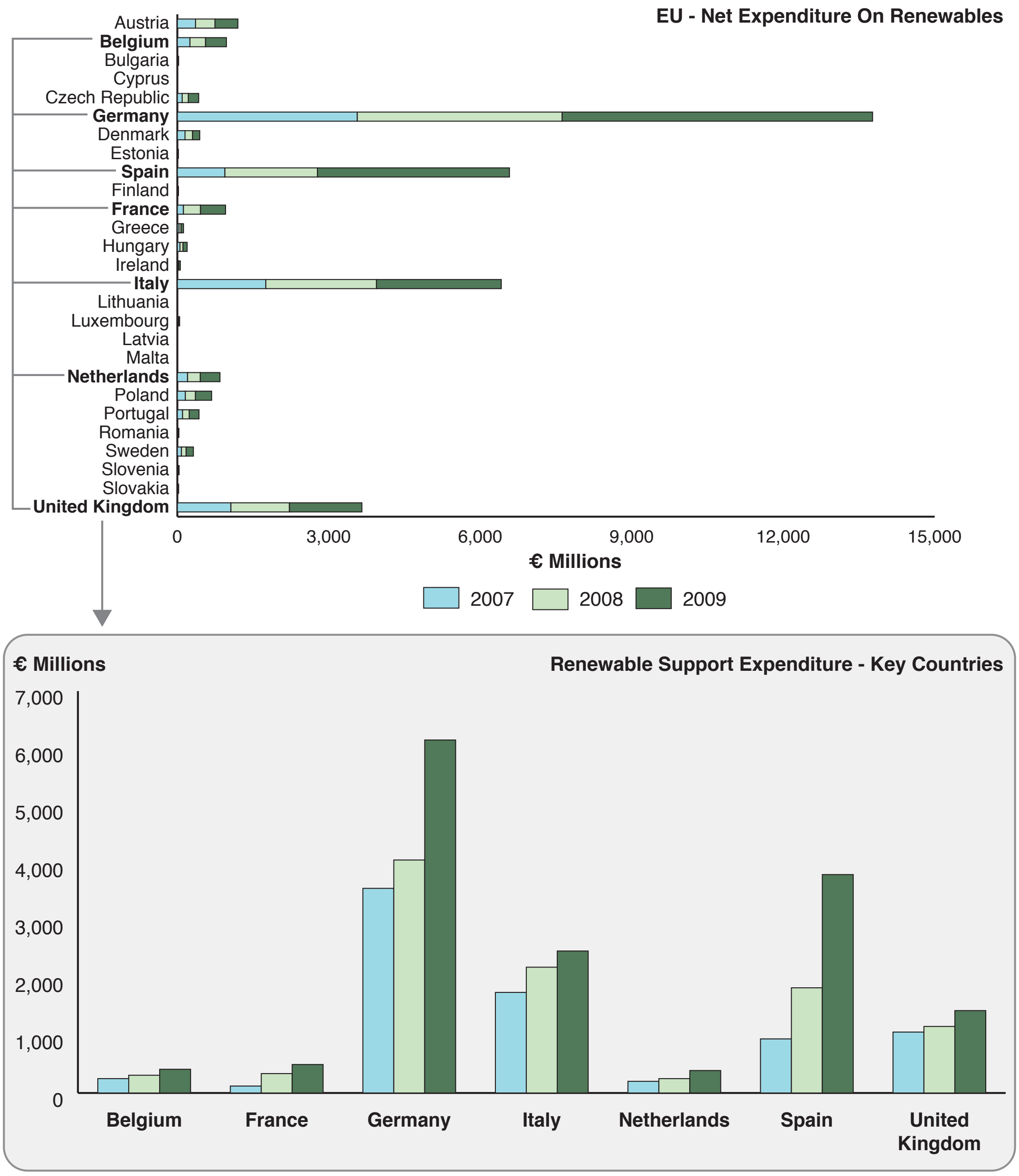

Figure 5. EU renewable support expenditure.

