Are green electricity certificates the way forward for renewable energy?

An evaluation of the UK’s Renewables Obligation in the context of international comparisons

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Abstract

This paper analyses the performance of the UK’s ‘Renewable Obligation’ in the context of other renewable energy procurement regimes. Prevailing wisdom suggests that market-based procurement regimes for renewable energy are more cost-effective than fixed price (‘feed-in tariff’) arrangements. In addition market based regimes are thought to favour corporate, rather than locally, owned schemes. However, the analysis in this paper disputes these strands of conventional wisdom. An analysis of the returns to wind power developers under the British ‘market based’ Renewables Obligation (RO) and the German ‘renewable energy feed-in tariff’ (REFIT) reveals that financial returns per MW of installed capacity are much higher in the case of the market based British RO compared to the German REFIT. On the other hand there is evidence that cultural factors are a bigger influence on the patterns of ownership of wind power schemes than whether procurement systems are ‘market based’ or ‘fixed price’.

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1. Introduction

The aim of this paper is to assess the extent to which ‘green electricity certificate’ trading schemes score more highly on cost-effectiveness and other criteria compared to other procurement systems. This task is accomplished by analysing the operation of the first two and a half years or so of UK’s ‘Renewables Obligation’ (RO). This discussion is placed in the context of a discussion of the effectiveness of the renewable electricity procurement mechanisms being used in other countries, including Germany.

Because of the global consensus on the need to reduce carbon dioxide emissions through, among other strategies, deployment of renewable energy, this is an important topic for analysis. On the other hand there is intense pressure from consumers and industry for electricity prices to be minimised. Hence it is important to discuss how the tension between these two conflicting aims, can be most effectively managed. In recent years attention has become focused on whether ‘market-based’ renewable energy procurement mechanisms can achieve these objectives better than other systems. At the time of writing the British Renewables Obligation appears to be the largest and most established of these market-based schemes. Hence my focus on the British Renewables Obligation.

I shall begin with some theory underpinning renewable energy procurement mechanisms, before moving onto to a practical discussion of the workings of the Renewables Obligation (RO). I shall then look at competitive trading systems being used in other
countries. In doing this I quote various costs. Please note that these reflects sums of money that are actually paid, or at least offered, as opposed to notional energy ‘cost’ estimates that are frequently bandied around but whose meaning depend on the criteria used.

2. Ideology and renewable electricity support systems

Since the end of the 1980s argument has raged over what constitutes the most effective means of encouraging the growth of renewable energy technologies. Various support schemes have been used, including direct capital grants, tax incentives influencing the price of renewable electricity production, tax incentives for investment in renewable energy schemes, competitive auctions of contracts to supply renewable electricity, ‘feed-in tariffs’ and market based schemes. Although, in practice, many of the schemes combine different incentives, ideological battle has been joined between proponents of the latter two types in this list.

Renewable Energy Feed-In Tariffs (REFIT) have been used to support what are to date the three biggest (in terms of contribution to national electricity requirements) renewable energy programmes in Denmark, Germany and Spain. At the end of 2004 these supplied, respectively, 21 per cent, 6 per cent and 8 per cent of electricity from wind power. European nations boasted around three-quarters of the 44 GWe of global installed wind power capacity. The REFIT model has powered most of the European total, including the 16.6 GWe installed in Germany. The feed-in tariff model assumes that there is a more-or
less ‘fixed’ schedule of payments, in money per kW/h for renewable electricity production, for a given period. In Germany and (from 2004) in Spain this period is 20 years in length, in France 15 years and in Austria 13 years.

However there has been criticism that the REFIT method has achieved volume growth in renewable electricity generation at the price of cost-effectiveness. Eurelectric, for example, which represents the European electricity industry, has criticised the German feed-in tariff for cost-ineffectiveness. Eurelectric, favours market-based frameworks that will avoid the creation of windfall profits, limit costs to energy consumers and make renewable electricity supplies more competitive with conventional sources. Eurelectric has called for a competitive pan-European market in tradable ‘green electricity certificates’ and harmonisation between the national support systems (Eurelectric 2004: 16-18).

The idea behind so-called ‘market-based’ schemes is to create a limited protected market for renewable electricity. Renewable electricity certificates are traded in a competitive arrangement. The creation of a single EU market in green electricity certificates, would, it is hoped, ensure that investment goes to the most cost-effective schemes.

At present, a pan-European market seems a distant idea. However, several states, including the UK, have set up ‘market-based’ schemes which, it is hoped, will procure green (renewable) electricity at a lower cost compared to feed-in tariffs. The UK’s
system represents the largest relatively ‘pure’ market-oriented target in the world. It began operating in April 2002, and we can make some comments about its operation.

