WIND ENERGY: THE WAY FORWARD FOR IRELAND

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SUMMARY

With world energy prices in turmoil, the security and future price of natural gas — the likely staple fuel for Ireland's electricity supply industry in the future – are uncertain. Ireland has, however, some of the highest wind speeds in Europe and its wind energy generation costs are not much higher those of gas-fired plant. The cost of wind energy has fallen steadily in recent years and continues to fall, and with rising gas prices it is only a matter of time before electricity generated from wind in Ireland will cost less than that from thermal plant.

Wind generation is considered a mainstream generation option in a significant and increasing number of countries, including the United States. Measures must now be taken to make it mainstream in Ireland. There are no insurmountable technical issues restricting its development: the costs of the extra reserve needed to deal with the additional uncertainty due to wind are modest and the need to constrain wind plant down or off is unlikely to become a significant issue until it supplies about 20% of electricity demand. Furthermore, the connection of wind farms to the national grid can be achieved on a significant scale and on a commercially viable basis in a wide range of locations.

This paper examines the likely costs payable by Irish electricity consumers under a range of scenarios with wind contributing up to 23% to electricity supply by 2010 and 41% by 2020. It is anticipated, on the basis of realistic assumptions about gas prices and wind plant costs, that while a modest extra cost will be attributable to wind-generated power up to 2010, it will become cheaper than power from thermal plants from then onwards. The analysis uses data from reputable sources and takes into account all costs associated with the variability of wind, including extra balancing and the fact that progressively less thermal plant is saved as the amount of wind energy increases.

While the estimates for later years with high wind contributions are naturally less certain, worldwide advances which will ease the assimilation of increasing amounts of wind are well underway and are likely to provide solutions that reduce the cost impacts. Current research covers wind forecasting, more sophisticated demand-side management techniques and improved control systems for wind turbines. Interconnection with Wales will also assist significantly in this regard.

1. INTRODUCTION

Ireland has the potential to generate the cheapest wind energy in the whole of Europe. It has the best wind resource, as it is the first landmass for several thousand miles to intercept the prevailing westerly winds. Apart from a small area in the South of France, only Ireland, Denmark and Scotland have substantial areas of land where the wind speeds at 50 metres above ground level, on open plains, are above 7.5 metres per second[1]. However, Denmark is relatively flat, and so derives minimal benefits from the enhanced wind speeds on hilltop sites. Wind farm capacity factors in the range 30-36%, or above, may be expected in Ireland, and this is confirmed by the limited amounts of data that are available.

Unlike western Denmark, where wind energy contributes around 20% of the electricity supply, Ireland does not presently have robust electrical connections with its neighbours. (Although it does have access, indirectly, to the link from Northern Ireland to Scotland). However, numerous utilities have examined the implications of operating with increasing amounts of wind energy and all have concluded that modest amounts (up to around 20%) can be accommodated with modest changes to operating procedures and at modest cost. As the build up of wind energy would be gradual, there will be time to make adaptations, whilst construction of an additional link from Ireland to Wales would bring considerable benefits to the electricity system as a whole, apart from facilitating the further growth of wind energy.

At a time when concerns are being expressed, worldwide, about excessive reliance on gas, and when future oil and gas prices are very uncertain, the availability of good wind resources is important. Concerns about the availability and price of gas are unlikely to abate, as there has been a significant shift away from oil and towards natural gas for electricity generation during the last 30 years. Gas accounted for 21% of primary energy and 18% of electricity generation, worldwide, in 2001[2], whilst world primary energy demand almost doubled between 1971 and 2001 and is expected to increase by another 40% by 2020. Recent data on gas price futures suggests next autumn's prices (3Q05) are about 50% higher than they were in January 2003.

In Ireland, wind is an inherently secure source of energy as its resource availability is not determined technical, commercial or geopolitical factors. In contrast natural gas supplies in Ireland are amongst the least secure in the EU, as Ireland currently has a very high dependence on natural gas imports. All imports are received via Great Britain which is itself set to become increasingly dependent on natural gas imports in the future. Crucially, all natural gas imports to the island of Ireland could, in the opinion of some insurance risk assessors, be totally lost for a period of up to ten days, due to a single incident

One the many benefits of an expanded wind programme would be to reduce this dependency on imported gas, but others, apart from cost savings – increasingly likely by 2010 - include the creation of supporting industries. The value of the latter has been estimated at €1 billion by 2010[3].