Source: EER.

Dividing net expenditure by output we can approximate the prices paid per MWh of renewable energy received. Table 3 and Figure 6 show through comparing wholesale market prices for electricity with renewable energy incentives (2009-2013) that the effective incentives were attractive. For solar PV, for example, the average EU incentive price was nearly eight times the traded wholesale price and roughly double for wind-generated electricity.

Table 3. EU incentive prices for renewable energy.

Top-Down Estimated of European Union Renewable Energy Incentives Prices by Technologies, 2009 - 2013 (€ per MWh)

2009 - 2013	Solar PV	Solar Other	Wind Off-Shore	Wind On-Shore
Minimum Incentive	€220.53	€68.04	€41.05	€41.05
Maximum Incentive	€496.03	€290.90	€35.50	€224.80
Average Incentive	€381.34	€177.34	€102.23	€92.60
Market Day-Ahead Average	€49.23	€49.23	€49.23	€49.23
Market Minimum Day-Ahead	€20.62	€20.62	€20.62	€20.62
Market Maximum Day Ahead	€148.51	€148.51	€148.51	€148.51

Source: Council for European Energy Regulators.

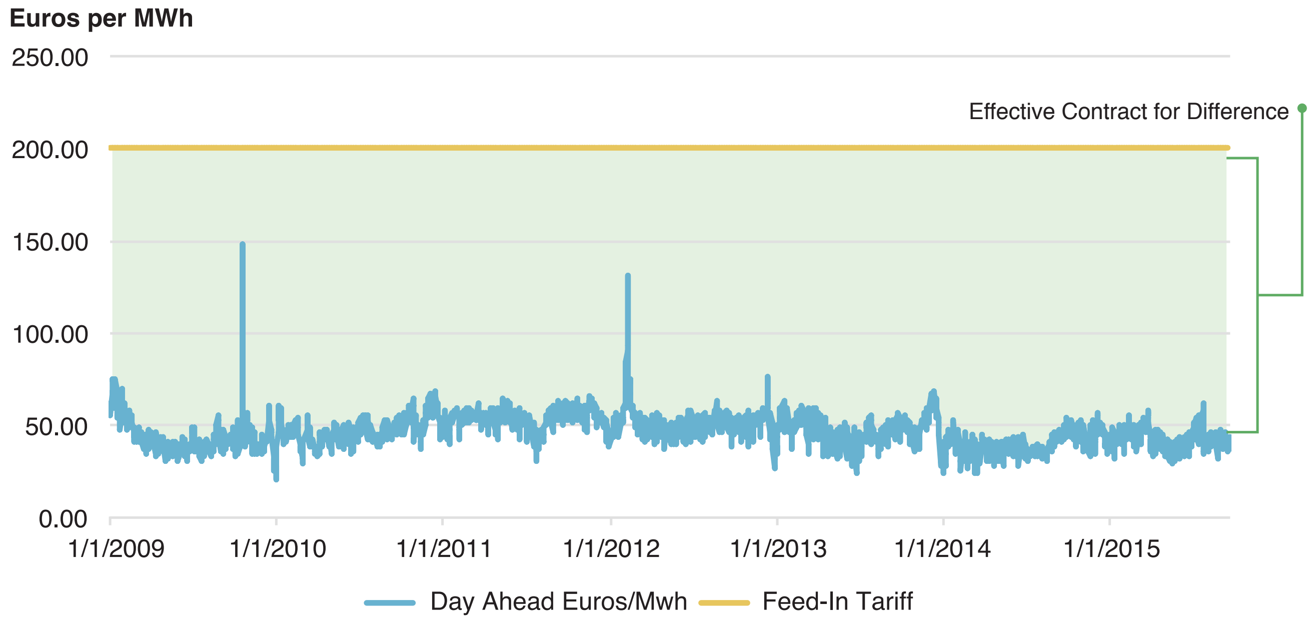

Figure 6. Contract for differences versus wholesale day-ahead power prices.