This discussion about different renewable energy procurement systems has an ideological dimension, and, as Lauber (2004) has observed, proponents of market based systems operate from a neo-liberal perspective. This involves a combination of market based economics and a belief that state intervention acts to subsidise vested interests to the disadvantage of the public good, although neo-liberalism also implies that the state has a role in defining the nature of competitive markets when public goods are to be supplied (Toke 2000: 76-78). There is evidence that Governments which are associated with a more ‘welfarist’ approach, like Denmark, Germany and France have used the more interventionist REFIT model, whereas states with a more neo-liberal disposition, including the UK and the USA, have tended to adopt market-based mechanisms. The French example is complicated by the fact that before 2001 they had a competitive procurement regime for renewable energy, but it is still the case that the present ‘REFIT’ style system dates from the time of the socialist-green-communist coalition. Leading community-oriented wind power advocates such as Paul Gipe (http://www.wind-works.org/, accessed August 25th 2004) have favoured feed-in tariffs because of its association with high levels of local ownership of wind power by farmers and co-operatives in countries such as Denmark and Germany. There seems to be an ideological division, with the political right appearing to favour market-based procurement systems, and the political left favouring tariffs set by the government.
At one point, at the end of the last century, it seemed that the REFIT model was passing into history, just as neo-liberal ideas seemed to be triumphing at a broader political level. The European Commission expressed support for competitive arrangements on the basis that they would be more cost-effective than feed-in tariffs. (European Commission 1999).

The Danish Government then announced its support for a green electricity certificates trading system as a remedy to mounting criticisms that the feed-in tariff, which was partly funded by tax incentives, was a drain on public funds. A German electricity utility launched a court case (PreussenElektra v Schleswag) arguing that the German feed-in tariff was incompatible with EU Treaty state aid provisions and provisions on quantitative restrictions on imports. However, the revolution never quite happened. The European Court ruled against the German electricity utility and the Danish Government was persuaded, just before the 2001 Danish General Election, that the green certificates scheme was impractical. The right wing government which then took office decided not to introduce a green certificate system, although neither did they reinstate the old feed-in tariff arrangements.

In Britain, the first renewable programme, called the renewable energy Non-Fossil Fuel Obligation (NFFO) was financed by a levy on fossil fuels that was originally designed to fund a ‘nuclear obligation’. In a succession of five NFFO rounds in the 1990-1998 period, contracts were issued to developers of wind power and other renewable electricity sources. In a system that was designed to involve competition for contracts to supply renewable electricity, developers bid electricity prices for which they would be paid for output from their proposed projects. The lowest bids were given contracts.
This system produced some very low prices but few real schemes. **Average contract bid prices for wind power dropped during the course of the NFFO rounds so that by the end wind power contracts were being given away at 3 p/KWh, which is very low compared to the German feed-in tariff. However, this comparison was illusory for two reasons. First, the sort of wind power schemes being given contracts in the UK were on much windier power sites than in Germany. Moreover, very few projects resulted from the later NFFO rounds.** The bulk of the schemes were simply rendered uneconomic as developers seemed to bid for contracts to gain notional market share rather than establish economically viable projects (Mitchell 2000). **Developers seemed to gamble that the costs of wind generators would fall rapidly in the short term, or that exchange rates would shift in favour of buying from the dominant Danish manufacturers. British policymakers concluded that a different sort of competition was required.** Enter the Renewables Obligation.

### 3. The structure of the Renewables Obligation

The ‘Renewables Obligation’ (RO) encourages all electricity suppliers to meet an escalating target for supplying a proportion of their power from renewable sources. The target started at 3 per cent and rises incrementally to 10.4 per cent by 2010 and 15 per cent by 2015. It is likely to be extended to 20 per by 2020. The RO was given an artificial kick-start by incorporating the roughly 2 per cent of UK electricity that was supplied by renewable NFFO projects.
Electricity suppliers must buy ‘renewables obligation certificates’ (ROCs) from renewable generators to demonstrate supply of renewable electricity. If the suppliers fail to meet their targets then they must pay an (inflation-index-linked) ‘buy-out’ penalty of 3p/KWh or £30 per MWh (2002 prices). Crucially, this penalty is recycled as an extra reward in respect of each ROC that is issued. Under the British system if there is an under-supply of ROCs, their market value increases, (theoretically) encouraging more expensive generation to be developed to meet the gap in the renewable electricity market. The other parts of the income stream that are theoretically available to renewable energy generators include the baseload electricity price (1.7 p/KWh in 2002, although higher in 2004) and the levy on electricity consumption, or climate change levy to industrial consumers, at 0.43 p/KWh. Two questions emerge. First, does the operation of the RO live up to the hopes voiced by Eurelectric that market based systems will prove more cost-effective than the REFIT model in delivering renewable energy? Second, can this market based system deliver the required volumes of renewable energy?

4. The Renewables Obligation in operation

In fact, the RO has encouraged a larger volume of schemes with planning consent than what some of the headlines about opposition to windfarm proposals would suggest. By the end of November 2004 around 3500 MWe of wind power had been given planning consent in the UK. This would, if installed and added to other existing NFFO-inspired renewable electricity, be sufficient to supply around four per cent of UK electricity
requirements. Around 900 MWe of wind power had actually been installed by the end of 2004. Just over half the consented capacity is onshore (and two-thirds of that is in Scotland) and just under half is offshore. Installation is slow partly because of planning delays in strengthening grid capacity in South Scotland and partly because of delays in assembling financial packages for the relatively more expensive offshore windfarms.

