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Total cost estimates for large-scale wind scenarios in UK

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Abstract

The recent UK Energy White Paper suggested that the Government should aim to secure 20% of electricity from renewable sources by 2020. A number of estimates of the extra cost of such a commitment have been made, but these have not necessarily included all the relevant cost components. This analysis sets out to identify these and to calculate the extra cost to the electricity consumer, assuming all the renewable electricity is sourced from wind energy. This enables one of the more controversial issues—the implications of wind intermittency—to be addressed. The basis of the assumptions associated with generating costs, extra balancing costs and distribution and transmission system reinforcement costs are all clearly identified and the total costs of a "20% wind" scenario are compared with a scenario where a similar amount of energy is generated by gas-fired plant. This enables the extra costs of the renewables scenario to be determined.

The central estimate of the extra costs to electricity consumers is just over 0.3 p/kW h in current prices (around 5% extra on average domestic unit prices). Sensitivity analyses examine the implications of differing assumptions. The extra cost would rise if the capital costs of wind generation fall slower than anticipated, but would fall if gas prices rise more rapidly than has been assumed, or if wind plant are more productive. Even if it is assumed that wind has no capacity displacement value, the added cost to the electricity consumer rises by less than 0.1 p/kW h. It is concluded that there does not appear to be any technical reason why a substantial proportion of the country's electricity requirements could not be delivered by wind.

Keywords: Wind energy costs; Renewable electricity generation; Integration of wind energy

1. Introduction

The recent UK Energy White Paper states the Government's goal of sourcing 20% of energy from renewables by 2020. Although this has been welcomed in many quarters, others have criticised the likely extra cost to the electricity consumer. Buried within the supporting documentation to the White Paper are a range of cost estimates for renewable generation sources in the future, but the only estimates of extra electricity costs within the White Paper do not make the exact basis clear.

There are three principal components of extra costs: the generation costs, costs of distribution and transmission system reinforcements and, in the case of the intermittent renewables, extra balancing costs. The White Paper notes that, given the extensive wind resources available in the UK and the on-going progress in developing onshore and offshore wind generation technology, that wind could be the predominant renewable technology. However, wind is an intermittent source of power and some of the best locations for turbines are remote from the main load centres in Great Britain. This gives rise to costs in all three of the categories identified above. As wind energy is now well established, its costs and performance can be characterised reasonably well, and this analysis focuses solely on this technology.

A number of recent studies have sought to quantify the costs associated with large-scale renewable generation. In particular, a recent study by ILEX and UMIST (Ilex and Strbac, 2002) for the DTI examined in some detail the system and network costs arising from a range of renewable scenarios (referred to as the SCAR study in this paper). This paper draws extensively from the ILEX/UMIST work but concentrates on the overall cost implications of a large-scale adoption of wind power in Great Britain. It seeks to provide conservative estimates

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of both the costs and benefits of large-scale development of wind power compared to using fossil fuels. By illustrating the interactions between generation, network and system operation related costs, it aims to identify the various cost areas and the relative importance of the various uncertainties that exist.

2. Methodology

This paper estimates the costs that underlie the price of electricity paid by the generality of end customers. Such costs comprise:

(i) Generation investment costs (including the impact of wind on the need to establish and maintain other generation capacity).
(ii) Short-run marginal energy production costs (fuel) including that required to meet network losses and undertake system balancing due to variations in demand, generation availability and wind production.
(iii) Network costs—both connection and infrastructure—reflecting the need for new assets and the maintenance and replacement of existing assets as patterns of production and consumption of electricity change.

As these costs include the capital cost of plant that is expected to last many years as well as costs that vary according to the amount of electricity produced and transmitted, it is necessary to combine these costs in order to compare scenarios. In this paper, capital costs are expressed as annuities assuming typical plant lifetimes and industry costs of capital and then allocated pro-rata to all kW h s produced in the target year (i.e. 2020). This approach allows a simple comparison of scenarios by assuming the same static system requirements are satisfied in each case.

As far as possible, cost assumptions are presented in a form that can be compared with prices observable today. However, the reader will need to take care in comparing costs in this paper with observed wholesale and retail market prices because such prices will depend on the allocation of network charges to the various market participants. A 2003 price base is used throughout this paper.