Source: Bloomberg.

Examining the returns conferred through the incentive prices in this way allows us to see whether the direct cost of subsidizing renewable energy made sense. Although not an approach taken by researchers and policymakers, we examine returns from an investor's perspective in order to assess whether the incentives were appropriate given the level of risks faced. Through generating a return on capital employed (ROCE), as shown below in equation (2), exceeding its weighted average cost of capital (WACC), a business creates economic value.

$$(2) \quad \text{ROCE (\%)} = \frac{\text{Earnings before interest and tax}}{\text{Capital employed}}$$

Capital employed is the capital required to buy renewable generation capacity and excludes any funding liabilities. As operating costs of renewable plant are low for wind turbines, especially during the first 10 years of operation, and even lower for PV (estimated at just 1 percent), such costs were excluded from earnings. Using published estimates for installed cost per MW of capacity for wind and solar energy from the U.S. DOE-EIA, we have computed the following results for ROCE across the major EU countries.

Table 4 shows that from an investor's perspective the renewable energy return on capital employed was very healthy, especially as the counterparties were investment grade utilities and national grids, and the entire program had sovereign backing. From the ROCE results we can see that reducing incentives significantly would have given investors in renewable energy a more than adequate return, especially at a time when the major utilities of Europe had ROCE of around 8 percent, earning less than their cost of capital of approximately 10 percent. These incentive levels could not have been justified on a risk-adjusted basis and demonstrate the generosity of the many schemes across the EU to subsidize wind and solar electricity generation. The magnitude of the ROCE returns helps to explain the rush to build renewable energy across the EU countries.

Table 4. Return on capital employed to renewable investments.

ROCE-Belgium, France, Germany, Italy, Spain, The Netherlands

Statistical Summary	Solar PV	Solar Thermal	Wind Offshore	Wind Onshore
Minimum	17%	1%	6%	3%
Maximum	50%	36%	16%	68%
Average	32%	18%	10%	25%

Source: Internal calculation.

Direct Costs of Renewable Energy

How were these direct costs met? The issue of fiscal incidence, that is who actually pays for a publicly funded expenditure, is key to policymaking. A subsidy to one entity is a tax upon another. In designing and setting incentive schemes in the EU there was only belated discussion of their costs, how they would be paid or on whom the burden would fall.

In Germany, it was suggested that the country's generation capacity could be brought to much greater reliance upon renewables at an almost negligible cost, which later proved to be inaccurate. Also in Germany, when there is an electricity shortfall — for example when wind turbines are not spinning and solar is not available — energy-hungry plants such as steel mills may be asked to shut down production to ensure the stability of the grid, but then ordinary electricity customers must later compensate the plant owners for lost profits. In Italy, solar power is subsidized through tariffs charged to consumers, which has raised energy bills in a country where the electricity price was already one of the highest in Europe. The current incentive schemes are projected to cost Italians 200 billion euros over the next 20 years — even with planned subsidy cuts. Across the EU in general, ultimately the consumer has paid for the