Under the British RO (and other systems involving tradable green electricity certificates) there is a big difference between creating a market in ROCs and a market in renewable energy projects. The market in ROCs is a very competitive one, but most renewable energy generators require contracts over ten years in length. These contracts must specify appropriate levels of income in return for electricity to satisfy bankers and equity investors who provide the capital investment for the projects. In order to gain these contracts from the electricity suppliers the renewable energy generators have to exchange part of the value of the ROCs for the security that is offered by a long term contract with a credit-worthy electricity supplier. Hence rates of payment for renewable electricity that go to the renewable operators are set by the electricity suppliers who agree contracts with developers. Developers need secure long term contracts to persuade banks to lend them money. Of course it is entirely possible for a generator to be backed entirely by equity finance from a share issue, or from some large institution who can afford to fund the project without help from a bank. However few independent developers (that is independent of the major electricity suppliers) can achieve this.

So the reality of the Renewable Obligation is that it is mediated by the electricity suppliers who decide the terms of the contracts. It is their judgements (and fears) about
the long term shape of the market for ROCs that influence outcomes rather than (just) the actions of a large number of renewable developers. The UK electricity market is dominated by five or six major, trans-nationally owned, electricity suppliers who supply the bulk of electricity. Financial institutions are wary of the stability of the electricity suppliers, especially after the bankruptcies of two suppliers in 2003. As a result the biggest suppliers are the only suppliers with sufficient credit-worthiness for the banks to have confidence in their contracts, and only four or five of these major suppliers are said to be offering meaningful contracts to renewable electricity developers.

In the British market there some ‘independent power producers’, such as Renewable Energy Systems (backed by McAlpine), who own their own wind power capacity. However around 70 per cent of wind power capacity (as of December 2004) is owned by just four major electricity suppliers, Npower (owned by RWE), PowerGen (owned by E.ON), Scottish Power and Scottish and Southern Electricity (http://www.bwea.com/map/uk.html accessed 11/12/04). Centrica, another major electricity supplier, is investing in offshore windfarms. EDF, who are the only other acknowledged major electricity supplier have, as yet, relatively meagre investments in renewable energy.

The main electricity suppliers are capable of influencing the market price by their own actions through their control of investments and electricity supply contracts (in violation of the perfect market criteria). Given that the electricity suppliers are also the principal investors in renewable generation, then they have an incentive to protect those
investments from the potential of a crash in the price of ROCs. Indeed, their own individual (substantial) shares of the electricity supply market means that their own renewable investment strategies will have a significant impact on the overall market price of ROCs. If they fulfil their RO quotas then they will drive down the value of income streams going to their earlier renewable investments! In addition, the major electricity suppliers may be in danger of not having enough ROCs income to cover the commitments they have made to pay even independent renewable generators.

One does not have to conduct elaborate game-theory analysis to understand that the major electricity suppliers are unlikely to permit generation of sufficient renewable electricity to threaten the profitability of their own investments in renewable energy and the profitability of contracts they have issued to independent renewable generators. There is simply not enough competitive pressure to supply renewable energy to ensure low, so-called ‘competitive’, prices for renewable energy contracts. Hence it is an illusion to imagine, that if you set up a market, it is necessarily a perfect market where Adam Smith’s famous ‘invisible hand’ magically conjures up the most resource-efficient solution.

Electricity suppliers are offering two forms of contract. First, at least one leading electricity supplier is offering a flat-rate contract for a full fifteen years which is worth £50/MWh (5p/kWh) [Interviews with Bill Richmond of Your Energy (14/05/04) Gareth Ellis of the National Energy Foundation (22/11/04) Steven Brooks of Breeze Renewables Consultancy (27/10/04)]. Second, as an alternative, some electricity suppliers are offering
a ‘fallback’ basement flat rate tariff for renewable electricity that will satisfy banking demands for loan repayments and, at the same time, a formula of the elements of the income stream (whichever is the higher of the two). These formulae will involve high proportions of income from ROCs, lower proportions of income from recycled ROCs, plus a high proportion of baseload electricity prices and a high proportion of the levy on electricity consumption. The formula offers are resulting in out-turns in payments to the renewable generators of over £50 per MWh. The formulae offers are designed to give a good return to equity investors as well as repay bank loans (Interview with Colin Palmer of Wind Prospect (13/05/04)).

Of course, if developers are willing and able to make do with one year contracts, then they might expect a rather higher income. At the end of 2004, one year contracts were on offer from at least one electricity supplier that would yield around £70 per MWh (7p/KWh). This contract offer, for example, which covers just a year, involves payments to the renewable generators of all of the ROCs value, 80 per cent of the recycled ROCs payments as well as 85 per cent of the income from the levy on electricity consumption (climate change levy on industrial users) and good rates for baseload prices (contract offer made on 8/11/04 and unattributable personal communications 9/12/04). Generators can also sell their ROCs and other elements of their income streams via auctions organised by the Non-Fossil Purchasing Agency.