3. Scenarios

For simplicity, this paper compares just two main scenarios:

(A) *A "conventional" scenario representing the year 2020 in which electricity is predominantly produced by thermal generation (coal and gas)*

Demand levels and energy requirements are assumed to have increased by around 17% from those existing today as a result of modest load growth. (For example, the result of moderate economic growth and progressive improvement of energy efficiency measures including CHP.) GB electricity sales in 2020 are taken to be around 400 TW h and the GB peak demand around 70 GW. (Given that all costs will be expressed per kW h of energy produced, the results in this paper are not particularly sensitive to these background assumptions.)

Sufficient conventional generation capacity is assumed to be established such that, in the absence of market price response, demand would need to be disconnected not more than one winter in ten. This statistical approach to determining the required generation capacity is likely to differ from that which might be delivered by the current electricity market but permits computation and comparison.

(B) *A "wind" scenario with identical electricity consumption to that assumed in Scenario A, but with almost 20% of electricity produced by wind turbines*

In this scenario around 26 GW of wind capacity is established, which at an average 35% load factor produces 20% of electricity sales. As an initial weighting of the various costs identified in this paper, it is further assumed that approximately 60% of wind capacity will be located offshore and the majority of this will be directly connected to the transmission system. Most onshore wind is connected to distribution networks at 132 kV or lower.

The introduction of wind capacity in Scenario B not only reduces the fossil fuel burn compared to Scenario A but also permits the amount of conventional generation capacity to be reduced while still achieving the same load security, in terms of the probability of lost load. Given the intermittent nature of wind, however, the reduction in conventional generation capacity is not a simple one-for-one relationship but must be reflected in an appropriate capacity credit that reduces as the installed wind capacity increases.

4. Capacity credit of wind

The total capacity of installed generation must be larger than the system maximum demand to ensure the security of supply in the face of variations in demand due to adverse weather, demand forecast errors during the lead-time for constructing new capacity, generation breakdowns and interruptions to primary fuel sources. The current electricity market does not contain a statutory or formal generation security standard that would define the required capacity margin for a particular mix of generation types. To make an explicit calculation, however, we have taken the last security standard employed in the UK as indicative of the security of supply that would be acceptable (Electricity Council, 1985). The security standard was defined in terms of the statistical probability that consumers of electricity may be faced with the loss of their supplies due to insufficient generation. This risk was expressed in terms of the chance of needing to interrupt supplies not being more that nine winters in one hundred (i.e. a 9% risk). Assuming no increase in this loss of supply risk, we have evaluated the amount of conventional generation that can be displaced by wind generation (using the annual half-hourly profiles of wind outputs, developed from historic wind generation data).

The contribution of wind generation to capacity depends on the correlation of wind output with demand and varies with the proportion of capacity provided by wind. Anti-correlation is often intuitively expected after considering the apocryphal scenario in which an anticyclone "cold snap" gives high demand but little wind anywhere in the country. On the other hand, short-term electricity forecasters are aware of the strong positive correlation between demand and "wind chill".

In terms of quantitative analysis, the SCAR study used a 1-year time series of actual wind generation data. While this dataset provided statistically significant observations of the general variability of wind and correlation with demand, it is too short to permit wind variations during high demand conditions to be extensively sampled. However, analysis of a 5-year time series of wind speeds used by National Grid in an assessment of balancing requirements, and an earlier study by the CEGB, do not provide any statistical evidence for wind variations at peak being substantially different to those at other demand levels for similar times of the year. A more detailed analysis of the issues, with results from various British and overseas studies, came to a similar conclusion (Milborrow, 1996). On this basis, we have assumed in this paper, for the purposes of assessing capacity credit, that the typical distribution of wind output seen in the various time series available to us will also occur during high demand conditions. However, recognising that some uncertainty remains in this area, our analysis permits the effect of more pessimistic assumptions to be assessed.