This paper examines the economic and technical implications of an expanded wind energy programme, and builds on work already carried out by the Irish Wind Energy Association, Sustainable Energy Ireland and other bodies.

2. WIND ENERGY

2.1 Status

World wind energy capacity doubled every three years from 1990 to 2003, as shown in Figure 1[4]. Installed capacity in 2003 grew by 27% so that total world wind turbine capacity at the end of the year was over 39,000 MW. Germany, with over 15,100 MW, has the highest capacity but Denmark, with over 3100 MW, has the highest level per capita; wind production in western Denmark accounts for about 19% of electricity consumed. At times, the power output from the wind turbines matches the total consumption in Jutland. Other locations with over 1000 MW of wind are Spain, (6600), the United States (6300), and India (1869). Major developments are planned in South America and in Australia it is estimated that wind could be competitive with natural gas by 2010[5].

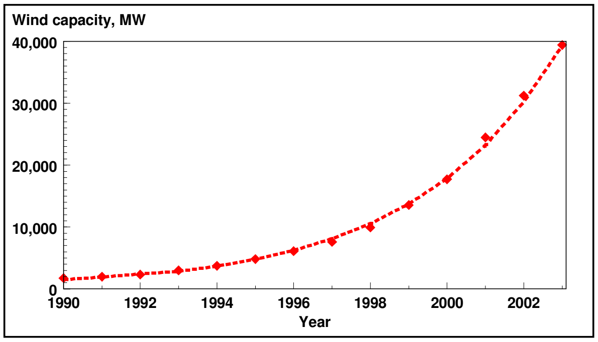

Figure 1 Development of world wind capacity, 1990-2003

2.2 Costs

This expansion of wind capacity has been accompanied by a dramatic reduction in the costs of electricity energy generated by wind. Several studies have examined this trend and have concluded that the "learning curve ratio" -- the reduction in price, per doubling of capacity -- is between 8 and 18%. Since world wind capacity has been doubling every three years, or less, as noted above, this implies that prices have been falling at between 3 and 6% per annum.

In parallel with these reductions in cost, energy productivity has been increasing and the availability is of most wind installations are now in the range 97-99%. One of the factors contributing to improvements in performance and cost has been the trend towards larger wind turbines, and this also seems set to continue, although it is likely to be more focussed on offshore machines. Onshore sizes may level out.

The principal determinants of wind energy generation costs are the installed cost, wind speed and financial criteria. Roughly speaking, developments on sites with wind speeds of 8 m/s will yield electricity at one third of the cost for a 5 m/s site.

An analysis carried out for the IWEA suggest that present-day installed costs in Ireland are around €1090/kW, which appears to be about 10% higher than the current average the world price, as discussed in Appendix 1.

In practice it is rare for all the relevant components of the cost calculation to be explicitly quoted, but there is a reasonable consensus between estimates from impartial bodies. The World Energy Council, for example, suggests €45/MWh[6] for the current price. For the first time, in 2004, the United States Energy Information Administration's "Annual Energy Outlook", suggested that, by 2010, the price of wind would be almost identical with that of gas, at around $50/MWh (€41/MWh).

3 GENERATION COST COMPARISONS

Currently, most plans for future electricity generation involve the use of high efficiency gas turbine plant, so if wind plant is installed in significant quantities in Ireland, it will inhibit or delay the construction of gas-fired plant. Until recently, generation costs from gas were fairly stable, at around €30/MWh. During 2004, however, fossil fuel prices have been rising rapidly and, at the time of writing (October) the oil price is fluctuating around $50/barrel. Gas prices have also followed an upward trend and contract prices in the UK that were placed in June were between 30 and 40% higher than those placed a year ago[7]. Gas futures have been moving steadily upwards for some time, so it is now extremely difficult to make projections of future gas prices. Not only the price, but also the security of future gas supplies is extremely uncertain, which means that there are significant risks in increasing the dependency on this source of fuel[8].