Only a few developers will be able to take on one year contracts because banks who lend money to developers want the security of long term contracts which have the firm
promise of ensuring the repayment of their bank loans. However, given that the availability of flat rate long term contracts of £50 per Mwh and also formulae contracts that can deliver, in the out-turn, rather more than £50 per Mwh, the average return to renewable electricity operators is likely to be in the £50 to £55 per Mwh range. Those who choose formula offers (or even one year contract offers) are effectively buffeted by the likelihood that the Renewables Obligation targets will remain significantly underfulfilled.

Considerable doubts have been cast on the ability of the ROCs system to achieve its own targets. As I said earlier, the electricity suppliers want to avoid a situation where there is an over-supply of ROCs leading to a crash in the price of, and market for, ROCs. This is made more acute by the fact that wind power output will vary from year to year by significant amounts, and the electricity suppliers will want to take account of this. The Renewable Power Association has estimated that because of these factors no more than 7 per cent of renewable electricity will be on line by 2010, and no more than 10-11 per cent by 2015, regardless of the extent to which problems with planning consent affect the market (Wolfe 2003). A House of Lords Report has come to broadly similar conclusions (House of Lords 2004).

It is difficult to argue, on the basis of the figures discussed earlier, that the RO is any more cost-effective than a feed-in tariff of, say, 5p/KWh, given that average income levels are likely to exceed this amount. This price should cover even those windfarms being set up in the relatively less windy area of East Anglia – given a 15 year contract. In
addition, this market based system does not prevent so-called ‘windfall profits’ from being earned since a developer in East Anglia will be offered the same contractual terms as a developer on a windy Scottish hillside. As one developer put it:

‘Whilst you’ve got a multiplicity of players, out there, they’ll all going to think, I’ll get my project in….. However, (in the short term) the Renewables Obligation does not actually produce great downward pressure on prices……Prices are set by the (major electricity) suppliers and they don’t depend on the wind speed of the site…so the profitability of windy sites is much greater than the profitability of low wind speed sites.’

(Interview with Colin Palmer, Development Director, Wind Prospect, May 13th 2004)

5. Renewables Obligation, offshore wind and other renewables

Onshore wind power developments are quite profitable under the terms of the RO. Yet, offshore windfarms are not nearly so profitable under these RO arrangements. Although the amount of wind energy at an offshore site will be, in an average years, 15-40 per cent more compared to an onshore site, (say, capacity factor of around 0.35 compared to around 0.3 for onshore), the capital costs of offshore schemes may be, on average, about 70 per cent higher (say £1250 per KW compared to £750 per KW for onshore).

This means that while onshore wind is viable for payments between about 3p/KWh and 5 p/KWh, offshore costs begin at 5 p/KWh and go up to over 6 p/KWh for some of the dozen schemes that have been given planning consent so far. In fact Round 1 offshore
schemes are receiving capital grants from the DTI of between 5-10 per cent in value of capital costs, which helps, but several of the offshore windfarms have struggled to obtain finance. The lack of a sufficiently high income stream has contributed to the unwillingness of banks to underwrite offshore windfarm investments. This means that the first UK offshore schemes are mostly being funded directly from ‘balance sheets’ of the electricity suppliers who also are acting as renewable developers and generators. The need to secure high income streams for their offshore windfarm investments is a powerful pressure on the electricity suppliers to maintain a high value for ROCs. Throughout 2004 there were doubts about whether some of the Round 1 schemes will be constructed, and Round 2 developments will depend on the allocation of more subsidies for the technology, perhaps through paying for grid connection costs.

Although the average cost of offshore schemes in the Government’s Round 2 offshore programme may be cheaper than Round 1, the difference may not be dramatic and offshore schemes will still be rather more expensive than most onshore schemes. This means that the current high rate for ROCs traded on the market will need to be more or less maintained indefinitely. The consequence of this is that Renewable Obligation must be significantly under-fulfilled if a large capacity of offshore windfarms is to be constructed.

The wind power industry is generally against major changes being made to the design of the Renewable Obligation. They fear that existing deals between generators and suppliers would unravel with significant changes, and that confidence in governmental renewable
energy policy would be fatally undermined. Marcus Rand, the Chief Executive of the British Wind Energy Association, has commented: ‘If the renewable obligation goes down we may never get another chance’ (personal communication March 11th 2004).

There is a national consensus in favour of ambitious renewable energy targets, and this includes the Conservatives who are critical of onshore wind power. Yet the possibilities for commissioning large quantities of non-wind power renewable energy technologies under the current design of the RO seem remote. This is because the alternatives require higher tariffs for their electricity than are probable under the RO. Solar electricity is very popular, but it is also, currently, many times more expensive than wind power. The Germans pay a feed-in tariff for solar photovoltaics of 35 p/KWh. There are some niche markets for types of biomass, chiefly dealing with waste materials. However electricity from fast-growing trees, for example, is often going to be much too expensive for the RO. It may be practical to co-fire biomass in conventional power stations, but options for this are limited by operational and economic factors.