The variation of the capacity credit for wind with the relative proportion of wind in the plant mix derives from the different statistical distributions of wind and conventional plant variations. With low penetrations of wind, the skewed nature of the distribution of wind output has very little impact on the need for a plant margin. However, as wind capacity becomes a larger proportion of the plant mix, the distribution of wind output becomes increasingly important and reduces the capacity credit that can be given to wind.

On the basis of our analysis we find that for a small level of wind penetration the capacity value of wind is roughly equal to its load factor, approximately 35%. But as the capacity of wind generation increases, the marginal contribution declines. For the level of wind penetration of 26 GW, about 5 GW of conventional capacity could be displaced, giving a capacity credit of about 20%.

5. Cost assumptions

For almost all the cost areas estimated in this paper the actual future costs are subject to considerable uncertainty. The results presented in this paper represent the authors' views on these ranges and on a suitable choice of a 'representative' value for the purposes of producing an estimate of the overall cost. We seek to use our representative value to give a cautious overall cost comparison between our scenarios and the range of uncertainty to illustrate the sensitivity of total costs to these assumptions. Turning to each cost area in turn.

5.1. Generation plant costs—gas

Gas-fired generation has been the predominant source of new generation since 1990, and so we assume renewables are likely to defer the construction of new gas-fired plant. For the purpose of cost comparison, attention must therefore be focused on the likely price movements in this technology.

Installed costs for new CCGT in the UK in recent months are reflecting higher insurance and staff costs, and the need to make provision for higher commissioning costs under the New Electricity Trading Arrangements. The two most recent complete contracts come out at £450/kW (Power UK, 2003). An earlier analysis suggested an average installed cost of £500/kW. The lower figure has been used, and it is assumed that this includes interest during construction.

Gas turbine technology is still developing and the US Department of Energy anticipates a modest fall of 7% in capital cost by 2020. This corresponds to £420/kW, but the slightly lower—and therefore more conservative—price of £400/kW has been used for this analysis. The US DoE does not anticipate any change in operation and maintenance costs and so the current figure of £20/kW/yr has been used, which excludes annual network costs. Availability has been taken as 85% in each case.

The average price for gas paid by the electricity generators in 2001 was 22.5 p/therm, which translates to a fuel cost (assuming 50% thermal efficiency) of 1.32p/kW h. Although the average for 2002 may be slightly lower, a figure of 1.3 p/kW h for 2020 has been taken as a representative estimate. As there are expectations that gas prices will rise, an alternative figure of 27 p/therm for 2020 has been used, in line with a recent DTI paper (DTI, 2001). The corresponding fuel price is 1.6 p/kW h. These fuel prices include the gas transportation costs for delivery to the power stations.

5.2. Generation plant costs—wind

The price of wind energy is falling rapidly. It is important to compare "like with like", and so prices bid into the Non-Fossil Fuel Obligation—which offered 15-year contracts—are a good guide. Taking the minimum bids, prices (1998 levels) fell from 4.56 p/kW h in 1994–2.43 p/kW h in 1998. The introduction of the Renewables Obligation in the UK has masked the underlying trends, as a shortage of all renewables, plus future renewable obligation uncertainties, has driven up prices. Nevertheless, contract prices in the United States reflect a continuing downward trend.

The present-day installed cost for onshore wind in the UK is about £650/kW, and for offshore around £1000/kW (DTI, 2002). For offshore wind this includes around £100/kW for the farm to shore connection and £150/kW for inter-turbine cabling. A number of recent studies have suggested that the corresponding price in 2020, onshore, will lie between 55% and 70% of the present level (Milborrow, 2002). Offshore prices may show a bigger drop, partly due to maturation of the industry and partly due to the moves towards much bigger wind farms. There are fewer estimates for offshore prices in 2020, but the range is between 40% and 70% of present costs. The representative estimates selected for this analysis are £455/kW for onshore and £600/kW for offshore.

These values are believed to be conservative. The compound growth rate from 1990 to 2002 was 27.7% and the "learning curve ratio", i.e. the price reduction per doubling of capacity, was about 15% (Milborrow, 2002). If these trends continue, the 2020 costs would be expected to be 40% of 2002 values.

