WHY IS WIND POWER SO EXPENSIVE?

AN ECONOMIC ANALYSIS

Gordon Hughes

Foreword by Baroness Nicholson of Winterbourne

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Baroness Nicholson of Winterbourne
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Foreword by Baroness Nicholson of Winterbourne

While the environmental damage caused by onshore wind farms is arousing increasing concern, the cost of wind energy is also a very important topic. Indeed, I believe it has been underresearched, underdiscussed and underdebated.

I believe that when taxpayers know the truth about the subsidies that wind turbines have attracted, they will not be at all comfortable that their hard-earned income is being spent in this way. It is an unhappy fact that wind farms are almost entirely subsidised by a complex yet hidden regime of feed-in tariffs, tax cuts and preferential tax credits.

A typical turbine generates power that is worth around £150,000 a year, but attracts subsidies of more than £250,000 a year. These subsidies are of course added directly the bills of energy users.

The cost to consumers of the Renewables Obligation scheme alone has risen from £278 million in 2002 to more than £1 billion in 2011, which is a total growth of £7 billion over nine years.

As Gordon Hughes's report shows, meeting Britain's target for renewable energy by 2020 would require a total investment of some £120 billion in wind turbines and back-up. The same amount of electricity could be generated by gas-fired power plants that would only cost £13 billion, that is an order of magnitude cheaper.

An analysis of wind patterns in the United Kingdom suggests that wind generation offers a capacity usage of between 10 and 20 per cent of theoretical capacity, which in itself is an indicator of how much of the capacity can be statistically relied on to be available to meet peak demand. It compares with around 86 per cent for conventional generation.

This means that fossil fuels still have to be available as a back-up in times of high demand and low wind output if security of supply is to be maintained. So new conventional capacity will still be needed to replace the conventional and nuclear plants which are expected to close over the next decade or so, even if large amounts of renewable capacity are deployed. To put it plainly, this means that every 10 new units' worth of wind power installation has to be backed up with some eight new units' worth of fossil fuel generation. This is because fossil fuel sources will have to power up suddenly to meet the deficiencies of wind. Wind generation does not provide an escape route from fossil fuel use, but embeds the need for it. It is clear that wind power does not offer a decent alternative to fossil fuels.

Government plans to construct thousands of wind farms have been thwarted by a growing tide of public opposition. The percentage of wind farms being refused planning permission has risen sharply. Last year, nearly half of all onshore wind farms in England and Wales were refused planning permission. More than 100 MPs have recently written to the Prime Minister to criticise the economic and environmental folly of wind farms, demanding that the billions in subsidies wasted on these schemes be slashed.

The total consumer bill for wind subsidies by 2030 is estimated to amount to a staggering £130 billion. A recent analysis of UK wind farms revealed that a dozen of the biggest landowners will between them receive almost £850 million in subsidies, a huge amount of funding that will be paid by ordinary families through hidden taxes on their household electricity bills.

I am immensely unhappy that our intermittent wind power has attracted such monstrous subsidies. I am particularly unhappy because the facts have been hidden from the consumer who will have to pay the bill for this folly. Gordon Hughes's excellent report is a timely contribution to educate policy makers and the wider public about the fatal flaws of Britain's wind obsession.

Summary

1. Wind power is a capital-intensive means of generating electricity. As such, it competes with electricity generated by nuclear or coal-fired generating plants (with or without carbon capture). However, because wind power is intermittent, the management of electricity systems becomes increasingly difficult if the share of wind power in total system capacity approaches or exceeds the minimum level of demand during the year (base load). It is expensive and inefficient to run large nuclear or coal plants so that their output matches fluctuations in demand. Large investments in wind power are therefore to undermine the economics of investing in nuclear or coal-fired capacity.

2. The problems posed by the intermittency of wind power can, in principle, be addressed by (a) complementary investments in pumped storage, and/or (b) long distance transmission to smooth out wind availability, and/or (c) transferring electricity demand from peak to off-peak periods by time of day pricing and related policies. However, if the economics of such options were genuinely attractive, they would already be adopted on a much larger scale today because similar considerations apply in any system with large amounts of either nuclear or coal generation.

3. In practice, it is typically much cheaper to transport gas and to rely upon open cycle gas turbines to match supply and demand than to adopt any of these options. As a consequence, any large scale investment in wind power will have to be backed up by an equivalent investment in gas-fired open cycle plants. These are quite cheap to build but they operate at relatively low levels of thermal efficiency, so they emit considerably more CO2 per MWh of electricity than combined cycle gas plants.

4. Meeting the UK Government's target for renewable generation in 2020 will require total wind capacity of 36 GW backed up by 13 GW of open cycle gas plants plus large complementary investments in transmission capacity – the Wind Scenario. The same electricity demand could be met from 21.5 GW of combined cycle gas plants with a capital cost of £13 billion – the Gas Scenario. Allowing for the shorter life of wind turbines, the comparative investment outlays would be about £120 billion for the Wind Scenario and a mere £13 for the Gas Scenario.

5. Wind farms have relatively high operating and maintenance costs but they require no fuel. Overall, the net saving in fuel, operating and maintenance costs for the Wind Scenario relative to the Gas Scenario is less than £500 million per year, a very poor return on an additional investment of over £105 billion.

6. Indeed, there is a significant risk that annual CO2 emissions could be greater under the Wind Scenario than the Gas Scenario. The actual

outcome will depend on how far wind power displaces gas generation used for either (a) base load demand, or (b) the middle of the daily demand curve, or (c) demand during peak hours of the day. Because of its intermittency, wind power combined with gas backup will certainly increase CO2 emissions when it displaces gas for base load demand, but it will reduce CO2 emissions when it displaces gas for peak load demand. The results can go either way for the middle of the demand curve according to the operating assumptions that are made.

7. Under the most favourable assumptions for wind power, the Wind Scenario will reduce emissions of CO2 relative to the Gas Scenario by 23 million metric tons in 2020 - 2.8% of the 1990 baseline – at an average cost of £270 per metric ton at 2009 prices. The average cost is far higher than the average price under the EU's Emissions Trading Scheme or the floor carbon prices that have been proposed by the Department of Energy and Climate Change (DECC). If this is typical of the cost of reducing carbon emissions to meet the UK's 2020 target, then the total cost of meeting the target would be £78 billion in 2020, or 4.4% of projected GDP, far higher than the estimates that are usually given.

8. Wind power is an extraordinarily expensive and inefficient way of reducing CO2 emissions when compared with the option of investing in efficient and flexible gas combined cycle plants. Of course, this is not the way in which the case is usually presented. Instead, comparisons are made between wind power and old coal or gas-fired plants. Whatever happens, much of the coal capacity must be scrapped, while older gas plants will operate for fewer hours per year. It is not a matter of old vs new capacity. The correct comparison is between alternative ways of meeting the UK's future demand for electricity for both base and peak load, allowing for the backup necessary to deal with the intermittency of wind power.

1. Introduction

This paper is a companion piece to my paper titled 'The Myth of Green Jobs'. In that paper I examine claims that green energy policies will create substantial employment, concluding that they are misleading in general terms and patently wrong when subjected to careful empirical analysis. One reason why these claims may appeal to lobbyists and others lies in the fact that most forms of renewable energy are capital-intensive, requiring high levels of investment per unit of capacity or energy delivered. Any large investment program will create jobs in construction and other industries, but this has to be funded by lower spending in the rest of the economy; the net impact – holding macroeconomic conditions constant – will be a reduction in the overall level of employment.

In this paper I consider whether the large capital investment required to build wind farms is offset by low operating costs and carbon emissions. I have concentrated on wind power but the conclusions apply even more strongly to solar power. No one, other than the most dedicated lobbyists, believes that solar power will make a substantial contribution to the UK's future energy mix. There is very little concrete information about other, as yet unproven, forms of renewable generation such as tidal barrages or wave power, but there is no reason to believe that they will be more economic than wind power over the next decade.

The costs of traditional forms of renewable energy – primarily hydro power and biomass plants – are better understood. There is very limited scope for new hydro development in the UK and that potential might be best used for pumped storage schemes – taking advantage of the large difference between base and peak load generation costs. Biomass generation plants are just variants of coal-fired generating plants which, in most cases, involve the import of wood chips rather than coal. Since the energy density of wood chips is relatively low, this would be entirely uneconomic unless the plants are heavily subsidised, as is the case under the current Renewables Obligation.

The standard measure used by many public agencies to compare the costs of generating electricity using different technologies is the levelised cost per MWh. As will be explained below, this can be a perfectly adequate measure for making comparisons in a centrally planned electricity system when the issue is whether to build nuclear, coal-fired or gas-fired plants to operate most of the time – i.e. on or close to base load. Unfortunately, this measure may be quite misleading as a basis for making cost comparisons when considering investment decisions for either (a) electricity systems that operate on the basis of market pools (such as the UK), and/or (b) technologies which are inherently intermittent, such as many forms of renewable generation (such as wind power).

A more useful basis of comparison is to ask how much it will cost to meet some portion of the total demand for electricity in a year, taking account of changes in demand over the day or across seasons, as well as intermittency of supply and other factors. It may not be feasible to rely upon one generation technology alone, so usually it is necessary to think in terms of a mixture of types of generation.

It is relatively easy to introduce small amounts of wind power (or other intermittent generation) into a large and diversified electricity system, because the costs of intermittency are largely borne by other operators – particularly older and less efficient gas-fired plants whose operating load can be adjusted fairly easily. The use of levelised costs may be reasonable when thinking about incremental changes of this kind. However, a different set of factors have to be taken into account when the amount of wind generation capacity becomes large relative to minimum levels of electricity demand (base load), which is inevitable under the UK Government's targets for renewable electricity generation.