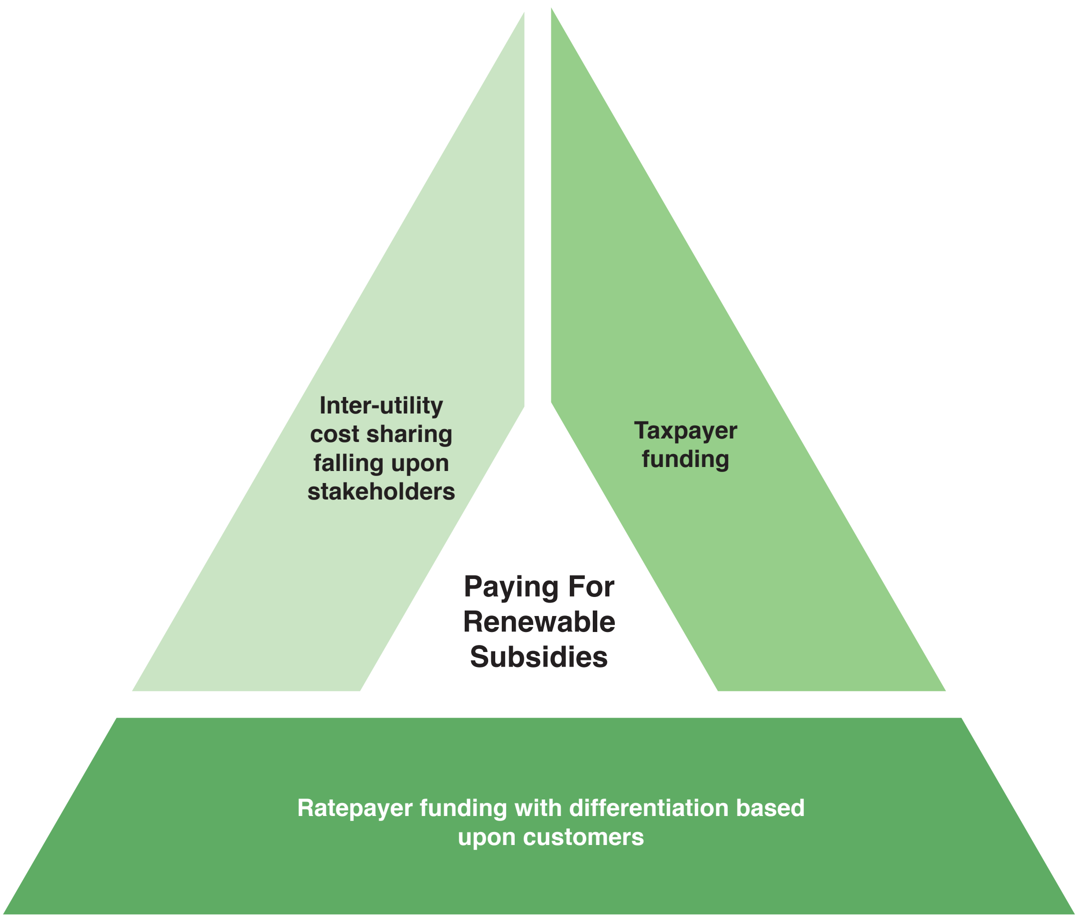

Figure 7. Paying for renewable subsidies.

subsidies and generous returns given to renewable energy owners, operators and developers. In some countries, such as Germany, most of the burden was placed upon retail consumers for fear that expensive renewable energy electricity would make German industry uncompetitive. In some countries, although the direct costs of renewable energy subsidies also fell upon industry, 'assistance' was provided to meet the costs of renewable energy, meaning an extra burden on tax payers — and challenging EU rules on state assistance. Direct taxpayer funding of renewable energy would have been the most transparent payment method, but arranging for the costs of renewable energy to be collected through ratepayer utility bills was politically expedient. Although the U.K.'s Office of Gas and Electricity Markets (OFGEM) was transparent on the costs of subsidizing renewable energy, disclosing how it resulted in higher bills for ratepayers, there was still publicity over rising electricity prices, leading to inquiries by the UK Competition Commission.

Acknowledging the direct costs of renewable energy has led to cuts in incentives in many countries including Bulgaria, Greece and Spain. Like carbon taxation, renewable energy obligations certificates have been used in some countries for the development and operation of solar and wind generation. The initial burden of this fell upon incumbent fossil fuel powered utilities but was ultimately passed forward to various stakeholders: to consumers in higher prices, in lower wages to utility industry employees and diminished returns to shareholders.

Between 2008 and 2014 the capitalization of the EU's integrated energy utilities fell by 500 billion euros, hurting pensioners and other investors. The pension weighting given to utilities shares, long the stalwarts of pension investments, has now been sharply reduced. Arguably, superimposing renewable energy on the existing liberalized market structure was producing unintended consequences.