Wave power and tidal stream technologies have been awarded some DTI research and development grants. They are still significantly more expensive than wind power. Price based incentives, whether feed-in tariffs or capacity obligations, are needed to provide the pressure for commercial deployment and downward pressure on capital costs. The capital costs for wave power plant are at much the same level as applied to onshore wind power in the early 1980s when commercialisation was beginning. A feed-in tariff of around 15 p/KWh might support British offshore wave power projects.
6. Other procurement regimes

It is important to make some comparisons with other renewable energy procurement regimes. Let us begin with other ‘market-based’ schemes. These are popular in the US. Indeed, some 13 states now claim to have so-called ‘Renewable Portfolio Standards’ (RPS). In fact over half the capacity in these systems is not bound up with obligations involving tradable renewable electricity certificates, and it is a misunderstanding to think of even the more market-based RPS systems as wholly comparable to the British RO. This is because renewable energy deployment is heavily reliant on the Federal ‘Production Tax Credit’ of 1.9 c/KWh. This is a sort of ‘rich man’s feed-in tariff’ because it works through actors (usually corporates) with high tax liabilities being able to gain tax benefits if they invest in wind power.

Nevertheless, there is only significant renewable development in the states with RPS systems. Such mandates, backed by state law, make the utilities contract renewable energy which, unlike the UK, includes large quantities of electricity from geothermal and biomass. Probably the most cited RPS (in terms of success) exists in Texas where the target of 3 per cent of electricity from renewable sources by 2009 was over-subscribed at an early stage. This is evidence that the system works well, but the oversubscription and the relatively low cost of the wind power has much to do with the good wind regimes available in Texas and the fact that utilities rushed to contract wind power because of
uncertainties over when the Federal production tax credit would be renewed (Langniss and Wiser 2003).

The largest American renewable energy target of them all, set by California, of 20 per cent of electricity from renewables by 2017, does not actually involve a market based system. Rather, the California Public Utilities Commission oversees the construction of a cost ‘merit order’ of renewable capacity (by the major utilities) which is then matched with subsidies. It remains to be seen how this will translate into practice. However, California and other states involved in the western electricity pool (one of six grids in the USA) are discussing a system for validating renewable electricity certificates (Xenergy 2003). Such RPS certificates could be traded between states with RPS standards, perhaps regardless of differences in subsidy for renewable energy.

Conecticutt has ambitious targets (13 per cent by 2009). This state has a penalty for non-compliance on suppliers of 5.5 c/KWh, which when added to the production tax credit and payments for baseload electricity produces a slightly better price for renewable energy than is available to developers in the UK. Conecticutt is also interesting because it is in the New England electricity pool where RPS systems exist in four other states and where green electricity certificates can be transferred from state to state. Sunny Nevada has a separate obligation for solar electricity and another effectively for wind power. All the RPS systems operating in the states have fixed penalties for non-compliance but, unlike the UK’s system, penalties are not recycled (UCS 2004 and a series of interviews with officials of various state Public Utility Commissions).
Australia also has a market-based system in which the penalties on electricity suppliers for non-compliance are not tax-deductible (unlike renewable investment costs). However, Australia has a low target of 2 per cent by 2010.

Compared to Britain or Texas, it may appear that German feed-in tariffs are expensive, given that the German feed-in tariff is set at 9.1 eurocents or 6.1 p/KWh for schemes that began before 2004, and 8.7 eurocents (or 5.8 p/KWh at 1.5 euros/£) for schemes starting in 2004 or later. However, these figures are illusory for three reasons. First, because the German tariffs decline over the 20 years of fixed payments, to a second stage of payments of only 5.5 eurocents/KWh. A second reason is that baseload electricity prices have tended to be higher in Germany compared to, say, the UK. Hence the amount of effective subsidy for renewable energy in Germany may not be as great as it would seem. The third, and biggest, reason why the nominal rate comparisons with other countries' renewable electricity tariffs may be illusory is that windspeeds at typical German sites are very much lower compared to typical sites in the UK or Texas. In Germany even the best sites have wind speeds that would be of only marginal interest to the main wind power developers in the UK.

This is demonstrated by comparing average capacity factors in different countries. A capacity factor is the amount that wind turbines generate compared to what they would generate if they were producing full power continuously over a given period of time. We
can then multiply these capacity factors by the rates payable in the different countries in amounts per kWh to derive a return per installed kW of wind power.

We can calculate capacity factors by dividing the actual production of electricity divided by the maximum that could be generated from a given unit. National capacity factors can derived by aggregating these figures from all the units for a given country in a given year. I have used three years, 2001, 2002 and 2003 (that is, data that is available to me) as a baseline for calculating capacity factors for German and British wind production, as is shown in Table 1.