Operation and maintenance costs for wind plant vary. Onshore values lie in a range between 10 and £20/kW/yr, so a "central" value of £15/kW/yr is used, declining by just under 2% p.a., to reach £11/kW/yr by 2020. Offshore, fewer data are available. The DTI suggest £36/kW/yr may be appropriate for early installations, while actual costs at Middelgrunden (off Copenhagen) are reported to be around £12/kW/yr. As the trend towards large wind farms offshore is likely to result in significant cost reductions, £24/kW/yr may be taken as a "typical" value at present, falling to £20/kW/yr by 2020

As UK wind speeds are similar, offshore and onshore, a common value of 35% is used for the load factor, based on typical wind speeds around 8.3 m/s, and allowances for availability, array and electrical losses.

5.2.1. Extra balancing costs

As the amount of wind generation on an electricity network increases, and the uncertainties in wind output start to become evident above the normal level of uncertainty in balancing supply and demand, some extra balancing costs will be incurred. This will require extra reserve and frequency response to be scheduled and utilised. Estimates were made for the PIU study, which separated the "technical" costs from the extra plant needs (Milborrow, 2001). The technical costs arise as reserve plant is part-loaded and, in consequence, operates at lower efficiency; extra plant may be needed if the existing capacity is insufficient, but the amounts involved are very modest—around 5% of the wind plant capacity, at the 20% penetration level. Estimates of extra reserve costs from the National Grid Company (Dale, 2002), used market costs, which may be expected implicitly to include a capital recovery element. Estimates in the SCAR report tie in with both of these (with a spread of $\pm 10\%$). A value of £2.38/MW h of wind produced for 10% wind is used, rising to £2.65/MW h at 15% and £2.85/MW h at 20%.

The cost of balancing other demand and generation variations (as used in the *conventional* scenario) is assumed to be £345 m per annum, corresponding to the latest target for the System Operator balancing incentive scheme, after removing the transmission loss target allowance.

5.2.2. Extra emissions

The additional part-loaded plant required for balancing leads to a small increase in emissions. With 20% wind energy, however, the extra capacity of the reserve is about 5% of the rated capacity of the wind plant. The reserve still contributes useful energy to the system, so the extra emissions are those associated with the reduced efficiency of part-loaded plant. Taking a conservative estimate of 10% for the reduced efficiency, and taking into account the fact that the load factor of wind plant is just under half that of thermal plant, this suggests that the emission savings from the wind will be reduced by a little over 1%. This can be compared with the 20% of fossil fuel avoided by using wind generation.

6. Transmission network costs

The location of wind generation, like conventional generation, can have a significant effect on transmission. Historically, transmission costs have been driven by a north–south flow from thermal generators located predominantly in the north, to demand in the south. With significant wind resources in Scotland and off the North West and North East of England and North Wales coasts, it is possible to envisage scenarios where this pattern of flows endures, despite the retirement of many of the existing conventional stations, thereby increasing the requirement for transmission reinforcement and the level of transmission losses.

Alternatively, if onshore wind generation were developed across Great Britain and included the offshore wind resources around the England and Wales coast, then transmission reinforcement costs could be significantly smaller. Furthermore, the location of new conventional generation and of decommissioned plant will also have a considerable impact on the future needs for transmission capacity.

The NGC studies reported in the DTI's Future Offshore consultation document show costs of between £275m and £615m to accommodate 8 GW of wind, i.e. between £35/kW and £77/kW.

In the SCAR study the effects of connecting wind farms at various location across the country on the transmission reinforcement cost was considered. This included the impact of the locations of new conventional plant and decommissioning of existing generation. The range of cost was found to be between £65/kW and £125/kW of wind generation capacity. Lower values correspond to scenarios with dispersed wind generation connections, with significant proportions of offshore wind around the England and Wales coast, while the higher values correspond to the scenarios with considerable amount of wind being installed in Scotland and North of England. Still higher costs could be obtained if all existing conventional generation is assumed to remain in service in Scotland and northern areas. The effect of these wider ranges is illustrated in the sensitivities shown below.

In this paper £100/kW is used as a representative value for transmission infrastructure costs. For 26 GW of wind, this implies capital investment requirements of £2.6b, but given the range of costs in the SCAR study, the investment, depending on its location, will be between £1.7b and £3.3b.