Although the prospects for wind energy are frequently assessed by comparing their generation costs with those of the thermal sources, this approach is only a first step. A more rigorous analysis needs to take into account other factors, some of which enhance the value of wind, whilst others necessitate additions are made to straightforward generation costs. The principal issues that need to be taken into account are: -

- The "external costs" of wind energy are much lower than those of the thermal sources of electricity. These are costs that are not accounted for, such as those due to acid rain damage, and global warming. The "external costs" of wind energy are much lower than those of the thermal sources of electricity. The subsidies provided by governments for fossil fuels are also included within external costs. The issues are examined in Appendix 2. Including the external costs of damage due to acid rain, etc, and at the same time removing coal subsidies would add around €8-19/MWh to the price of gas-fired generation in Europe, more to coal and oil[9]. Although there have been proposals for the "carbon tax" that would, at least qualitatively, partially reflect the external costs of generation from fossil fuels, an Emissions Trading Scheme will now be implemented in the European Union and the implications are taken into account later in this report.

- On the debit side, the intermittent nature of wind energy means that it has to carry the costs of extra reserve, as it increases the uncertainty in matching supply and demand. However, these costs as modest – around €3/MWh with 10% wind, rising to around €4/MWh with 20% wind – as numerous studies testify[10]. This issue is discussed in Section 4.2.2 and estimates for Ireland are discussed in Appendix 1.

- Wind energy, in common with most of the other renewable energy sources, feeds into low voltage distribution networks, closer to the point of use and therefore perhaps has a higher value. On the other hand, wind in remote regions may necessitate grid reinforcements, which arguably must be added to generation costs.

4. THE IMPACTS OF AN EXPANDED WIND PROGRAMME

In the last two or three years, several analyses have appeared which quantify the additional costs (if any) to electricity consumers of increasing the amount of renewables – especially wind energy - in the generation mix. Examples include an analysis for the UK[11], and for Pennsylvania[12]. The UK analysis suggested that the extra cost to the electricity consumer of providing 20% of supplies from wind energy would be about 0.3p/kWh (0.45c€/kWh). In the light of recent gas price rises that estimate is now very pessimistic.

An assessment of the effect on electricity prices of increasing amounts of wind energy depend on the amount and timing of the additional wind capacity, on projections of future costs of wind and gas plant and, crucially, on estimates of the future cost of gas. Each of these is now dealt with in turn and it may be noted that the latter is the most difficult to predict.

4.1 Electricity system data

The starting point for electricity system data is the estimate of generation for 2005 of 28 TWh. This is in line with data used by the IWEA[13]. Thereafter, demand grows at 3.8% p.a. to 2010 (which is in line with the latest estimate of peak load growth by the Transmission System Operator[14]. Beyond 2010, the growth rate is assumed to be 2.3% p.a., so that demand in 2020 is 41 TWh, in line with the IWEA estimate. It is assumed that construction of wind plant takes place instead of the construction of gas-fired generation. This procedure has been used in most of the other studies, cited above. However, it may be noted that wind may also displace peat and coal-fired generation. As the former attracts a subsidy of at least €33/MWh, plus heavy CO2 penalties, plus external costs, the results of this analysis are conservative.

4.2 Wind plant data

4.2.1 Capacity and energy

The key assumptions suggested by the IWEA were:

2010: 2250 MW onshore, 250 MW offshore, total 2500 MW

2020: 4700 MW onshore, 800 MW offshore, total 5500 MW

Assuming a 35% capacity factor, following the Commission for Energy Regulation and a UK study, that capacity would generate 23.4% of Ireland's electricity in 2010, and 41% in 2020. The implications of using different capacity factors were explored in the sensitivity analysis.

4.2.2 Costs

The 2005 installed cost for wind is €1090/kW, as noted in Section 2.1. Wind energy generation costs fell by a factor of over four between 1981 and 1999[15] and there is every expectation that this trend will continue, albeit at a slower rate. Several estimates of possible future costs are reviewed in Appendix 1 and a central estimate of €936/kW has been assumed for 2010 (it may be noted that several wind farms have already been built at this price). Prices for 2020 are inevitably more uncertain and a central estimate of €683/kW has been used.

A sensitivity analysis examines the implications of the installed costs forecast by the European Wind Energy Association being reached in Ireland by 2020 – but not until 2020. No adjustment has been made to the 2005 cost, and no change made to the offshore cost estimates, so this scenario is still conservative when compared with the EWEA assumptions.

4.2.2 Wind variability

There is such a wealth of misunderstanding over this issue that it worth quoting a summary of the views of the UK System Operator, National Grid Transco[16].