There is a problem in calculating the capacity factors because there has been rapid deployment of wind power during each of these years producing significantly different end-year figures for installed capacity as opposed to capacity installed at the start of each year. However, this problem can be overcome by taking an average installed capacity over each year. Following inspection of installation rates in Germany and the UK it appears that around twice as much capacity is installed in the latter half of the year (to catch the winter wind) than in the earlier part of the year. Hence a weighted average is used which adds the capacity at the start of each year to a third of the capacity built in the given year.
Table 1 Capacity factor calculations for Germany and UK wind power

2001-2003

<table>
<thead>
<tr>
<th></th>
<th>Capacity(Mw)</th>
<th>weighted average</th>
<th>Production Gwh</th>
<th>capacity factor</th>
<th>Average 2001-2003</th>
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<td><strong>Germany</strong></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>2001</td>
<td>6100</td>
<td>8754</td>
<td>6984.667</td>
<td>10509</td>
<td>0.172</td>
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<tr>
<td>2002</td>
<td>8754</td>
<td>12001</td>
<td>9836.333</td>
<td>15856</td>
<td>0.184</td>
</tr>
<tr>
<td>2003</td>
<td>12001</td>
<td>14609</td>
<td>12870.33</td>
<td>18919</td>
<td>0.168 0.175</td>
</tr>
<tr>
<td><strong>United Kingdom</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2001</td>
<td>406</td>
<td>474</td>
<td>428.6667</td>
<td>965</td>
<td>0.257</td>
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<tr>
<td>2002</td>
<td>434</td>
<td>522</td>
<td>463.3333</td>
<td>1256</td>
<td>0.31</td>
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<tr>
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<td>625</td>
<td>556.3333</td>
<td>1286</td>
<td>0.264 0.277</td>
</tr>
</tbody>
</table>

The average capacity factor (see right hand column) over these three years is 27.7 per cent for the UK, and 17.5 per cent for Germany (Data sources for capacity and electricity production [all accessed on August 30th 2004]: Digest of UK Energy Statistics, http://www.dti.gov.uk/energy/inform/dukes/; British Wind Energy Association, http://www.bwea.com; Verband der Netzbetreiber http://www.vdn-berlin.de, Deutches Wind Energie Insitut, http://www.dewi.de).

I have then calculated the annual payment per kW of installed capacity in the UK and Germany and compared the result. Annual payments per kW of installed capacity can be calculated by multiplying one (kW) by the average national capacity factor, then by the pence per KW/h payable to renewable generators and then by the number of hours in the year (8760).
I assume, for the purpose of this analysis, that the feed-in tariff for Germany is 8.7 eurocents/KWh, even though in practice this declines through the life of each scheme and, arguably, is more like 8 eurocents/KWh. If this is the case then this analysis therefore exaggerates the subsidies given to German wind power. I use the figure of 5p/KWh as the tariff for renewable electricity for long term contracts under the RO. As discussed earlier this is likely to underestimate the out-turns of income receipts by renewable generators. Hence the annual return for any investment in a kW of wind power in the UK is calculated:

\[1 \times 0.277 \times 5.0 \times 8760 = £121.33\]

I shall assume, for the purposes of this analysis, however, that the German feed-in tariff is 8.7 eurocents/KWh or 5.8 p/kWh, 1.5 euros being taken as the long term equivalent of the £.

Hence, for Germany the annual return per kW of installed wind power is:

\[1 \times 0.175 \times 5.8 \times 8760 = £ 88.91\]

Thus, annual payments per kW of installed wind power are at least 27 per cent lower in Germany compared to the UK – and as argued earlier, the real disparity is likely to be larger than this. So, in fact, the German feed-in tariff actually gives a much lower subsidy per quantity of installed capacity than is the case in the UK.

Part of the explanation for this difference will lie in different tax regimes. In Germany private investment in capital investment, as a general rule, is tax deductible, and marginal tax rates can be over 50 per cent for the highest income groups. This makes investment much cheaper in Germany (for the wealthy), in Germany compared to the UK.
In addition, farmer and co-operative windparks are cheap to set up since they can avoid significant portions of development cost. They can organise the developments themselves in collaboration with agents of wind generator manufacturers and low-cost consultants. Developers have large staff and establishment overheads which farmers and citizen’s co-operatives do not have to bear (many interviews with a range of farmers, co-operative organisers, wind generator manufacturer agents and consultants 1999-2004, most recently Hans Detlef Feddersen 2/09/04).

Whatever such arguments may be, it does seem that there is no evidence to support the notion that somehow German wind power operators are earning ‘windfall’ profits compared to UK operators. The annual return on capital invested in wind power in Germany is not greater compared to that of the UK. On the contrary, it seems to be much lower.