The cost of connecting dispersed wind generators in remote areas to the main transmission network may be significant. For example, the cost of connecting renewable resource from the Western Isles in Scotland (PB Power, 1999) or connecting offshore wind farms to the transmission system may be considerable. Average wind connection costs are assumed to be in the range of £40–£70/kW reflecting a combination variety of siting and different scope for economies of scale. £50/kW is used as a representative value. Assuming 60% of wind is directly connected to the transmission system gives a connection capital investment requirement between £0.6b and £1b.

As discussed earlier, wind generation may contribute to reducing the demand for conventional generation capacity. This would avoid transmission connection costs in the order of £60 for each kW of conventional generation displaced (assuming an average connection cost of £30/kW and a similar amount for avoided infrastructure reinforcement). For 20% of wind generation penetration, the overall value of transmission savings will range from zero, if no capacity credit is given, up to about £300 m if 5 GW of conventional plant can be displaced.

7. Distribution network costs

It is anticipated that a substantial proportion of the required new renewable capacity will be connected to the distribution network. There are likely to be significant costs involved in connecting, and operating substantial volumes of renewable generation at the distribution level. The range of costs presented in this section is drawn from analysis undertaken for the *SCAR* report. The distribution costs cover the reinforcement costs required to the distribution network to accommodate new generation, but exclude the costs of physically connecting individual wind turbines as these are included in the generation capital costs given above. The costs presented in this paper differ from those in the SCAR report, in that this paper covers the period to 2020 and all distributed generation, whereas SCAR related to the costs of an additional 10% or 20% renewables beyond 2010.

Connecting new generation to the distribution system is likely to trigger reinforcement costs if that new generation affects voltage management, equipment thermal ratings or system fault levels. Costs will be incurred from the replacement of switchgear to accommodate increased system fault levels, or the reinforcement of circuits and building of new substations, to manage network voltage and thermal ratings. The total amount of new capacity, the size of individual projects, the voltage level at which they are connected and their location will all affect the magnitude of costs.

Renewables are not the only form of distributed generation and over the period to 2020 it is anticipated that there will also be significant growth in non-renewable distributed generation, such as combined heat and power (CHP) projects. There is a Government target for 10 GW of CHP plant by 2010 and there is growing interest in the use of domestic CHP plant to replace household central heating boilers over the period to 2020. These non-renewable projects, expected in both the *conventional* and *wind* scenarios, will impose new costs on the distribution system which may amount to approximately £400m over the period to 2020, equivalent to an average cost of £36/kW. The effects of these costs are included in Table 1, and the SCAR report, but as they are common to both scenarios, are not included in the total cost comparison.

The additional costs to the distribution system under the *wind* scenario, where 20% of energy requirements are met from wind generation, are expected to be in the range of £34/kW–£41/kW, resulting in total distribution costs to accommodate both CHP and renewables between £700m to £1bn. The lower end of this range is more likely to be realised if a substantial proportion of the renewable capacity comes from large (100 MW and above) offshore wind projects, that would be likely to connect at transmission voltage, thereby avoiding distribution costs. Alternatively, the application of active management to distribution systems, despite its upfront costs, might also result in costs towards the lower end of the range. The higher end of the cost range would be more likely if wind developments comprise a more equal mix of onshore distribution connected generation (of varying sizes) and offshore transmission connected schemes. Costs might also be expected near the higher end of the range if distributed generation is clustered around a few connection points rather than spread over the rural network. The table presents the total distribution costs derived from various scenarios examined in the SCAR study.