Sections 2 & 3 explain the key features of electricity systems that affect the comparison of costs of adopting alternative generating technology. Sections 4-6 discuss the operation of policies to promote the use of renewable generation over the recent past and as proposed for the future. Section 7 compares the total costs of achieving a large increase in the share of wind power in the total generation mix against the alternative of meeting the same level of demand using gas combined cycle plants which would be the lowest cost option. Section 8 extends the analysis to consider the reduction in CO2 achieved by relying upon wind power rather than gas-fired generation and, thus, the cost per tonne of CO2 saved by this policy.

I should emphasise that most of the material presented in this paper is standard among electricity economists. The difficulties and costs of combining large amounts of wind power with conventional generation have been understood for a decade. The cost estimates are based on recent studies, but, again, these confirm what should be well known. The reason for writing the paper is that the EU and the UK Government have chosen to play down the basic conclusions of electricity economics in setting targets for renewable energy, perhaps because of an assumption that switching to renewable is a relatively inexpensive way of reducing CO2 emissions. In fact, as the paper shows, this assumption is wrong. When the full impact on the operation of an electricity system is taken into account, setting targets for renewable generation is a rather expensive way of saving CO2. This result is consistent with findings reported by other studies but, again, it has not been widely reported, nor have its implications been incorporated into public policy.

The UK has espoused ambitious targets for reducing CO2 emissions over the next 10-40 years. Others can judge whether these targets make sense as a matter of general public policy. What is certain is that the methods of achieving those targets are both untransparent and, in some cases, absurdly expensive in terms of the costs incurred per tonne of CO2 saved. This should be a matter of concern to anyone on either side of the debate about climate change policy. A policy for reducing CO2 emissions that is very expensive cannot and will not be sustained, but a lot of money and other resources will be wasted in an attempt to deny the inevitable. Hence, Section 9 examines alternative approaches to reducing CO2 emissions in a more transparent and efficient manner, instead of relying upon setting targets for renewable generation, together with similar measures.

2. Comparing like with like for the costs of electricity generation

Consider a classic PR announcement that PQR Renewable Energy is intending to spend £1 billion on an offshore wind farm that will supply 500,000 households with electricity and will create 200 permanent jobs (the example and numbers are fictitious). Does this mean what it says? Two points will illustrate why it does not.

The cost will normally exclude the cost of providing the lines required to transmit the power that is generated from the wind farm to wherever it is used. This is a service provided by National Grid or other companies. Any additional investment that may be required falls outside the ambit of the power project.

Does the statement literally mean that we could ring-fence 500,000 households and supply them with electricity exclusively from the wind farm? Not unless they are willing to put up with interruptions to supply when turbines fail or the wind does not blow or demand for electricity is too high. Since customers generally expect the lights or heating to go on and stay on when it gets dark or cold, someone has to bear the costs of coping with such interruptions.

Electricity systems are designed to meet a demand for electricity that varies by location and by minute, hour and day. They draw upon power generated by power stations that are widely dispersed over the country and which have different technical capabilities to respond to changes in the amount of power that is required. A series of daily load curve describe the pattern of demand for electricity under various weather conditions at different times of day and at different times of the year. In the UK and other countries in NW Europe, the peak demand for electricity tends to occur in the morning and evening periods of cold days in December and January when the length of daylight is short but when people are travelling to or are at work. Other countries have summer peaks because electricity is used for air conditioning. The minimum demand for electricity usually occurs in the early hours of the morning, though seasonal influences on demand for lighting, heating or cooling also play a role. The average minimum demand for electricity over the year is referred to as the annual base load, because it represents the amount of generating capacity that has to run all of the time apart from periods of maintenance. The difference between peak and base load demand varies greatly across countries – annual base load may be as low as 30% or as high as 50% of peak demand. The variation between peak and minimum load on a daily basis is less than this, because the demand curve tends to shift up or down due to seasonal factors. A common pattern is that demand will be less than 70% of peak daily demand for 4-6 hours per day. This may be regarded as the daily base load.

In the absence of ways of storing electricity, fluctuations in demand can be met in two broad ways. Some plants – particularly gas turbines and hydro with storage reservoirs – can be switched on or off at relatively short notice to meet peak demand. Otherwise, it is necessary to rely upon spinning reserve, which consists of plants that are running but with generators that are either disconnected or operating at less than full capacity. Plants whose output can be increased or decreased with some period of notice are known as load-following generators. In most countries nuclear power plants are designed to operate at full capacity or not at all, while various types of gas-fired plants offer much greater flexibility in responding to fluctuations in demand. Large electricity systems have a mixture of plants with different load-following characteristics which can be managed to meet the load curve in an efficient and reliable manner.

It is also important to distinguish between dispatchable and intermittent forms of generation. Dispatchable generators are ones which can be operated to meet demand when it arises, though with varying start-up periods. Nuclear, coal and gas plants all provide dispatchable generation, as do hydro plants if they have storage reservoirs. In contrast, most forms of renewable generation are intermittent, i.e. they are not dispatchable because they can only run when the wind is blowing or the sun is shining, rather than when there is demand for electricity. There are intermediate renewable technologies such as run-of-river hydro plants, tidal barrages or some types of solar thermal plants which may be viewed as partially dispatchable. For example, the fact that tidal power is predictable does not mean that it is dispatchable unless it is accompanied by storage from which water can be released when power is required.

These technical differences are hugely important. Most of the comparisons between the costs of renewable and non-renewable types of generation focus on the cost per MWh based upon an assumption of uniform load factors and a standard discount rate to translate capital and operating costs into a single cost – what is referred to as the "levelised cost per MWh". Unfortunately, in economic terms 1 MWh generated at 9 am on a December morning is simply not the same product as 1 MWh generated at 2 am in the middle of June. Levelised costs are useful for comparing generation technologies that are dispatchable and will be used to meet base load demand. They are profoundly misleading when used for any other comparisons.[1]

A number of arguments are sometimes made to suggest that the intermittency and lack of load-following capability of renewable technologies should not be regarded as a serious constraint on their application. The arguments are of three types: pooling, storage and load shifting.

· Pooling. In the case of wind power the pooling argument is that, while winds may be insufficient to generate power at any one wind farm, on average there will be sufficient wind for substantial generation from a large and dispersed set of wind farms. This is partly correct, but it does not help on a cold December morning with an Arctic high covering most of the UK. In any case, the pooling argument amounts to the statement that we need generating and transmission capacity equal to X times the level of demand that is served by wind power, where the value of X depends upon the typical load factor for wind farms during periods of high or medium demand, i.e. not during the summer.

· Storage. The impact of intermittent generation can be offset if there is sufficient storage. In practice, this means hydro plants with storage reservoirs including pumped storage. It is certainly the case that the marginal value of additional storage is substantial in systems with large amounts of intermittent generation. However, intermittency is only part of the story. The marginal value of storage is also high when there is a large difference between the marginal costs of generation for base load (e.g. nuclear plants) and peak generation (e.g. gas turbines). In the UK and other European countries it has been worth investing in storage where this is possible or acceptable for more than 30 years. The introduction of renewable generation does not change the constraints that limit the amount of storage.

· Load shifting. This is the complement to storage and the arguments are similar. Interruptible supply contracts, time of day pricing, and other arrangements are designed to shift load from peak to non-peak periods. In most cases they achieve little more than limited reductions in peak demand, shaving or spreading the total level of peak demand over a longer period. From an environmental perspective the main effect of interruptible supply contracts is to shift generation from system peaking plants to industrial backup plants with little or no reductions in emissions. Again, there have been strong reasons to encourage load shifting for more than 30 years and many efforts have been made to promote it. The practical reality is that the gains tend to be small while the costs are relatively high. Claims for the

1 The difficulties of ensuring system stability as the proportion of intermittent generation in total generation increases are not a matter of dispute. They have been recognised and analysed by system specialists and energy economists for some time, even among operators with a commitment to wind power – see, for example, E-on Netz [2005]. However, policy makers in many countries have chosen to ignore the implications of intermittency when designing incentives to promote renewable sources of generation. Joskow [2010] demonstrates that this failure leads to large departures from an appropriate framework for assessing and implementing the efficient integration of intermittent and dispatchable sources of generation.

savings made possible by "smart" networks are little more than sales talk that ignores the substantial body of evidence based on actual experience.

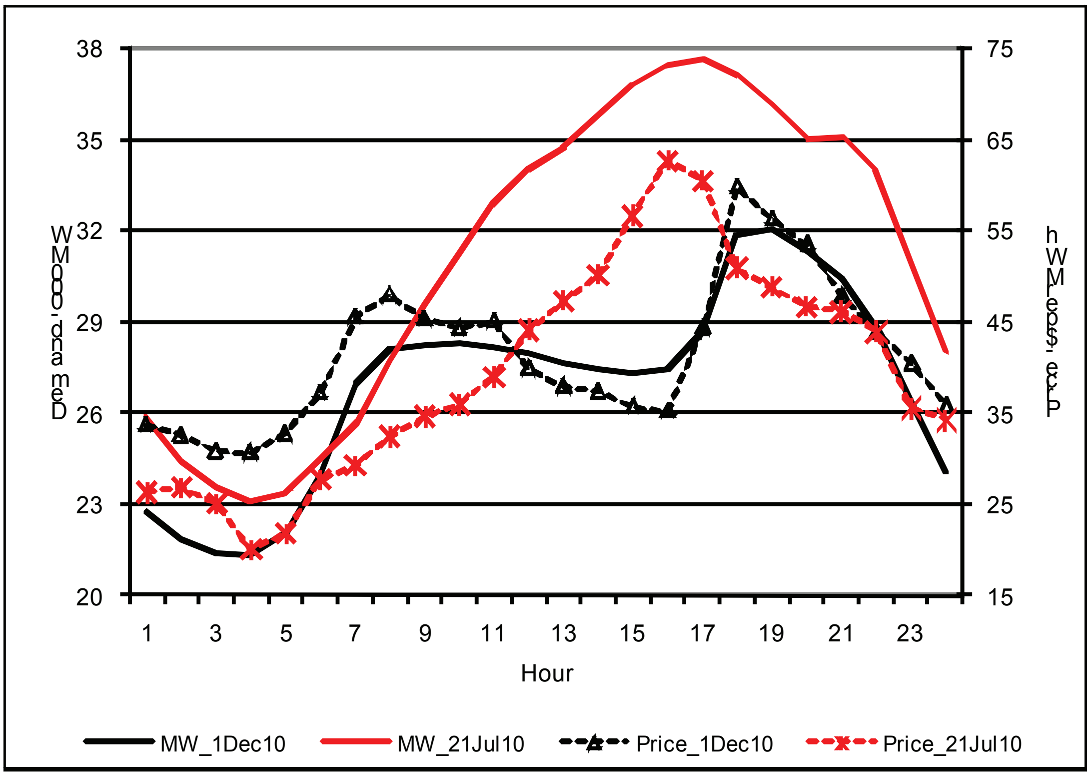
3. Matching supply and demand for electricity