In summary, we see that the direct cost of renewable energy incentives fell upon virtually all energy stakeholders in varying degrees. Only now have researchers and policymaking bodies begun to understand what the direct costs of renewable energy were and how they were paid. This has allowed stakeholders to look beyond the idea that, because the wind blows and the sun shines 'for free', renewable energy is cost-competitive. 'Green' job creation through renewable investment has also been cited to justify generous incentives for renewable energy, without identifying if such costs are reasonable and cheaper than alternatives. Being candid as to how much renewable energy was likely to cost might have created more economically sustainable policies and avoided the policy backlash resulting in the removal of some incentives and the perception by renewable energy advocates of an overreaction.

Indirect Costs of Renewable Energy

In addition to the direct costs of incentivizing renewable energy, renewable technologies place substantial indirect costs upon incumbent fossil fuel generators, integrated utilities and the grid as they struggle with having to purchase intermittent output at an incentive price. Just as a driver pays for vehicle insurance to use a car 24 hours per day but typically requires less than two hours daily, incumbent utilities and the grid face the costs of cutting their capacity to accommodate intermittent renewable energy output while selling less electricity, as well as other tangential costs such as reduced thermal efficiency and greater maintenance. Overall, throughout the day, utilities and the grid face the risk of having to accept electricity at an incentive price exceeding the market price. In effect, renewable energy owners and operators have a contract for differences, receiving the amount by which their premium or tariff exceeds the market price. Utilities and grid operators are exposed to having to pay this difference whenever wind or solar power is dispatched.

Typically, a renewable operator will enter into a long-term supply contract with a renewable aggregator or integrated utility that resembles a contract for differences between the market price and the price paid through the FIT or premium. The difference between the value stream to the renewable operator from a FIT or a FIP and the normal wholesale price of electricity that is faced by the purchaser of renewable energy creates an exposure for the buyer and ultimately a cost to society.

How can such additional cost be priced? We can calculate the additional costs of intermittent renewable energy using option theory because, in theory, half-hourly options conferring the right to sell electricity at a certain strike price — the FIT premium — could be used to offset or hedge the risk from having to take renewable energy at a high price that was based on feed-in tariffs, premiums or related mechanisms.

Following convention, owning a put option confers the right to sell an asset at an agreed price on or before a particular date and owning a call option confers the right to purchase an asset at an agreed price on or before a particular date. Both types of options confer the right to sell/buy an asset but not the obligation to do so.

As an oil producer might use put options to hedge against oil prices falling, or an airline hedge against a rising price of jet fuel through call options, a grid operator or utility could hedge, using put options, against the risk of having to take wind generated electricity throughout the day or solar power during daylight hours, at a price exceeding the wholesale price of electricity. Even though individual half-hourly options may not be sold and traded for every half-hour of the day, the price of the option represents the cost of the risk forced upon the grid and utilities.

Figure 8 illustrates how what the operator loses on the CfD may be offset by the put option. The dotted straight line rises above the horizontal because, as the market price for electricity falls, the mark to market (MtM) value of the feed-in premium or tariff increases. The utility or grid (operator) has a short position in renewable power — that is, the operator is obliged to purchase renewable power at the incentive price. As this operator is required to pay the incentivized price for renewableoutput, it loses as the market price of power falls. To hedge against the loss in value in having to purchase renewable energy at an incentive price, theoretically the operator could purchase put options. The gain from owning the put options — a long position — offsets and neutralizes the loss from the short position. (Note that the 'kink' in the put option line corresponds to the strike price. This is the incentive price, for example the FIT). Once the price of the put option is covered, as with having to pay for insurance, the buyer is compensated as the market price falls. But having the right to sell electricity greatly in excess of the market price is expensive.