In determining a representative value for distribution costs under the *wind* scenario, we have taken a view on the most likely scenario for the development of wind generation, based on current experience. Whilst we are confident that offshore wind can play an important role in meeting the UK's renewable targets, it is likely that a large number of onshore wind projects, of varying sizes and connected at different distribution voltages will also

Table 1
Distribution costs related to connection of distributed generation to 2020

SCAR scenario	Distributed capacity (GW)	Base cases		Active management		Clustered	
		Total cost (£m)	Average cost (£/kw)	Total cost (£m)	Average cost (£/kw)	Total cost (£m)	Average cost (£/kw)
No renewables	11	380	36				
North wind	25	990	40	880	36	1020	41
Wind & Biomass	21	730	35	720	35	750	36
Diverse	26	970	37	880	34	1030	39

Table 2
Cost comparison of scenarios

Coat area	Cost	(a) Conventional scenario			(b) Wind scenario		
		Capital (£m)	Annual (£m/yr)	Unit costs (p/kW h)	Capital (£m)	Annual (£m/yr)	Unit costs (p/kW h)
1. *Generation costs*							
Conventional capacity (CCGT)	400 £/kW	33,600	3947	0.99	31600	3712	0.93
Annual operating cost	20 £/kW/yr		1680	0.42		1580	0.40
		84 GW installed capacity			79 GW installed capacity		
Offshore wind turbines	600 £/kW				9360	1099	0.27
Annual operating cost	24 £/kW/yr					374.4	0.09
					15.6 GW installed capacity		
Onshore wind turbines	455 £/kW				4732	556	0.14
Annual operating cost	15 £/kW/yr					156	0.04
					10.6 GW installed capacity		
Total generation costs			5627	1.41		7477	1.87
2. *Variable costs*		400 TW h sales + 8% losses			As Scenario A + 80 TW h wind		
Fuel	13 £/MW h		5616	1.40		4576	1.14
Balancing costs (excluding losses)			345	0.09		573	0.14
Total variable costs			5961	1.49		5149	1.29
3. *Network costs*							
Conventional tx connection (shallow)	30 £/kW	2520	173	0.04	2370	163	0.04
Conventional infrastructure (deep)	30 £/kW	2520	173	0.04	2370	163	0.04
Offshore wind tx connection (shallow)	50 £/kW				780	53	0.01
Onshore wind distribution costs	40 £/kW				416	29	0.01
Transmission infrastructure (deep)	100 £/kW				2600	178	0.04
Total network costs			346	0.09		585	0.15
Total scenario costs			11,933	2.98		13,212	3.30

be developed. This would suggest average distribution costs of £40/kW to accommodate the distributed generation in the *wind* scenario, including 10 GW of wind at a capital cost of around £420m.

8. Total cost comparison

Using the various cost assumptions described above, Table 1 compares the costs of our conventional plant and wind scenarios. For the purpose of making these comparisons, capital costs are expressed as annuities so that they can be allocated to each unit of electricity sold. To represent the different costs of capital arising in the generation and network sectors, annuity factors for generation costs are calculated using a 10% discount rate for an assumed 20-year plant life whereas the network annuity factor uses a 6.25% discount rate assumes a 40-year plant life.

These cost summations exclude the wider transmission and distribution network costs that are assumed to remain constant between the two scenarios (e.g. the infrastructure and operational costs associated with connecting and ensuring the quality and security of supply to demand customers). (Table 2).

Using these representative but cautious assumptions, the additional cost of 20% wind is just over 0.3 p/kW h sold (or around 1.6 p/kW h of wind produced). This corresponds to a little under 5% of the average domestic unit price. The effect of the various uncertainty ranges identified in this paper on this cost difference is shown in Fig. 1.

This illustrates how the capital cost of wind turbines is the most important uncertainty in terms of the difference in costs between the conventional and wind. If wind capital costs do not fall from present values in real terms then the additional costs of the wind scenario would increase to 0.5 p/kW h of sales (2.5 p/kW h of wind). However, if wind capital costs continue to fall as historically observed, then the resulting reduction in overall costs would be larger than the costs required if, as a very worst case, no capacity credit is attributed to wind. The analysis also shows that fossil fuel prices, achieved load factor and the proportion of the more expensive offshore technology and the cost of capital for generation projects are more important uncertainties than those associated with network costs.