In assessing the costs and consequences of adopting renewable generation technologies, instead of conventional generation it is necessary to understand the way in which electricity systems manage generation to meet fluctuating levels of demand. At any time a portion of installed generating capacity may not be available for dispatch because of breakdowns, periods of maintenance or environmental restrictions. For capacity that is available, the system operator will have a merit order that is based upon the marginal cost of generation - largely based upon fuel costs plus any variable operating and maintenance (O&M) costs that are determined by operating hours – modified by considerations of start-up requirements and transmission constraints. The merit order will mean that plants with low marginal costs – especially nuclear power, large coal plants and run-of-river hydro - will be used to serve base load demand. As demand increases, plants with higher marginal costs will start to generate, which may include combined cycle gas plants (CCGT) and older coal plants. Finally, peak demand will be served by bringing plants with the highest marginal costs, such as open cycle gas turbines (OCGT), into the generation mix. In the UK, storage hydro plants tend to operate at the middle or top (high marginal cost) end of the merit order, since that is how they obtain the highest value out of their stored water resources.

Figure 1 provides an illustration of how demand (left axis) and market prices (right axis) fluctuate over a period of a day. It is based on day-ahead forecasts of demand and the day-ahead market prices of power for two Wednesdays - 1st December 2010 (winter) and 21st July 2010 (summer) – produced by the system operator for California. Average demand is higher in summer than in winter, but more importantly the differences between the maximum and minimum values for both demand and prices are considerably larger in summer than in winter. The market prices broadly track the forecasts of system demand as plants with higher operating costs have to be brought into service to meet higher demand.

The daily and seasonal pattern of demand and prices has an important consequence for investment in new generation. In a competitive market – or an integrated electricity system run to minimise costs – the market value of electricity in any time period will be close to the marginal operating cost (fuel and variable O&M) of the unit which is highest in the merit order and which must run in order to ensure that supply balances demand for electricity. However, generating plants will only cover their fixed capital and O&M costs if they earn a margin over their marginal operating costs. In practice, this means that base load plants can only contribute to their fixed costs while they operate during periods when higher marginal cost plants are setting the market price. For example, a nuclear plant has to cover its fixed costs from

Figure 1 – Day-ahead forecast of system demand and prices for California



Source: California ISO (www.casio.com). System demand for California, prices for SCE (Los Angeles).

its operations outside periods of minimum demand. This fact undermines the relevance of levelised cost calculations, which assume, in effect, that capital costs are recovered uniformly over all hours of operation. As I will explain, it is particularly important for intermittent but capital-intensive types of generation.

A simplified merit order for dispatchable generation technologies is from low to high marginal cost: (a) geothermal; (b) nuclear; (c) hydro; (d) advanced coal; (e) conventional coal; (f) biomass; (g) gas combined cycle; (h) gas turbine; and (i) pumped storage hydro. Sources of intermittent renewable generation have low marginal costs and high capital costs, so that wind and solar power will be used whenever they are available. As the share of renewable energy in total capacity increases, market prices will tend to be low when intermittent generators are operating and they will tend to be high when they are not operating. This is illustrated by the California market. For climatic reasons, wind generation in California has a distinctive time profile – it is lowest in the middle of the day and highest in the late evening and early morning. Hence, wind generators receive a lower average price per MWh generated than the average for all generation.

Even without the distinctive time profile of wind generation in California, the result is general. In many important regions in the US and Canada there is a negative correlation between the amount of wind generation and peak demand. As an illustration, the capacity factor for wind generation during peak hours in New York State was less than 18% for 2007-09, well below a target value of 30-35% over the whole year. In addition to any physical relationship of this kind, an efficient system for dispatching power will mean that the average revenue per MWh of power from intermittent generators is likely to be less than the equivalent figure for dispatchable generators. As the capacity of wind generators increases, market prices will tend to be low when the wind is blowing and high when it is not, holding other factors constant. This means that the average revenue – and the margin for fixed costs – per MWh of wind generation will fall relative to the system average revenue. Since the capital costs of wind generation are high and already require subsidies, adding more wind generation will simply increase the magnitude of the subsidies required to underpin investment in wind generation.

In fact, the full consequences of promoting wind generation are yet more complicated and self-defeating. By reducing revenues for base load and mid-merit generation when wind is available, wind generation reduces the incentive to invest in other sources of base load generation – particularly nuclear power or coal with carbon capture & storage (CCS). Thus, investment in wind power will tend, in the main, to displace investment in nuclear power rather than gas plants. Indeed, with more intermittent wind power and less dispatchable nuclear power it will be necessary to rely more upon either coal or - more likely - gas plants to supply both base load power when wind is not available plus mid-merit and peak generation at all times. The irony is that the promotion of intermittent types of renewable generation may increase rather than decrease total CO2 emissions relative to what they would have been if markets had been encouraged to reduce CO2 emissions in the most cost-effective manner – see section 6 below.

The actual effects of increasing the share of wind generation in total generation capacity will depend upon whether the government attempts to "fix" the market to produce outcomes that it considers desirable rather than those which would result from the operation of an efficient market. However, it is well documented that extra wind generation may be a very expensive way of reducing CO2 emissions when the impact of wind power on system operation is taken in account. (Joskow [2010] quotes a figure of $300 per metric ton of CO2 for New England. This assumes that the substitution margin is between wind and gas combined cycle, whereas the key margin in the UK is between wind and nuclear power.)

4. The Renewables Obligation

The UK's current incentives for reducing CO2 emissions and promoting renewable generation – designed to meet targets known as the Renewables Obligation (RO) - are singularly perverse when viewed from a system perspective. The basic idea is that electricity suppliers are required to hold Renewables Obligation Certificates (ROCs) equivalent to X% of the total amount of electricity which they supply in a year or pay a fixed penalty of £P per unit of any shortfall. The values of X & P have been increasing over time. Electricity suppliers can purchase electricity from renewable generators or they can buy ROCs in the market. The effect is that electricity from renewable generation will command a premium of £p per unit over electricity from non-renewable generation subject to $p \leq P$. In principle, this is an elegant variant on emission trading designed to promote renewable energy. The reality is rather different.

The operation of the market in ROCs means that a wind generator faces a negative marginal cost of operation when the wind is blowing. Similarly, other generators that qualify for ROCs face lower marginal costs of operation than those which do not qualify for ROCs, even if they have similar levels of CO2 emissions. Hence, the merit order is based on eligibility for ROCs rather than real economic costs including the cost of CO2 emissions.

The mechanism is made even worse by the fact that the allocation of ROCs is simply arbitrary interference in the market – there can be no justification on environmental grounds for awarding more ROCs (2 per MWh) for offshore wind generation than for onshore wind generation (1 per MWh). Similarly, the ROCs do not reflect the relative impacts of different greenhouse gases, otherwise much higher weight would be given to power generated from landfill or sewage gas – which reduces direct emissions of methane, a much more potent greenhouse gas than CO2.

Every energy economist knows that, under present rules, the Renewables Obligation is a scandalous boondoggle.[2] Unfortunately, it goes beyond an unwarranted transfer from electricity users to a privileged group of producers. Consider the situation if the RO is entirely met out of wind generation with no distinction between onshore and offshore wind. To meet an RO target for 2010-11 of 11.1% of total generation would require about 17,800 MW of wind capacity at an average load factor of 27% (the average for UK wind farms in 2009-10). The maximum demand in 2009-10 was about 60,300 MW, so wind would account for almost 30% of peak demand, or more than 80% of total base load, if it was available. But one cannot run either nuclear or large coal plants on the basis that they have to be switched off or on depending on whether the wind is blowing. The situation would be even worse if the RO target is raised to 15% since this would require wind capacity of 24,000 MW, which exceeds base load.

The truth is that meeting the RO by intermittent sources of generation ensures that all conventional base load plants in the UK – nuclear or coal – will be uneconomic in future. It would be madness for an investor to build new

2 Webster's College Dictionary - the standard US dictionary - offers the following definitions of a boondoggle: "(1) work of little of no value done merely to keep or look busy; (2) a project funded by the federal government out of political favouritism that is of no real value to the community or the nation".

nuclear plants under such conditions. The only way of ensuring the reliability of electricity supplies will be a huge expansion of combined and open cycle gas plants. Yet, the previous Secretary of State for Energy and Climate Change has said that the government wishes to avoid a new "dash for gas". In reality, any such outcome will be the direct result of the incoherence of the government's own policies.

It should be emphasised that the problem lies with the Renewables Obligation, not with a more rational scheme to price CO2 and other greenhouse gases. It is perfectly possible to reduce CO2 emissions while maintaining system stability and reliability of electricity supply. What is not possible is to meet these goals at reasonable cost, while simultaneously insisting that intermittent sources of generation expand to 40% or 50% of total capacity.

There is a way of avoiding the impact of the RO on base load generation – storage. One variant of this is that the level of base load demand will be increased by night-time charging of electric vehicles. This is technological fantasy for the next 10 or 20 years. In any case it does not address the intermittency problem, unless electric vehicles are actually hybrids that can operate on petrol alone when the wind doesn't blow.