If utilities or grid operators wanted to protect themselves against the CfD using put options, how much would it cost? While only standard options are traded and priced in the market, we can use option theory to price what it would cost a utility or generator to hedge all relevant half-hours against the cost of taking renewable energy. Based on forthcoming research, per MW of capacity basis,

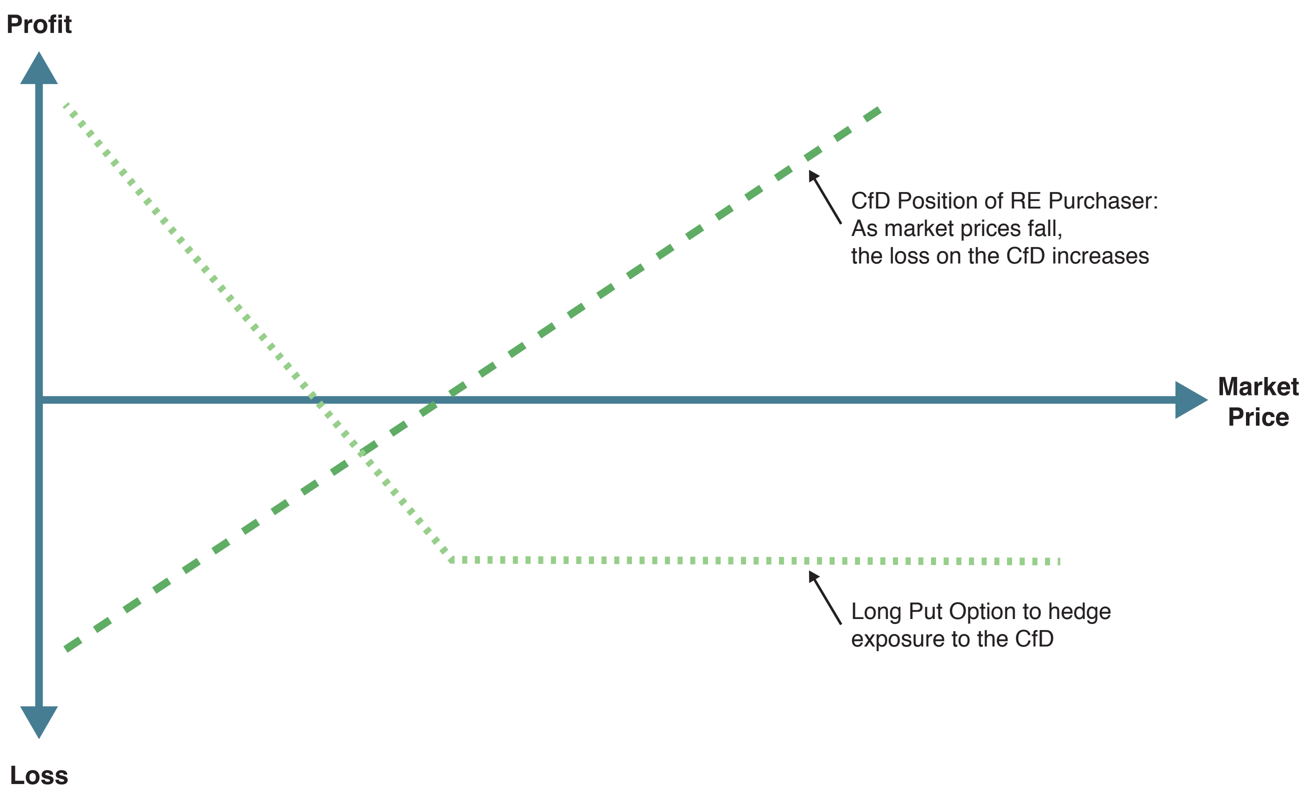

Figure 8. Hedging exposure to purchasing renewable energy under a CfD.

it would have cost more to hedge against renewable energy exposure than what was received by investors. Why? Because the strike price of the option equal to the incentive price greatly exceeds the wholesale market price giving it large intrinsic value or, in the language of option theory, making it deeply in-the-money.