9. Conclusions

This paper has estimated the additional costs that would arise if 20% of electricity requirements were produced from wind power. Using conservative assumptions, the total additional cost is estimated to be around 0.3 p/kW h consumed (1.5 p/kW h of wind produced)—just

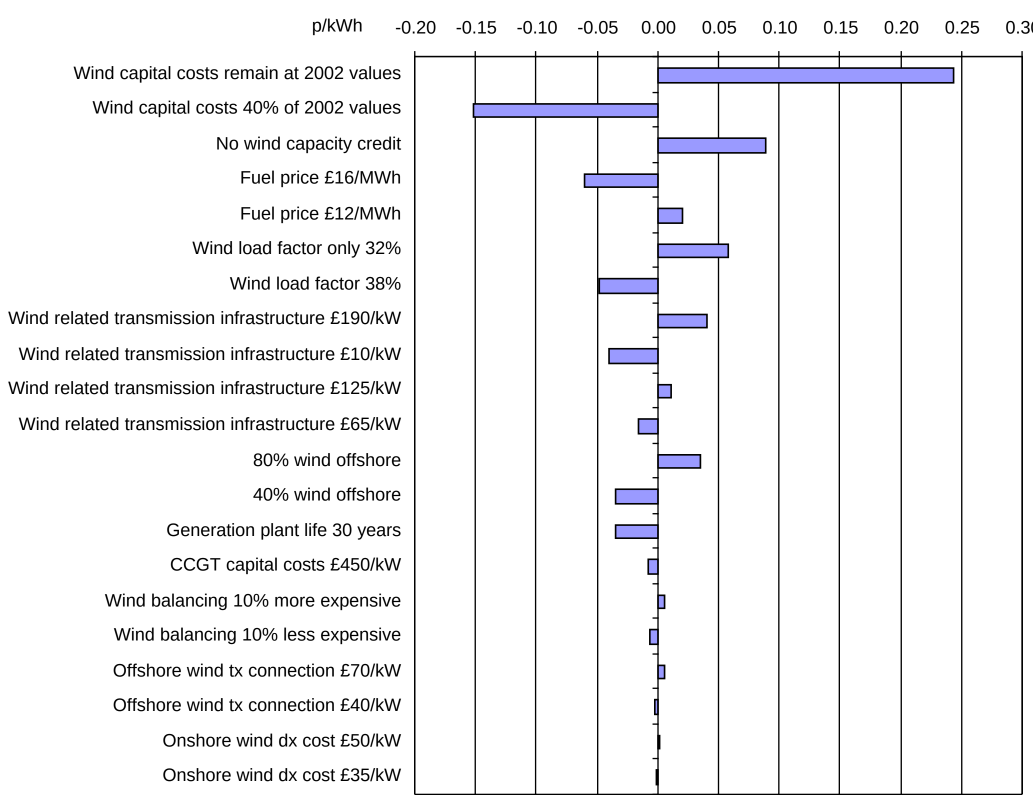

Fig. 1. Effect of uncertainties on additional costs from wind.

under 5% of the average domestic unit price. The methodology used seeks to compare like for like, in particular by representing generation capacity, system operational costs and network reinforcements that may be needed to maintain the reliability and quality of supplies as currently experienced. It illustrates how wind would reduce the need for fossil fuels and also reduce, albeit to a lesser extent, the need for conventional generation capacity that would otherwise be required.

On the basis of the analysis underlying this paper, the details of which are published elsewhere, there does not appear to be any technical reason why a substantial proportion of the country's electricity requirements could not be delivered by wind. While the investment needed in generation and networks is substantial, they are not significantly beyond precedent. For example, the need for some 26 GW of wind generation across Great Britain by 2020 may be compared with the development of around 24 GW of CCGT power stations in England and Wales since 1990. Similarly, the need for £2.5 bn to £4 bn of transmission investment to accommodate wind can be compared to the £3.5 bn of invested by the National Grid Company in its network since 1990.

The actual costs associated with developing 20% wind are subject to a number of uncertainties which this paper has sought to illustrate and rank. The most important factor is the extent that wind turbine capital costs will fall as a result of "learning by doing". The load factor and capacity credit actually achieved are also key values.

Of the network costs, transmission infrastructure and balancing costs are the most significant. The infrastructure cost depends strongly on the location of wind developments as well as the extent to which network capacity continues to be used by conventional plant in the north of the country. Balancing costs depend on many issues including the extent of geographical diversity, the accuracy of wind prediction techniques, and the development of the balancing services market with potentially larger contributions from the demand side and interconnectors.

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