A variant of the electric vehicle story is long distance transmission of wind power across Europe, on the grounds that the wind will blow somewhere at all times. Again, this is technological fantasy which ignores demand patterns, meteorology and economics. Investigations of long distance DC or AC transmission of hydro power have repeatedly shown that it is more expensive than the alternative of transporting fuels (gas by pipeline or coal by rail) plus local generation. Schemes for a huge European super-grid are political constructs with almost no basis in economic reality. For the UK, reliance upon gas imported by pipeline or as LNG (both of which can be stored) combined with dispatchable gas-fired power plants will be far cheaper than massive North Sea interconnectors.

The only viable, but politically unrealistic, way of storing intermittent power generation is to build pumped storage schemes in every Highland valley. If onshore wind farms and the associated transmission lines are unpopular, how much more resistance would a commitment to build new pumped storage in every suitable valley generate?[3] Most would have to be in Scotland since locations for large reservoirs with a height difference of 100+ metres are scarce in the rest of the UK.

3 Scottish & Southern Electricity has proposed a new scheme for two plants in the Great Glen in Scotland but it remains unclear how vocal the objections will be. The proposed capacity is said to be up to 1,200 MW and the project announcement describes the reservoirs as large. Overall, the scheme seems to be designed as peaking capacity (an average of 2-3 hours per day) rather than as a significant contribution to offsetting the intermittency of wind generation. This illustrates the difficulty of using hydro storage to address large scale intermittent generation.

5. Proposals for Feed-in-Tariffs

The UK government has recognised that the Renewables Obligation and the associated market in ROCs will not support the investment in renewable generation, nuclear power and coal generation with CCS that it considers to be essential for the UK's future needs. In its recent White Power dealing with proposals for reforming the electricity market in the UK, the government has proposed new market contracts designed to promote investment in low carbon forms of electricity generation. The proposed arrangements rely upon variants of guaranteed prices – Feed-in-Tariffs – under which the gross revenue of a generator is determined by the guaranteed price and the amount of electricity actually supplied to the grid. Slightly different mechanisms are proposed for (a) intermittent types of generation including wind power, and (b) base load plants including nuclear power, biomass plants and coal plants with CCS, but the key element in both is a guaranteed price for powerdelivered to the grid. The new arrangements will replace the Renewables Obligation once the necessary legislation has been passed and implemented.

The proposed contracts differ from the classic combination of capacity or availability payments plus operating payments per unit of electricity generated that is standard under many power purchase agreements outside the UK – see below. Hence, it is worth considering whether the proposals are compatible with meeting the load curve at minimum cost to electricity consumers. In examining this I will focus on the essential characteristic of the contracts – viz. reliance upon a guaranteed price. Many of the precise details are a consequence of an attempt to reconcile the new contracts with a continuation of existing market arrangements for non-privileged forms of generation.

There is one very striking feature of the proposed arrangements that is contained in a study of the cost of capital undertaken by CEPA for DECC.[4] CEPA conclude that the cost of capital for established wind power would be in the range 8.4-9.6%, with figures at the top end of this range for offshore wind because of development risks. This is 0-0.8 percentage points below their estimates of the cost of capital for wind power under the Renewables Obligation. But, much more important is the fact that the cost of capital for guaranteed price contracts is far higher than the typical range of 5.5-6.5% for regulated energy and water networks in the UK. This is a huge premium for a very capital intensive form of generation and it is inconceivable that such a premium would be necessary under a capacity plus operating payment structure, assuming similar contract terms.

In fact, CEPA's estimate of the cost of capital may be too low, for a reason that illustrates the potential pitfalls in the proposed contracts. Structurally, they are very similar to Private Finance Initiatives (PFI) contracts unless prices

4 The study was published separately at the same time as the White Paper and is available on DECC's website.

are guaranteed for a short period relative to the economic life of the assets. Both involve substantial initial risk associated with construction which is compensated by a (relatively) stable return over the remainder of the contract. This permits sponsors to re-finance projects after construction and make what may appear to be an unwarranted capital gain. In the case of PFI contracts this has led to political pressure on the Treasury to claw back 'excessive' returns. It is very likely that similar complaints will be made about guaranteed price contracts and sponsors may have reasonable concerns about unfavourable changes in contract terms if they wish to re-finance or sell on their investments. Such concerns will increase the effective cost of capital and/or shorten the period over which sponsors expect to amortise their investment.

The cost of capital is crucial in this context because it underlies many of the trade-offs that have to be made in reducing CO2 emissions by relying on renewable energy. Indeed, it is simple economic nonsense to set targets for CO2 emissions from electricity generation that can only be justified on the basis of a relatively low discount rate if the cost of capital required to achieve those targets is much higher. A minimal requirement for any economic assessment of targets for reducing CO2 emissions is that the same discount rate should be applied to both the costs and the benefits of meeting the targets, i.e. any investment in measures to reduce CO2 emissions as well as the effects of mitigating climate change.

If we assume the same cost of capital for all contractual arrangements, the discounted present value of total revenues should be identical under contracts offering either (a) a guaranteed price or (b) capacity plus operating payments, provided there is competitive bidding for contracts and other contract terms such as length and expected operating hours are identical. But this is where the comparison breaks down.

In recent months there has been some adverse comment on the fact that wind farms in Scotland have been paid compensation by National Grid because transmission constraints meant that their potential output could not be dispatched. This is only a small example of what is likely to happen in future. If large investments in nuclear power, coal with CCS and wind generation are contracted under the arrangements that have been proposed, then it will be the rule rather than exception that wind plants will receive payments when they could be generating but are not required for technical or demand reasons.

As highlighted earlier, the key problem with wind power arises when either the installed capacity of wind plus base load plant exceeds base load demand or there are transmission constraints. In either case a portion of wind and/or base load generation has to be constrained not to operate. Under the guaranteed tariff arrangements in the White Paper, wind plants will receive the guaranteed price if they bid to supply electricity to the grid but are constrained out.[5] A good strategy for wind generators would be to

5 In Annex B of the White Paper this is described as a problem of 'negative prices', but in fact it may apply even when

bid to supply electricity at a low price whenever they expect constraints to apply, whether or not they have sufficient wind. If they are constrained, then they receive the guaranteed price. If they are dispatched but do not have sufficient wind to meet the dispatch, then they buy in gas-fired generation from their own or contracted backup sources. Under the arrangements that have been proposed, there is a risk associated with divergence in prices between the day-ahead and the spot (30 min-ahead) market, but this can be managed by a generator with a portfolio of different types of generation.[6] Hence, the strategy offers the prospect of making occasional but substantial profits in exchange for modest and controllable risks. This will encourage additional investment in wind generation, which may meet the government's targets for renewable generation but will simply exacerbate the costs of intermittency and constrained generation capacity that have to be borne by all customers.

This is a game that cannot be sustained indefinitely. Any sensible investor will expect the contracts to be terminated or rewritten at some future point, which brings us back to the cost of capital. Offering guaranteed prices for privileged sources of generation, via a *contract for differences* mechanism, is an attempt to preserve the electricity market. However, they are effective only because they are costly and economically inefficient, so no one can be confident about how long such generation will benefit from subsidised prices.[7] The adoption of an inefficient and costly mechanism for supporting low carbon sources of generation pushes up the cost of capital and further increases the burden on customers implied by targets to promote renewable energy as well as low carbon generation.

6. Alternative contractual arrangements

Offering guaranteed prices for certain types of generation is far from the most efficient way of ensuring investment in low carbon generation. There is little doubt that, starting from scratch, the least expensive option would be to offer power purchase agreements (PPAs) that guarantee a fixed payment for capacity availability plus an operating payment to cover O&M costs directly linked to hours of operation. The overall cost of such contracts can be (relatively) low, because the contract is consistent with efficient management of dispatch and makes economic sense. Thus, provided that the regulatory framework and contracting party are reliable, there is no reason

market prices are positive.

6 The proposed arrangements will encourage wind generators to sell power in the day-ahead market. If they are dispatched but are unable to deliver power from qualified wind plants, they will receive the day-ahead price – not the guaranteed price – and would have to buy power in the spot market to meet their commitment. A portfolio generator can control this risk by changing the way in which it sells power from, for example, its gas-fired plants.

7 Note that this is not primarily an issue of whether the contracts or regulatory framework can be relied upon, though regulatory risk in the UK is certainly not zero. The problem is that it makes little sense for the government to agree to contracts that last for the full life of new plant – 25 or 40 years. Even if investors are confident that contracts will be honoured, they face large residual uncertainty about the way in which the electricity market will operate after the guaranteed price contracts come to an end

to require a cost of capital that is significantly higher than any other regulated rate of return. The difficulty, of course, is that offering such contracts on a large scale cannot be reconciled with the type of electricity market that has developed over the last 20 years.

Contracts of this type are not unusual in electricity markets dominated by a single buyer. They are particularly common when the buyer is concerned to ensure the availability of sufficient capacity in the face of uncertainty about how much it will be used in future. As an illustration, a country that is able to rely upon hydro power generation in normal years may wish to ensure that gas plants as backup for years in which there is insufficient water. Another element of the White Paper is a consultation on whether such contracts should be offered in the UK so as to ensure sufficient investment in open cycle gas plants as backup for intermittent wind power.

There is a common thread that underpins all of these proposals. Over the last two decades the UK has developed elaborate trading arrangements by which the dispatch of generation is largely determined by bids made by generators in various markets. Both buyers and sellers of power can then stabilise the average price that they pay or receive by entering into contracts for differences which are designed to offset the difference between day-to-day (or other market prices) and an agreed price over the length of the contract. The RO provides incentives for renewable generators on top of the market price. These arrangements are efficient and have ensured relatively low market prices for power in the UK, especially when there is surplus generating capacity.

The difficulty for government policy is that all forms of capital-intensive generation, including wind and nuclear power, are uneconomic under this market structure unless they are heavily subsidised. This is because the market price is essentially driven by gas prices and the costs of running gas plants with low capital costs and (relatively) high operating costs. Long term contracts proved disastrous for several generators in the early 2000s, so both buyers and sellers are reluctant to enter into such contracts now. On the other hand, without long term sales contracts, the risks of investing in capital-intensive forms of generation imply a very high cost of capital.