Eurelectric have claimed that the published German feed-in tariff does not include extra costs (2.4 eurocents/KWh or 1.6 p/kWh), e.g. for back-up by conventional plant that has to be borne by electricity suppliers. Eurelectric’s estimates of such costs are controversial, and in any event, represent extra costs that would, under the UK’s Renewable Obligation as well as under the German feed-in tariff, have to be borne by electricity suppliers. Ironically, it is the German system, as well as the more recently started French system, which varies payments according to windspeeds and thus offers hope for cutting out ‘windfall’ profits that fall to developers on high-windspeed sites.
The prospects for harmonisation of renewable procurement regimes in Europe seems remote, at this time, but if US activists can conceive of trading in green electricity certificates between systems with different incentive systems then the same is possible between EU states. However in Europe nationalism may pose a threat to transferable green electricity certificates. A Dutch (consumer demand-led) green electricity trading scheme has been abandoned because of opposition to the effective use of Dutch subsidies to pay for renewable electricity sources from abroad, principally Norwegian hydro-electricity. In fact the design of the scheme exacerbated the problems since Dutch taxpayers, and not just those who opted for green electricity, were effectively subsidising the Norwegian hydro operators. The Feed-In tariff that has replaced this market-based system is under attack from Dutch developers because the subsidies are only payable for a relatively short operational period.

Free-market inspired grand designs of harmonising national renewable energy support measures (which is not absolutely necessary for pan-European trading in green electricity certificates) needs to be treated with caution. If a consequence was that incentives for wind power were reduced still further in Germany (they have already been scaled down) we have to consider whether all of the German farmers and others who could no longer invest in economically viable schemes their own neighbourhood would instead invest in wind power in, say, Scotland. A German farmer’s interest in wind power tends to be driven by its feasibility on their land rather than pure technological interest in wind power.
7. Do market-based trading systems favour the big corporations?

There does seem to be a general impression abroad that market-based instruments will favour multinational capital as opposed to feed-in tariffs which may allow locally owned wind power schemes to prosper. A comparison of different forms of ownership is given in Table 2 below.

It is clear that feed-in tariffs do not necessarily lead to community wind power. Spain, which uses a feed-in tariff, is even more dominated by corporate investors than is the UK. Spain’s low population density is one of the factors which may explain why planning controversies have not been as intense as in England and Wales.

Table 2
Ownership of Onshore wind power in selected EU countries by Per Cent Capacity

<table>
<thead>
<tr>
<th>Type of owner</th>
<th>UK</th>
<th>Germany</th>
<th>Denmark</th>
<th>The Netherlands</th>
<th>Spain</th>
</tr>
</thead>
<tbody>
<tr>
<td>Utilities/corporate</td>
<td>98</td>
<td>55</td>
<td>12</td>
<td>32</td>
<td>99+</td>
</tr>
<tr>
<td>independent</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>farmers</td>
<td>1</td>
<td>35</td>
<td>63</td>
<td>62</td>
<td>&lt;0.5</td>
</tr>
<tr>
<td>Co-operatives</td>
<td>0.5</td>
<td>10</td>
<td>25</td>
<td>6</td>
<td>0</td>
</tr>
</tbody>
</table>

25
Local ownership of wind power schemes has been associated with higher levels of planning acceptance compared with ownership by remote corporations. As a Danish Government report said:

‘The local environmental disadvantages of wind power can lead to a lack of public acceptance of wind farms. Local ownership of wind turbines (local farmers, co-operatives or companies) can ensure local acceptance of projects. (Andersen 1998: 7)

In Germany, even much of the corporate sector consists of companies financed by public share offers to high income earners. This is partly because the utilities were actually excluded from the right to receive the feed-in tariff for wind power developments until 2000.

Co-operatives involve large numbers of people in wind power, hence enlarging the pro-wind power lobby at a both local and national level. Enthusiastic farmers can deploy their local contacts to reduce the scale of planning controversies compared to outside utility or corporate-funded developers. It is plausible to argue that the lack of farmer and co-operative ownership in the UK has significantly exacerbated planning controversies. More local ownership might mean more projects being proposed in the first place. At the end of November, in the UK, there were only around 12.5 MW of installed farmer and
co-operative wind power capacity in four schemes (http://www.bwea.com/map/uk.html), although a small number of other schemes are in the planning pipeline.

There is evidence that market-based schemes do not inevitably favour corporate capital over local ownership. The Dutch system of tradable green certificates, in the 1996-2002 period, co-existed with a big increase in the number of farmer-owned windfarms. The fact that the electricity market, generally, was being liberalised, allowed farmers access to more than one utility in their search for adequate contracts to supply electricity. Their bargaining position was advanced generally by the fact that they were able to form a lobby to obtain better terms from the electricity suppliers (Breukers and Wolsink 2003).

Neither does the UK’s Renewable Obligation necessarily block farmer-owned or co-operative wind power schemes. Certainly at the very beginning of the RO, there were practically no real long term contracts being offered to independents of any kind, and hence descriptions of the RO (taken from this period) as involving high risk for developers seemed accurate (Mitchell et al forthcoming). However, matters improved after the UK Government (in December 2003) signified the extension of the Renewable Obligation to 15 per cent of electricity supply by 2015. As discussed earlier, electricity suppliers have been offering long term (15 year) contracts for 5 p/kWh as well as attractive formula offers for long and short-term contracts. There is a widespread expectation that such terms will persist because there will be a considerable shortfall in the RO targets. The relatively few farmers, co-operatives and developers that are
genuinely independent of big corporations that have gained planning approval for their schemes seem to be gaining acceptable contractual terms for the sale of their electricity.