"However, based on recent analysis of the incidence and variation of wind speed we have found that the expected intermittency of wind does not pose such a major problem for stability and we are confident that this can be adequately managed…

It is a property of the interconnected transmission system that individual and local independent fluctuations in output are diversified and averaged out across the system. Moreover, we do, and will continue to, carry frequency response such that frequency in contained within statutory limits for specified load and generation events... The interconnected transmission system enables this to be carried out more economically than would otherwise be the case.

We believe that current levels of frequency response are sufficient even if the Government's 2010 goal of 10 per cent of electricity supplies sourced from renewable fuels were all to be met by, say, wind technologies. In any event, should more response and reserve services be required, then our ancillary service market arrangements should encourage their cost effective provision. We do not therefore foresee any significant technical problems arising from accommodating the Government's targets for renewables and CHP by 2010."

NGT have quantified the extra costs of reserve and frequency response for 20% wind as about £2.85/MWh of wind (11). It may be noted that the smaller Irish network needs to carry more “spare” plant – even without wind – and so the acquisition of reserve is unlikely, again, to be a problem.

4.3 Gas plant data

The Commission for Energy Regulation’s (CER) estimate of the installed costs for new CCGT plant in Ireland (€687/kW)[17] for 2005 is very similar to the value of £450/kW used by Dale et al for the UK (11). This includes interest during construction.

Three gas price scenarios have been used:

1. Prices stay constant at the level assumed by CER for 2005, i.e. 30p/therm (UK), which corresponds to €0.52/therm delivered to Irish power stations. This “start price” is used in each scenario.
2. It is assumed that prices increase at 2% p.a., to reach €0.57 by 2010 by 2010 and €0.7/therm by 2020. This broadly corresponds to a scenario used by the IWEA (13), in which the price reaches €0.65/therm by 2010, and is sustained at that level until 2020.
3. Prices increase by 3.5% p.a., to reach 50p/therm (UK) by 2020, or €0.87/therm delivered to Irish power stations.

On 19 October 2004, the time-weighted average price of gas futures for 2006[i] was 36.5p/therm (UK), a price that had moved steadily upwards over the previous 2 months. That is 20% higher than the 2005 price, and the demand-weighted price is almost certainly higher. If prices rise at 3.5% p.a. that price would not be reached until after 2010.

An alternative interpretation of scenario 3 is that it is effectively a "constant gas price" scenario, but with the discount rate adjusted to take account of fuel price risk. A number of studies have drawn attention to this risk and further details are discussed in Appendix 1.

5 COSTS AND SAVINGS TO ELECTRICITY CONSUMERS

5.1 Method of calculation

Wind energy is no different from any other electricity generation option. It has a generation cost, and a value. If value exceeds cost, addition of a new generation source will lower overall system costs, and vice versa. In the case of wind energy, the additional costs of extra reserves must be taken into account. The extra cost of wind energy can be expressed as: -

<u>(Generation cost) + (intermittency costs) - (fuel saving value) - (capacity saving value)</u>

The method of calculation is very similar to that employed by Dale et al (11) for the UK, and by Black and Veatch (12) for the State of Pennsylvania and works through each of the terms in the above expression. Capital costs are expressed as annuities assuming typical plant lifetimes and industry costs of capital and then allocated pro-rata to all electricity generation produced in each of the years from 2005 to 2020. It may be noted that the “fuel saving value” includes the costs of carbon. This enables the total extra yearly cost of various amounts of wind energy to be calculated. The total extra cost per unit of wind energy and the total extra cost per unit of electricity delivered by the system is also derived.

Notes on the “capacity saving value” and “intermittency costs” are included in Appendix 1, and a summary of the Input data for the modelling is included in Table 3 of Appendix 1.

5.2 Estimates of consumer impacts

Some of the results are shown graphically in Figure 2. In the "central case", where gas prices increase at 2% per annum, there is initially a small extra cost to the consumer, which rises to a peak of €0.88/MWh in 2010 – less than 0.1 euro cent/kWh - after which it declines so that by 2020 the saving to the consumer is €3/MWh on each unit of electricity.

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[i] International Petroleum Exchange web site

Given present-day concerns about the "oil price peak", and switching from oil to gas, a 2% p.a. gas price rise may be conservative. Moreover, as noted earlier, the standard method of calculating generating costs for fossil-fuel plant may not properly account for fuel price risks.