The essence of the government's proposals is that it will enter the market – as a single buyer – to offer long term contracts for privileged forms of generation. All of the elaborate detail in the White Paper is designed to provide a way of reconciling two fundamentally different models of market operation while retaining the existing manner in which dispatch is organised. There can be little doubt that the attempt is doomed to fail. Either (a) the government will, figuratively, run out of money – i.e. the public will be unwilling to pay the increasingly large costs of funding expensive forms of generation – or (b) the government as single buyer will gradually become the dominant contracting party in the market.

Many economists advise against reliance upon a single buyer model for electricity markets. Their reasons are very similar to those which commend this arrangement to politicians – the likelihood of entering into long term contracts that may prove to be very expensive and inflexible, just like many PFI deals. Of course, if you are convinced that market signals are "wrong" and that investment in different forms of generation is essential, then the ability of a single buyer to intervene in the market is very attractive, especially if the costs of such intervention are borne by a diffuse and poorly informed set of consumers. It is a classic example of rent-seeking by which special interests – including promoters of renewable energy – benefit at the expense of the whole population.

However, given the government's goal of promoting low carbon generation, are the policies an efficient and effective way of achieving that goal? The answer has to be no. If single buyer intervention is seen as essential, at a minimum the contracts should be designed to ensure that investments incur the lowest cost of capital and that plant is operated and dispatched as efficiently as possible. This implies a combination of classic PPAs together with economic dispatch managed by the National Grid. Of course, this is a complete change from existing market arrangements, but it is the logical outcome of the government's proposals without incurring the much larger costs associated with approaching this end point via an indirect route.

I do not wish to imply that it would be easy to implement a single buyer model as a way of stimulating investment in large carbon generation. It is worth highlighting two major issues:

· Dispatch rules must be designed to minimise the marginal cost of meeting fluctuating levels of demand allowing for considerations such as start-up and shut-down costs, intermittency of renewable generation, scope for time shifting via storage reservoirs, etc. The difficulty of reconciling the dispatch of intermittent sources of renewable generation with relatively inflexible forms of generation with low marginal cost and low carbon emissions such as nuclear power or coal with CCS is not altered by the financial arrangements designed to reduce the cost of capital.

· Electricity customers face a prospect of electricity costs that are dominated by fixed capacity payments rather than usage-related costs. This may lead to a variety of difficulties depending upon how the government decides to pass on the capacity payments to users. Two-part tariffs to recover fixed network, billing and other expenses are contentious and, apparently, not understood by most consumers, yet recovering capacity payments by increasing tariffs per MWh will undermine attempts to introduce time of day or peak load tariffs.

The design of the contracts is very important. A combination of capacity and operating payments is attractive to investors but it is very unlikely that a single buyer would commit to such a structure for the full life of a plant.

Many PPAs have a life of 15-20 years, which gives flexibility to the buyer but leaves the investor facing substantial risk after the expiry of the contract. As a consequence, most investors will plan to recover most or all of capital costs over the life of the PPA, so that the effective cost of capital including amortisation of the investment may be rather high for long-lived assets. If investors have limited faith in the commitments embedded in PPAs – not entirely unreasonable in the light of the fractious history of PFI contracts – they will make their decisions on the basis of a relatively high rate of discount.

Consider a 1000 MW nuclear power plant with an economic life of 50 years. The capacity payment under a very rigid PPA lasting 40 years with a discount rate of 6% in real terms would be about £210 million per year at constant prices, while for a more flexible PPA lasting 20 years with a discount rate of 10% would be about £335 million per year. Both figures are large relative to the equivalent capacity payment for a gas CCGT of about £72 million per year, but they illustrate the substantial cost of flexibility. It may be difficult to persuade electricity customers to accept the cost of the capacity payments required to meet the government's targets under relatively flexible contracts. On the other hand, making a commitment for 40 years might be even more contentious since priorities and technologies can easily change over one or two decades.

These problems arise even more strongly when dealing with guaranteed price contracts. The basic cost of capital is higher and the incentives for gaming the market are larger, so that the costs to electricity users of ensuring efficient dispatch and contract flexibility are even greater than for conventional PPAs.

It is also crucial not to lose sight of the ultimate goals of economic, environmental and energy policies. At times it is easy to gain the impression that the approach of the UK government starts from the thought: Renewable energy is the solution, now what is the problem? Our economic life and social arrangements depend upon reliable and efficient access to electricity. At the same time the government is committed, for whatever reasons, to reducing emissions of greenhouse gases. Wind or nuclear power may have a role to play in meeting these goals. But any assessment of that role should not start by asking how to ensure that investments in low carbon generation take place. What matters is whether any particular form of generation meets two key requirements: (a) to generate electricity in a reliable and efficient manner, and (b) to reduce greenhouse gas emissions at a reasonable marginal cost per tonne of CO2 saved. I will examine these questions in the remainder of this paper.

7. Cost comparisons

Where, then, does this leave like for like comparisons between renewable and conventional forms of generation with respect to employment, etc? The answer depends upon how the question is formulated. Since the issue is policy over the next decade, I will examine what will be required to meet electricity demand in 2020 on the basis of the government's targets for renewable generation. Under the most recent set of projections published by DECC, final demand for electricity in 2020 is expected to be 376,000 GWh in their "Central Price" scenario, of which 30.9%, or 115,000 GWh, is supplied by renewables - the equivalent figure for 2010 was 327,700 GWh. Being generous, I will assume that 25% of the total comes from intermittent sources (excluding hydro, biomass, landfill gas, etc). There is no projection of peak or base load demand, but the peak is likely to be about 15% higher than in 2009, or about 70 GW, while base load may be assumed to be 35% of peak demand, or about 25 GW.

With current load factors of 26% for onshore wind and 28% for offshore wind, the wind component of total demand would require about 41 GW of onshore wind capacity or 38 GW of offshore wind capacity. In practice, onshore load factors are likely to decline as the best sites are used, while offshore load factors may rise as wind farms are located in deeper water. Being very generous, one might assume that the theoretical load factor for offshore wind will increase to 33%.[8] This would reduce the amount of installed wind capacity required to meet the renewables target to 33 GW. If the same amount of electricity were supplied by new gas combined cycle plants, the amount of installed capacity would be about 13 GW. Allowing for projected differences in unit capital costs, the gas plants would involve a total investment of about £8 billion, while the offshore wind plants would cost about £87 billion. This is without making any allowance for the capital cost of the additional transmission capacity that would be required. Assuming that these would be high voltage DC lines, the cost is likely to be at least £1.0-1.5 billion per 5 GW of capacity or £7-10 billion for the full amount of wind power. Note that the capital cost of transmission alone is likely to exceed the total capital cost for gas plants.

But this is not the end of the story. There are two other constraints that must be taken into account when looking at the role of wind power in the electricity system as a whole.

· The installed wind capacity required to meet the 25% target exceeds base load by a considerable margin. There will be times when wind generation would not be dispatched even though it is available. Thus, the actual load factors will be lower than the values used above because of dispatch considerations. The magnitude of the reduction will depend on the amount of non-wind base load capacity (required for system stability) and the pattern of potential wind generation in relation to peak and base load demand. No-one really knows how large the gap between potential and actual load factors is likely to be, but it will get larger as the amount of installed wind

8 In a study for DECC, Mott Macdonald [2010] use load factors of 38-45% for R3 offshore wind (in the deepest water). This is far above the average load factors for offshore wind anywhere in the world and reflects endemic over-optimism about the prospects for renewable technologies.

capacity increases. This creates a vicious circle under which installing additional capacity to meet the renewable generation target reduces the actual load factor and requires yet more capacity. It is not unreasonable to assume that the actual load factor for offshore wind will turn out to be little different from today's 28%. In that case the total capital cost of the generating capacity and transmission required will be more than £110 billion or about 14 times the amount for gas plants.

· How is the intermittency issue to be dealt with during periods of peak demand? DECC's projections imply the following story in 2020 for dispatchable sources of generation. Nuclear power and coal with carbon capture operate on or close to base load. Coal plants that are only permitted to operate for a relatively small number of hours per year are retired and the remaining coal plants operate in the middle of the merit order with an average load factor of 53%. Existing and new gas plants are shifted from the middle of the merit order to peak operation – the average load factor for gas plants falls from 57% to 31%.

As a matter of system economics the story makes no sense. The total amount of capacity (including wind) assumed to operate on base load exceeds base load demand by nearly 60%. Either (a) the load factor for wind generation will fall even further, or (b) nuclear plants and coal plants with CCS will have to operate in a way they are not designed for, which will be very expensive. Coal plants without CCS will operate for long periods on spinning reserve, producing a lot of CO_2 and no electricity. Finally, investors in existing gas combined cycle plants will find that they are expected to operate as peaking plants and are unable to recover their capital costs. This will ensure that no one will invest in new gas capacity and the lights will go off when the wind isn't blowing.

The best way of thinking about like with like comparisons with a large amount of intermittent power is to ask how a stand-alone system could be designed to meet 30% of total electricity demand in 2020 based upon an installed wind capacity of 36 GW.[9] The key constraint would be to ensure sufficient dispatchable capacity to meet peak demand plus a conventional reserve margin of 15% - a total of 25 GW. This is the amount of gas backup capacity that would be required in the worst case – i.e. if the wind does not blow at all during a period of peak demand. It may be more reasonable to assume that at least 33% of wind capacity is available in the worst scenario (matching the load factor for offshore wind). In that case the amount of gas backup capacity required would be about 13 GW. This would operate with a very low load factor (about 17%) so that it would only be economic to use open cycle gas turbines rather than combined cycle plants.