There is an argument to say that perceived financial insecurity of the ROCs system may deter farmers and co-operatives from entering the market. There is no legal guarantee that the ROCs market will not collapse. However, as discussed earlier, it is very much in the interests of the oligopolistic electricity suppliers that this does not happen. Furthermore there remains evidence that determined individuals and groups can set up schemes. In one sense RO offers opportunities to farmers and co-operatives precisely because it does not function as a market instrument that would push down prices, and in another sense because farmer and co-operative schemes are actually fairly cheap to set up (especially compared to offshore windfarms).

Certainly, UK banks do not (yet) lend money to smaller projects with the ease that finance is offered to farmer-owned concerns in The Netherlands, Germany and Denmark. However, money is still available from sources such as Triodos Bank, and also from German companies such as Energiekontor who are eager to grasp the high returns that are available on the British market (Interview with Huw Smallwood 11/11/04). These conditions allowed, for example, the Moel Maelogen project in Wales to (organised by three farmers led by Geraint Davies) to be established. The farmers acted as their own developers (Loring 2004, 224-232) and in November 2004 they won planning consent for an extension of their project.
A key reason that there are established mechanisms favouring local ownership in Germany, The Netherlands (and formerly) in Denmark is because there has been large numbers of enthusiasts who have been determined to spend time effort and money to circumvent barriers. Locally based agents of wind generator manufacturers and the co-operatives played an important role in spreading information about local ownership of wind power. Once a market of for farmer investment exists, banks and electricity suppliers tailor their services to meet this market. Ethical investment banks and ‘green electricity’ suppliers already appear willing to finance such operations in the UK.

The ROCs system may actually provide some great opportunities for the type of ‘Bürgerwindparks’, or citizen-investor-owned schemes that proliferate in Germany. A farmer in southern England called Adam Twine is developing a 6.5 MW project at a relatively low UK hub-height windspeed of 6.5 m/s. This is being financed by a co-operative share offer organised by the company Energy4All (Interview with Adam Twine 12/08/04). The offer will be taken up by mostly small investors who, as ethical investors, will not be as concerned as institutional investors about the precise level of rates of return. As discussed earlier, projects such as this can obtain most of the market value of their ROCs, the returns from this amounting to around 7 p/KWh for annual contracts starting at the end of 2004.

The problem with the UK may be cultural in that there simply are very few farmers (to date) or co-operatives trying to deploy schemes. Whereas in Denmark, Germany and in The Netherlands there have been many local enthusiasts prepared to put a lot of time,
energy and their own money into wind power schemes, in the UK the level of grass roots activity has been very weak. The small number of enthusiasts for alternative technology in the UK have tended to start up large-scale development companies, or become consultants offering services to existing developers, rather than starting co-operatives or helping farmers to develop schemes (Toke 2004).

8. Conclusion

The evidence does not support any contention that the RO supplies renewable electricity more cheaply than a feed-in tariff. The RO is relatively inflexible in that it effectively sets a single level of payments for all renewable energy generators that is relatively generous for onshore wind power, barely sufficient (even with capital grant supplements) for offshore wind power, and not enough for much else. Its target of supplying 10 per cent of UK electricity from renewables by 2010 is really more like 7 per cent.

On the other hand the RO is set to deliver significant amounts of renewable capacity and fundamental changes to the design of the RO could jeopardise this progress. Wider experience suggests that well-designed market based obligation procurement regimes can work effectively, although progress in the US seems to be at least as reliant on the federal production tax credit subsidy as much as the (sometimes) ‘market’ state-based obligations.
Market-based procurement systems depend heavily on their design rules for their success. Moreover, the more ambitious the targets are, the more expensive will be incentives (or penalties) needed to ensure compliance with the targets. Evidence suggests that there is a lot of fashionable mythology about renewable energy procurement regimes. Feed-in tariffs are not more expensive than market based systems. Indeed currently the political pressure on feed-in tariffs to reduce subsidies is probably hampering their ability to carry on delivering large new volumes of renewable energy. On the other hand, feed-in tariffs are not necessarily better than market-based systems in supporting projects owned by farmers or co-operatives. Wind power becomes cheaper as wind generator manufacturers compete with each other to design more efficient machines, not because procurement regimes, which inevitably involve some form of subsidy, are made more ‘competitive’.

In practice procurement regimes work if they give good price incentives. Indeed the fact that the British RO is not as cost effective as a feed-in tariff is a good thing if the objective is to achieve rapid deployment of wind power. The challenge is to improve and diversify this system both in terms of ownership and technology without interrupting the progress that is already being achieved.

References


Tomlinson, C (2004) *Another Approval!!!* E mail circular to members of the British Wind Energy Association, 01/07/2004


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