As Table 3 showed previously, the incentive prices were considerably more than the wholesale traded price of electricity. So, in effect, to hedge the risk a utility or grid operator would have needed to buy deeply in-the-money put options. This is akin to having the right to sell crude oil at $150/bbl. when the market is $50/bbl. Such an option must be worth at least $100, and likely more, depending upon its duration and the volatility of the market. As Table 5 shows based upon our forthcoming published results, over the historic period 2009 to 2013 the cost of hedging with put options is nearly double what the renewable energy owner operator received.

Such hedging costs fall directly upon utilities and the grid, but ultimately affect all stakeholders from electricity consumers, utility employees and utility shareholders. As the above put options cannot actually be purchased, and if the utilities and grid as counterparties to the CfD cannot price the risks into the contracts with renewable energy producers, ultimately such costs have to be absorbed by utilities

Table 5. Renewable energy revenue and hedging costs.

Average Annual Renewable Energy Revenue 2009 to 2013 Per MW of Capacity vs. Cost of Hedging the Consequent Exposure

Average (Belgium, France, Germany, Italy, Spain, The Netherlands)	Solar PV	Solar Thermal	Wind Off-Shore	Wind On-Shore
Renewable energy 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

or passed forward to various stakeholders. The fact that the costs of the risk exposure are so high underscores the favorable deal the renewable energy producers and owners receive. They earn healthy returns while avoiding the costs of the externalities created. If such costs were internalized back to developers then, at least in the EU, it is unlikely that any renewable energy projects would ever have been built.

In sum, we see that there are several components to the total social costs of renewable energy. As shown in Figure 9, first there are the private costs that developers paid to build renewable energy capacity, then the costs of direct incentives paid to renewable energy developers and owners via their CFDs with the grid or utilities, and finally there are the large indirect costs of having to manage the intermittent outflow from renewable energy facilities. The latter may be estimated using option theory. Plus there are the additional connections and administrative costs of dealing with complicated schemes. We have excluded from our discussion the additional costs of distributed generation, additional transmission wires and metering, but these can be sizable.