Hence, the true like for like comparison between investment in conventional (dispatchable) power plants and intermittent renewable generation to meet

9 The assumptions are based upon 94,000 GWh from wind generation with an average load factor of 30% and18,800 GWh from gas OCGT. The comparison with gas CCGT assumes an average load factor of 60%

the government's renewable generation target would be as follows:

Scenario A: 21.5 GW of conventional generation capacity with a cost of about £13 billion for gas CCGT.[10]

Scenario B: 36 GW of offshore and onshore wind capacity with a cost of £100 billion for generation and transmission plus 13 GW of backup gas OCGT capacity with a cost of about £5 billion. It is also necessary to allow for the fact that wind turbines have a significantly shorter operating life than gas plants, which increases the annual capital cost by about 15%. Hence, the full capital cost of this scenario would amount to about £120 billion.

In round numbers the capital cost of Scenario B that relies upon renewable generation will be 9-10 times the capital cost of Scenario A. On top of this we must allow for annual O&M costs, which are particularly high for offshore wind plants. The total fixed and variable O&M costs, excluding fuel, for Scenario B would be about £3 billion per year as compared with about £0.6 billion per year for Scenario A.

Of course, the higher capital and non-fuel operating costs for the renewable Scenario B may be offset by a reduction in fuel costs, but this will not be as large a gain as might be expected. There are two considerations that matter:

· OCGT plants are much less efficient than CCGT plants, i.e. they use up to twice as much gas per MWh of electricity that is generated.

· Gas is a fuel that is subject to peaks and troughs in demand. The average price of gas consumed during periods of peak demand, not just for electricity generation but also residential and other heating, is much higher than during periods of low demand. The standard levelised cost calculations are based upon take-or-pay contracts which assume a more or less constant level of consumption over the year, i.e. for base load generation. That is not the way in which gas plants used as backup to wind generation would operate. Instead, they will have to buy most of their gas at times of peak demand and will pay prices that are much higher than the average price for Scenario A.

The consequence of these two factors is that, notwithstanding the lower load factor for gas plant in Scenario B, the difference in fuel costs between the two scenarios may be relatively small. Using DECC's central price projection of £7.40 per GJ and assuming a 20% premium for intermittent demand, the fuel cost for Scenario A is £2.9 billion per year higher than for Scenario B.[11] Thus, a huge capital investment in renewable energy has the net effect

10 The 21.5 GW is calculated to match the total generation of 112.8 GWh in the renewable scenario at an average load factor of 60%, notionally added to the existing system in 2020 in place of the combination of wind and backup gas capacity. This would give a reserve margin of over 30% over peak demand, so it is far more conservative than is strictly necessary.

11 DECC's projections for gas prices are much higher than current market prices or most projections for international markets up to 2030. These tend to be less than $8 per million BTU which translates to about £4.75 per GJ. At this lower

of reducing operating and fuel costs by little more than £500 million per year under assumptions that are deliberately favourable to wind power.

Under the most favourable assumptions, Scenario B will reduce CO2 emissions by about 23 million metric tons in 2020, equivalent to 2.8% of the UK's total greenhouse emissions in 1990 (the baseline for the government's targets). In practice, the saving is likely to be significantly less than this. With a relatively low discount rate of 5%, the net cost including depreciation of investment is about £270 per metric ton of CO2. By any standards this is an extraordinarily expensive and relatively ineffective way of reducing emissions of greenhouse gases.

To get the figures in perspective the UK's total greenhouse gas emissions in 1990 were 774 million metric tons of CO2-equivalent. This had fallen to 628 million metric tons in 2008 – largely due to the closure of the coal industry. The official target under the Climate Change Act 2008 is for a 34% reduction relative to 1990 by 2020. Allowing for economic growth, the effective reduction required by 2020 should be about 290 million metric tons per year. At an average cost of £270 per metric tons of CO2 the total cost of meeting that target will be about £78 billion per year, or about 4.4% of projected GDP in 2020 (all at 2009 prices). And that is only a starting point, because there is a proposal to reduce total emissions to 60% of the 1990 level by 2030 which would required a further effective reduction of 310 million metric tons per year at a marginal cost that is likely to increase sharply.

The UK Government appears to believe that shifting from fossil fuels to renewable energy is a (relatively) low cost way of reducing carbon emissions. Many specialists consider that this shift is likely to be most cost-effective for electricity and rather less so in sectors such as transport. Nonetheless, the analysis of power generation presented here suggests that relying upon renewable sources of power generation instead of gas will make, at best, only a small contribution to meeting targets for reducing emissions of greenhouse gases at a rather high cost. If this is the best option available, then the whole approach needs to be reconsidered.

8. Does wind generation reduce CO2 emissions?

The answer to the question posed in the title of this section may appear to be obvious. Surely, increasing the amount of electricity generated from wind farms must reduce the total amount of CO2 emitted by the electricity sector. Yet, as is so often the case, the correct answer depends upon how the question is interpreted. If the question refers quite specifically to the effect of replacing 1 MWh of electricity currently generated from a coal or gas power plant by wind power, *holding everything else constant*, then the answer is yes. But, as earlier sections illustrate, this is not a helpful way of interpreting

price, the difference in fuel costs would amount to £1.85 billion per year, or less than the difference in O&M costs.

the question when thinking about the policy issue of whether the promotion of renewable energy has economic and/or environmental benefits. The fact that most politicians and civil servants appear to interpret the question in its narrow sense is unfortunate, but it reflects the very limited understanding of electricity systems that characterises most policymaking in this area.

An alternative answer, based on system considerations, runs as follows. Wind power is intermittent and requires backup sources of power – either gas or coal. These backup sources achieve much lower levels of thermal efficiency – defined as the proportion of the energy content of the fuel that is converted into electricity - than conventional power plants using the same fuel which operate all or most of the time.[12] The loss in thermal efficiency is even greater if the backup sources have to run for extended periods as spinning reserve, using fuel but not delivering power to the grid, in order to smooth fluctuations in either demand or supply from wind sources. Hence, the loss in thermal efficiency when plants run as backup sources may outweigh the reduction in the total amount of power generated from fossil fuels when wind generation is added to the system. Under these circumstances, the correct answer to the question depends upon the precise numbers – i.e. the balance between the reduction in CO2 emissions due to wind generation vs the increase in CO2 emissions due to the shift from higher to lower efficiency plants for the remaining generation from fossil fuels. Assuming that the answer is yes is unwarranted since it depends on specific circumstances rather than assertion. As important, this argument tells us that any reduction in CO2 emissions due to additional wind generation will certainly be much lower than the headline figures quoted by lobbyists for renewable energy.

To quantify the issue it is necessary to be more precise about the elements that enter into any calculation. What follows is a primer on these elements, designed to clarify where they come from and what they mean.

Availability, capacity, in-feed and load factors. When discussing any form of generation there are three things that have to be distinguished. How many hours per year will the plant be able to contribute electricity to the grid? How many hours per year will the plant run, whether or not it supplies electricity to the grid? And, how many hours per year will the plant actually feed electricity into the grid? The answers differ substantially across types of generation, but the differences are often ignored in casual discussion.

Availability refers to the proportion of hours in a year that a plant is capable of producing electricity.[13] For fossil fuel plants this depends upon downtime due to periods of maintenance and interruptions due to various failures.

12 The whole issue is rather more complicated if the backup plants are designed as combined heat and power units, with the capacity to switch from heat to power as required for power system stability. This can work successfully on a small scale but it is not a viable solution for large electricity systems.

13 There is a technical meaning of (economic) availability used by many system operators which refers to periods when the plant operator has declared that a plant is "available" to dispatch electricity into the grid given an appropriate period of notice. This may be influenced by economic factors. For example the operator of a coal plant that is only permitted to operate 2000 hours per year might not wish to generate electricity – and, thus, not declare the plant as being available for dispatch - if it expects that it could earn a higher margin by operating at some other time. For this discussion I have focused on physical availability without regard to the effect of such considerations.

Sometimes a plant may be available to operate at reduced capacity, but most plant operators will wish to avoid this situation if at all possible. When a fossil fuel plant is not available it will not be using fuel. For wind plants, availability is largely determined by the amount of wind at the places where wind farms are located. Sometimes the wind may be only sufficient to permit a turbine to operate at reduced capacity or it may be too high for safe operation. Maintenance and breakdowns are also relevant, but the main influence on availability is wind – or sunlight for solar generation.

Availability is important primarily at periods of peak demand because that is when the balance between demand and potential generation capacity is tightest. Over the course of a year, a modern fossil fuel plant may not be available for 2-4 weeks for maintenance and breakdowns, as operators have a strong incentive to minimise periods of non-availability, especially when demand and prices are highest.

The availability factors for individual wind farms vary greatly with location, design and other factors. Manufacturers cite estimats of non-availability due to breakdowns, maintenance, etc. of 2-5% of annual hours. This may be substantially higher for offshore wind farms where access by ship may be difficult or as a result of wear and tear in adverse conditions. The main constraint on the availability of wind power is the amount of wind. Even in the most favourable off-shore locations the average availability of wind generation in any large system is rarely more than 40% and it may be less than half that figure for onshore wind farms. Hence, the manager of a system with, say, 20 GW of nameplate wind capacity must assume that the maximum available capacity will rarely exceed 8 GW and may be much less. Most systems operate with a reserve margin of at least 15% at periods of peak demand – due to transmission constraints, breakdowns and other factors – so the practical contribution of 20 GW of nameplate wind capacity to system management is only 7 GW.

Capacity factor refers to the proportion of hours in a year that a plant is running, adjusted for any reduced capacity operations, whether or not the plant is dispatching electricity to the grid. The capacity factor matters for estimates of total fuel use and CO2 emissions.

In-feed factor refers to the actual amount (MWh) of electricity supplied by a plant to the grid during a year as a proportion of the maximum amount that it could notionally supply, i.e. rated capacity in MW x 8760 hours per year. The in-feed factor matters when considering the contribution that the plant or set of plants can make to meeting total demand for electricity.

The difference between the capacity factor and the in-feed factor arises from two sources:

- The nameplate capacity of a generating plant is invariably stated as a gross figure.[14] However, a portion of the gross production from any power plant is allocated to internal operating requirements, so that net output is less than gross output. Environmental controls such as precipitators and filters, scrubbers, catalytic converters, CCS units all consume electricity. The difference between gross and net output varies from 2-3% for a gas combined cycle plant to 15-18% for a coal plant with CCS.

· Periods when plants are operating as spinning reserve – i.e. with generators disconnected from the grid – are not included in the in-feed factor but they count as operating hours with respect to fuel and variable O&M costs. In some calculations, periods when plants are starting up or running down will also be included in the capacity factor, because fuel is used even if less than for full operation.

*Load facto*r is used sometimes to refer to the capacity factor of a plant and sometimes to its in-feed factor. At the system level, the usual convention is to calculate the load factor as the ratio of the GWh of electricity supplied in a year by a particular group of plants – e.g. all onshore wind farms – to the potential level of annual production at full rated capacity. This ratio is close or identical to the in-feed factor – depending upon how transmission losses and certain other items are treated. In this paper I have treated the load factor as the same as the in-feed factor, but that is not universal practice.

The confusion between the various ways of referring to plant availability and usage is unfortunate. It arises because the terms are used in different contexts and for different purposes. A single definition is not appropriate when considering the role of plants in meeting peak demand and total demand or for the purpose of calculating fuel use and emissions.

Thermal efficiency and heat rates. These parameters are used to specify the proportion of the heat content of a fossil or biomass fuel that is converted into useful electricity – as a percentage in the case of thermal efficiency or as xx GJ per kWh for heat rates. By convention, the efficiency of wind and hydro is cited as 100% because heat content of fuels is irrelevant in such cases. Similarly, the heat content of nuclear fuels is purely theoretical, so the usual procedure is to adopt an arbitrary value for the thermal efficiency of nuclear plants. In most cases the cited values for the thermal efficiency or heat rate of a fossil fuel plant refer to what can be achieved when the plant is operating stably under optimal conditions – for example, external temperatures can affect thermal efficiency. Such values will not be achieved during periods when the plant is starting up or running down. An open cycle gas turbine (OCGT) may be capable of operating at a thermal efficiency of 40%, but it will not come close to that efficiency on average if it is being run as a peaking unit to meet fluctuations in demand from one half-hour period to the next. The same is true for a combined cycle gas plant (CCGT) that may

14 The reported nameplate capacity of hydro plants is often overstated, as it may reflect a theoretical maximum level of generation that can only be achieved under very rare circumstances. This is one reason why systems which depend heavily on hydro power tend to operate with high reserve margins. On the other side, policy incentives, such as the Renewables Obligation, may prompt companies to down-rate the reported capacity of hydro plants where this would change eligibility for payments.

be capable of a thermal efficiency in the range 58-60% when run as a base load unit or 50-55% when run as a mid-merit unit.

There may be a trade-off between thermal efficiency and size, so that utilities and system operators have to balance investment in and use of large generating units that achieve higher thermal efficiency than smaller units but are less flexible in meeting fluctuations in demand. In contrast, wind turbines are small relative to the scale of the electricity system in any developed country (allowing for network connections). They are chosen to maximise reliability and the extent to which the wind resources at particular sites can be exploited.

These definitions may be used to consider three scenarios in which wind generation replaces gas generation at different points in the load curve.

A. **Base load generation**. Suppose that 10 GW of wind turbines substitute for 10 GW of gas combined cycle plant operating on base load. The average in-feed factor for new gas plants is about 92.6% (95% availability & 2.5% of gross output for internal consumption), so the net output from 10 GW of nameplate capacity would be about 81,100 GWh per year. The typical thermal efficiency for a modern CCGT is 59%, so total CO2 emissions would be 26.9 Mt of CO2 per year.

In recent years, the average in-feed factor for UK wind generation has been 27% which gives an average output of 23,650 GWh per year from 10 GW of nominal wind capacity. The remainder would have to be provided by gas OCGT plants operating on a stand-by basis. Under such a regime the thermal efficiency of the plants is unlikely to be higher than 35%, so total CO2 emissions would be 32.1 Mt of CO2 per year.

When wind generation displaces efficient base load plants it is correct to claim that more wind capacity leads to increased – not reduced – emissions of CO2. Indeed, the situation is much worse if wind generation displaces nuclear power with minimal CO2 emissions.

B. **Mid-merit generation**. Using the same capacity figures as in example A above, suppose that wind generation substitutes for mid-merit gas CCGT plants with an in-feed factor of 55% (typical for mid-merit plants). The thermal efficiency would be somewhat lower because of start-up and run-down periods plus periods as spinning reserve. It is reasonable to use a figure of 55% for thermal efficiency yielding total CO2 emissions of 16.0 Mt of CO2 per year.

The in-feed factor for wind generation in recent years reflects the fact that wind plants displace base load plants whenever they are available. The appropriate in-feed factor when they displace mid-merit generation will be much lower and will depend on the correlation between availability and demand. It is simplest to assume that in-feed ratio is 14.9%, i.e. 55% of the base load in-feed factor of 27%. Again, gas OCGT is used as backup. In this scenario total emissions with wind generation are 18.2 Mt of CO2 per year, still higher than with no wind generation.

C. **Peak load generation.** There is little to say when wind generation displaces peak load generation from gas OCGT used in the current system, since there is no difference between the efficiency and emissions for regular peak load plants and those used as backup for wind generation. Hence, there will be a reduction in CO2 emissions equal to the amount associated with the gas generation that is displaced.

These examples show it is perfectly reasonable to argue that adding wind generation to an electricity system may increase the level of CO2 emissions relative to its initial level. The worst outcome will arise if intermittent wind power displaces dispatchable base load generation with low or zero CO2 emissions – i.e. nuclear power or highly efficient gas plants. Claims that renewable energy schemes "save" X tons of CO2 typically rely upon a naïve calculation, assuming that 1 MWh of wind generation substitutes for 1 MWh of fossil fuel generation (1 for 1 substitution) with no adjustment for system-wide effects. While this may be good public relations, it is a very poor basis for making important policy decisions.

The analysis in this paper shows that any calculation of the change – up or down – in the level of CO2 emissions as a consequence of building more wind farms should be based upon very detailed modelling of how wind generation fits into the overall load curve at different times of year and with different assumptions about the composition of non-renewable sources of generation. However, it is possible to draw two fairly robust conclusions for the current situation.

- As explained earlier, the current incentives for renewable generation ensure that wind power displaces other sources of base-load generation when it is available. The technical characteristics of nuclear plants in the UK mean they are not suitable for load-following operation. Therefore, once the installed capacity of wind plants exceeds 15 GW – not later than 2015 according to DECC's projections - additions to wind generation will seriously affect the dispatch of nuclear power or coal with CCS for base load. Under those circumstances, the long run effect of wind generation will be to increase emissions of CO2 relative to a baseline with a lower level of installed wind capacity. This effect can only be avoided by shifting wind generation away from base load by changing the incentives for operating renewable sources of generation – and even that would be complicated.

- Any reduction in CO2 emissions associated with additional wind generation will be much lower than implied by the calculation assuming 1 for 1 substitution described at the beginning of this paper and in example C above. Estimates of the cost of reducing CO2 emissions by promoting renewable sources of generation that are based upon this approach (most of them) are simply wrong. The correct figures will be higher – often much higher – than those which are reported and used to justify current policies.

9. Alternative policies

The material presented in this paper has painted a dismal picture of the UK government's policies towards renewable energy and the reduction of CO2 emissions from the electricity sector. The response may be a variant of the "there is no alternative" argument, i.e. that other policy options will not ensure that the UK complies with its obligations to reduce CO2 emissions and stimulate renewable energy in accordance with national and EU targets. The logical answer to such arguments is that perhaps the targets ought to be reconsidered rather than pursuing expensive and ill-conceived policies. In the case of renewable energy this is almost certainly the correct response, since there is little or no benefit to be gained directly from reliance upon renewable energy. Its merits rest entirely upon the assumption that the use of renewable energy is a (relatively) inexpensive way of reducing CO2 emissions. If this is not correct, then it is perverse of the UK to shoot itself in the foot by promoting wind power and other sources of renewable power generation.

For the purpose of argument, let us take the UK's targets for reducing CO2 emissions as paramount and consider whether current policies offer a cost-effective way of meeting that target. One might hope not. I have referred to evidence from the US that the promotion of wind power involves an average cost of the order of $300 per ton of CO2 when assessed by looking at the operation of the electricity system as a whole. The figures for the UK are similar or higher. On reasonable assumptions, the costs of meeting the UK's targets for renewable power generation presented in this paper imply a marginal cost of the order of £270 per ton of CO2 when compared with the efficient outcome of investing in gas-fired generation – and even that estimate may be too low.

The EU's flagship scheme for reducing CO2 emissions from large sources, including the power sector is the Emissions Trading System (ETS). In practice, this has been a notable disappointment, partly because of the way in which it was implemented and partly because expectations for what the scheme could achieve were – and remain - unrealistic. Emissions trading arrangements are strongly promoted by some environmental economists, not only in the EU but also in the US and Australia. Unfortunately, many of the enthusiasts have little knowledge of how electricity systems work and rely heavily upon the experience of sulphur trading in the US, whose lessons are easily misunderstood.

There is no doubt that the US sulphur trading scheme has been a success, but it was a very special case. First, the scheme relies upon an elaborate infrastructure of data collection and regulation that had been developed over a period of 15-20 years prior to introduction of permit trading. Second, the allocation of permits was fixed for a much longer period than under the ETS and the scheme was expected to continue indefinitely. Third, and most important of all, the effective scope of the scheme is quite restricted and it has certainly not provided the basis for large investments in new generation technologies. The key point is that the sulphur trading scheme is primarily about reducing emissions of sulphur dioxide from large coal-fired power plants in the US Mid-West and Atlantic regions that existed in 1995. It has achieved this goal at a cost that was significantly lower than anticipated. But much of the increase in US electricity demand since 1995 has occurred in regions not covered by sulphur trading; even in the regions covered by the scheme, no coal-fired plants have been built since it was introduced. The industry has simply switched to gas-fired generation that is barely affected by sulphur trading.