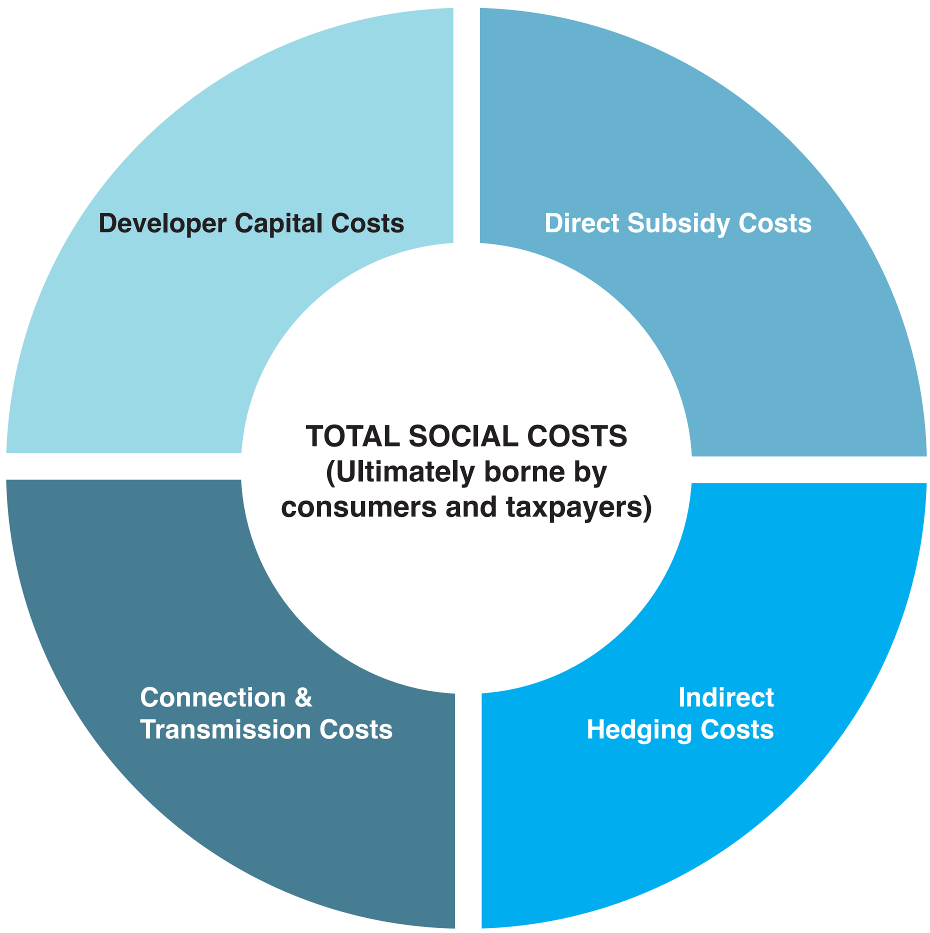

Figure 9. The social cost of incentives for renewable energy.

Conclusion

Although the costs of renewable investments have been falling, the cost per unit of output remains high because the fixed costs must be spread over fewer operating hours than conventional generation, including fossil fuel and nuclear.

In liberalized, competitive power markets, renewable energy requires subsidies because its low operating hours and intermittency mean it would not earn a sufficient return at market prices for electricity. The random nature of renewable energy output imposes costs upon grid operators and dispatchable generators, challenging the liberalized model of electricity markets.

No method of setting incentives for renewable energy, including cost based-approaches, value-based approaches or even market-based approaches like auctions, can guarantee cost efficiency. Indeed, the manner in which renewable energy was incentivized across the European Union was effective in delivering capacity and output but was inefficient from a cost perspective and provided excessive returns to investors.

Calibrating the design of subsidies and incentives from an investor's perspective could better ensure a normal rate of return to renewable investors rather than generous profits for little risk. However, the complexity and opacity in the design of the European renewable energy support schemes drove up costs, promoted inefficiency and contributed to abuse. In addition to the direct costs of subsidizing renewable energy, intermittency imposes indirect costs upon incumbent, dispatchable generators as they are forced to reduce capacity and accommodate electricity from wind turbines and solar PV. The indirect costs of accommodating intermittent output from renewable energy, imposed upon conventional generators in liberalized markets, are so large that in competitive markets for electricity, regulators have begun to consider paying for spare capacity and availability.

Altogether, while Europe has promoted an integration of energy markets to rationalize capacity and supply flowing to price, the piecemeal design of renewable incentives at country level led to inefficiency and suboptimal investment patterns.

Notes

Notes

About the Author

Lawrence Haar

Lawrence Haar, PhD, is a senior research fellow at KAPSARC working on the financial economics of renewable energy.

About the Project

Recognizing the limitations of common metrics for measuring how renewable energy should be incentivized and how its impact should be measured, the project on renewable energy in the European Union grows out of our academic research into calculating the direct and indirect costs of the various incentive schemes found in the United Kingdom and Europe.

Noting that the fluctuating output of renewable energy, at incentivized prices, under dispatch priority creates a cost for conventional generators forced to reduce capacity and reprioritize their plant, we introduce financial option theory to measure the burden upon conventional fossil fuel in hedging against the consequent exposure. The option analytic model was first applied to data for the United Kingdom before being used upon the major countries of the European Union, yielding similar results.

As detailed in our research, according to the metric return on capital employed, renewable energy support schemes produced generous rewards with little risks to private investors at a time when Europe's major energy utilities were earning less than their cost of capital. Using financial option method, we are able to calculate the indirect costs of renewable energy upon incumbents in managing random renewable output under dispatch priority, and find it to be very expensive.

The key outcome of this project is showing the economic inefficiency of the European Union support schemes for renewable energy. For the U.K. and the rest of Europe, the indirect costs imposed upon incumbent utilities and generators in accepting the output from renewable energy generators were significant with burdens falling upon all stakeholders.

مركز الملك عبدالله للدراسات والبحوث البترولية
King Abdullah Petroleum Studies and Research Center

www.kapsarc.org