The UK government has recognised that the ETS in its current incarnation is unlikely to provide the economic framework for future investment in reducing CO2 emissions. It has decided to adopt the idea, advocated by many economists, that a floor price for CO2 should be established with a commitment to increase it annually in real terms at least up until 2020. This is a significant step in the direction of relying upon a carbon tax rather than carbon trading as the economic instrument to reduce CO2 emissions. Unfortunately, the confused and inefficient jumble of levies, targets and other interventions designed to promote renewable energy and reduce CO2 emissions will remain.

There is little doubt that the most transparent and efficient way of reducing CO2 emissions over the next 20-40 years would be to set a carbon tax – or carbon floor price – that applies throughout the economy. No matter what its theoretical merits may be in restricted circumstances, no-one has ever demonstrated that carbon trading is either administratively feasible or efficient when applied on a universal basis. By relying upon a carbon tax, the whole nonsense of carbon budgets, etc, with overlapping and inefficient measures for each sector, could be swept away.

The standard objection to reliance upon carbon taxes is that they cannot guarantee that CO2 reduction targets will be met, whereas carbon trading arrangements can, at least in principle. The argument is disingenuous because it rests on the assumption that, collectively, the UK population would be willing to pay whatever it costs to meet CO2 targets, no matter how high the cost may be. If that assumption is not plausible, the question becomes: what is the maximum price per ton of CO2 we are willing to pay to reduce carbon emissions? That establishes a ceiling carbon price. If, as many believe, the ceiling carbon price is not high enough to meet the government's emission reduction targets, then it is the targets that will have to go and we finish up with a carbon tax based on the maximum cost that the public is willing to bear to reduce emissions.

The lack of transparency about the true costs of reducing CO_2 emissions implicit in current policies and targets may be a virtue for those convinced that reductions must be made but doubtful that the public would be willing to go along with the policy if they were aware of the costs involved. For anyone else, transparency about costs is a necessary condition for both efficiency in policy design and public acquiescence. It seems very unlikely that a marginal cost of £270 per ton of CO_2 is anywhere near the top of the ranking (from cheapest to most expensive) of policies intended to reduce carbon emissions or that this would be acceptable to the public. Hence, whether intended or not, the failure to assess and publicise the cost of alternative measures to reduce CO_2 emissions allows inefficient and costly policies to be pursued. A universal carbon tax would avoid this outcome and would provide a basis for ongoing debate about how much the UK is really willing to spend on reducing its carbon emissions in the context of what is happening in the rest of the world. Of course, since the future of global CO_2 emissions over the next 40 years will be driven primarily by what happens in China, this assessment might imply a rather broader strategy than one based on unrealistic targets for reducing the UK's emissions.

10. Final Thoughts

In a speech to a group of prominent business leaders the previous Secretary of State for Energy and Climate Change gave an extended soliloquy on his vision of greener growth for the UK – Huhne (2011). Nothing could better illustrate the gap between do-it-yourself economics and the realities highlighted by concrete economic analysis as presented in this paper. In Mr. Huhne's world all investment that comes under the category of greener growth is a good thing, irrespective of whether it generates adequate returns on capital that has to be diverted from other uses or whether it reduces emissions of CO_2 in practice.

The casual assumption that expenditures on green technology represent an efficient and economic use of scarce resources is little more than a convenient fairy tale for troubled times. Reality is rather different. Some green technologies will pay off – yielding satisfactory returns to both investors and users – but many will not. Ample experience tells us that any returns are likely to be smaller and take much longer to be earned than the enthusiastic projections produced by enthusiasts and lobbyists.

It is the – perhaps unfortunate - job of economists to be sceptical, subjecting such claims to detailed scrutiny. My goal in writing this paper was to examine investments in wind power in the UK from the perspective of the operation of the electricity system as a whole and in terms of the degree to which they would contribute to meeting the UK's targets for reducing CO_2 emissions. Apropos Mr Huhne's vision, the returns on investment are low whereas the cost per ton of CO_2 saved is very high. Clearly, this is one green technology that will not contribute much to any variant of green growth for the UK.

In recent months DECC has begun, albeit reluctantly, to acknowledge that large investments in renewable energy will push up electricity prices. The counter-argument is that the Green Deal will mean that household energy bills may fall or, at least, not increase substantially relative to the Government's projections of "business as usual". This argument is unsound at best for several reasons.

A. The key element which will hold down energy costs in this vision of the future is the savings made possible by implementing energy efficiency measures. Energy saving has been the elusive solution to uncomfortable energy choices for at least 30 years. Up to now the results have been disappointing. Perhaps, the outcome will be different this time around, but mostly the proposals seem to involve bribing people with their own money to make significant investments with quite uncertain returns.[15] In any case, the merits of energy efficiency policies are quite independent of any commitment to renewable energy. If such policies are really justified, then they can and should be implemented on their own. Combining unrelated policies into a single package gives the impression of clutching at straws and may well undermine the effective pursuit of less ambitious but more achievable goals.

B. The claim that energy costs will rise rapidly over the next 20-30 years rests on a critical assumption about future gas prices. When this is challenged, especially with respect to the potential impact of the development of reserves of shale gas, the usual response is that the UK (or Europe) is not like the US and the impact of shale gas will be small at best. This encapsulates a fundamental misunderstanding of the gas market. Shale gas production in the UK may or may not be a huge windfall, but it is almost irrelevant to future energy costs. Without going into too much detail there are three things that we should have learned over the last 30 years: (i) natural gas is an extremely abundant resource; (ii) in the long run gas prices are determined by the cost of investing in production and infrastructure; and (iii) large investments in LNG capacity mean that previously separate markets are more integrated today and will be even more so in future. The gas market is prone to cyclical fluctuations due to changes in the balance between supply and demand, but there is a strong tendency for prices to revert to a band around $8 per million Btu (MMBtu) in real terms. Prices less than $6 per MMBtu are too low to sustain investment in production, even in the US, while prices much above $10 per MMBtu will induce large invest-

15 A personal example illustrates the point. The Energy Saving Trust offers a grant of £400 to anyone replacing a domestic heating boiler with a thermal efficiency of 70% or less. I investigated whether it would be economic to replace a relatively old (24 years) oil-fired boiler with a new one, with or without the grant. This is likely to be the best possible case for a boiler replacement because of the high price of heating oil. After carrying out a careful investment appraisal my conclusion was that even with the grant the expected rate of return on the investment was likely to be less than 8% with a fairly high probability that it would be less than 4%. The reason was illuminating: the introduction (and uncertainty about the application) of other building regulations pushed up the initial investment to about 3 times the total cost of a new boiler alone. This is a classic example of the lock-in effect caused by poorly designed regulation which has often been noted by environmental economists.

ment in the infrastructure required to develop and transport large reserves of gas around the world. As a consequence, DECC's policies involve a huge fixed investment for a future that is both unlikely and highly uncertain. The history of energy policies around the world is replete with examples of similar interventions that have proved to be misjudged. Again, this time may be different but the track record cannot give much confidence that it will be.

C. The final element of the DECC view of the world is energy security and independence. This is a concept that is repeatedly abused as a justification for uneconomic policies and projects. The best guarantee of energy security is the combination of a vibrant economy and a commitment to a market regime of prices, taxation and regulation that provides an expected return on investment that is commensurate with the risks involved linked to prices that customers are willing and able to pay. The UK's record of intermittent – and sometimes highly disadvantageous – interventions in energy markets and adjustments to the tax regime is unlikely to give investors the confidence to make the type of large and inflexible investments that are required to provide this kind of energy security. It is an old aphorism to observe that something which cannot be sustained will not be sustained. This is the case for current incentives for wind generation. They are unconscionable in the long run, so the question that must be addressed by any rational investor – under both the ROC regime and the new EMR proposals - is whether it is possible to recover one's investment in the (uncertain) period before they are changed yet again. It was recognised long ago that a regime relying upon large subsidies to farmers could not provide long term food security. That lesson is no less valid when applied to wind farms and energy security.

There is nothing inherently good or bad about investing in renewable energy and green technology. In other industries, the returns on innovation are eroded by competition which transfers the benefits of technical advances from producers to consumers. This is what has happened in power generation as the improvements in efficiency offered by gas combined cycle plants have been passed through as lower real prices for electricity. Unfortunately for current policies, this market dynamic undermines the case for investing in technologies that are capital intensive and require a long period of operation to earn an adequate return. The response has been to rig the market to (in effect) guarantee the return on investment in immature technologies which are not economic at any reasonable price on CO_2 emissions or if their impact on landscapes and the environment was properly internalised.

If there were strong evidence that the investment costs of wind power will fall rapidly, then a case could made that the UK should promote wind power on a small scale in order to gain the benefits of learning by doing. The facts do not support such a case: despite large investments around the world the real costs of onshore wind installations appear to have stabilised. Without some fundamental technical change, onshore wind power is going to remain uneconomic, especially if external costs are taken into account. The opportunities for reducing the costs of offshore wind power are greater but it has much further to go.

The key problems with current policies for wind power are simple. They require a huge commitment of investment resources to a technology that is not very green, in the sense of saving a lot of CO2, but which is certainly very expensive and inflexible. Markets have to be rigged in order to persuade investors to fund the investment that is required. The economic cost of fixing markets in this way, especially if there is a possibility of making mistakes, is very high. Before proceeding along this path, any Government ought to be very sure that (a) the economic and environmental benefits outweigh the substantial costs incurred, and (b) the risks of pre-empting better options that may emerge in future have been minimised.

In reality, neither of these conditions is close to being satisfied. To misquote another aphorism, unless the current Government scales back its commitment to wind power very substantially, its policy will be worse than a mistake, it will be a blunder.

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