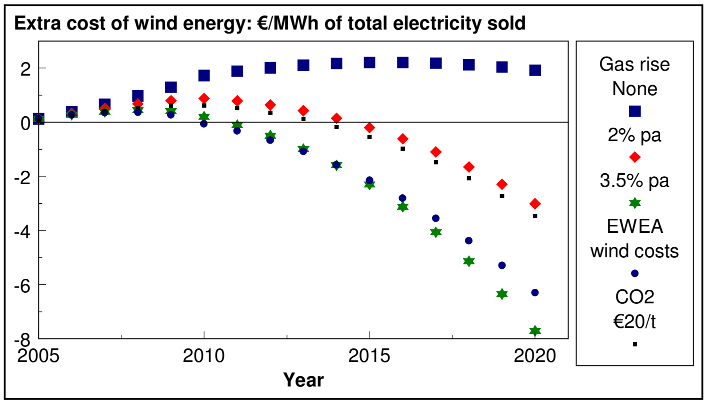

Figure 2 Trends in extra electricity costs to consumers

Assuming that prices rise at 3.5% p.a. takes this risk into account and limits the extra cost to the consumer at around €0.44/MWh (in 2008); by 2020 the saving to the consumer is €7.7/MWh.

The results from a number of other sensitivity studies are summarised in table 1. Only a single variable was changed in each case, with all others held at the "Central Estimate" levels (Table 3 of Appendix 1). So as to summarise the results in a single number, table 5 shows the Net Present Value (at 7% discount rate) of the total cost to the electricity consumer from 2005 to 2020; the Table also includes data from the cases discussed in the previous paragraphs.

The estimates are particularly sensitive to the assumptions about gas prices, wind plant costs and capacity factors, less sensitive to assumptions about balancing costs and the cost of carbon. Even in the case where it is assumed that gas prices do not increase, the extra cost to the consumer reaches just over €2/MWh, which is less than the "external costs" of the fossil sources.

Table 1 Typical results from sensitivity studies

Case **(Items set to base values, except as noted)**	**NPV – cost to consumer, 2005-2020, €million** (negative numbers indicate a saving)
Base (Gas prices rise at 2% p.a.)	***-16***
Gas price rise 3.5% pa	***-452***
Gas prices unchanged, 2005-20	476
Balancing costs increase by 50%	89
Wind capacity factor 34%	66
Wind capacity factor 36%	***-97***
CO2 price €20/tonne	***-97***
EWEA costs reached by 2020 (NB: still conservative, as prices higher than EWEA estimates until that time)	***-410***

6 FUTURE TRENDS

Projections of any kind into the future are subject to uncertainty, and the further ahead, the greater the uncertainty. However, the increasing interest in wind energy, worldwide, is accompanied by an increasing amount of research and development activity. Much of this is focused on easing the assimilation of wind energy into utility networks and so it is highly probable that many of the assumptions made in this analysis are pessimistic. Moreover the growth of wind will be gradual rather than sudden, giving time for systems to evolve and adapt to possible problems. Some of the activities likely to lead to reduced costs for assimilating wind are discussed in this section.

6.1 Improvements in wind forecasting

There is considerable work in progress on improvements in wind forecasting and the emergence of forecasting services, in both Europe and America, testifies to the fact that it is worthwhile improving the accuracy of projected power outputs. A large EU-funded R&D project is currently in progress[18], and a similar utility-funded project is in progress in United States, managed by the Electric Power Research Institute [19].

Commercial forecasting services are also available. AWS Truewind, for example, claims, for one-hour-ahead forecasts, the error is typically 15 to 25% lower than that of persistence forecasts[20].

This work should ensure that the uncertainties associated with balancing the system are reduced and is likely to bring about a reduction in the costs of extra balancing due to the variability of wind.

6.2 Load Management

The intermittent sources of renewable energy, such as wind, are more likely to benefit from load management in the future, although there are potential benefits for all electricity systems. The potential benefits for wind have been examined in one study[21], but such arrangements will be dependent on the agreement of the supplier. In addition, new techniques of demand-side management, currently being investigated in America, may mean that the needs for extra physical frequency response plant may be reduced, with consequential reductions in cost[22].

6.3 New designs of gas turbine

In most electricity systems, part-loaded coal-fired plant, or open-cycle gas turbines, are mostly used to provide spinning and standing reserve, respectively, so the prospect of high levels of gas generation raises question as to where the former may be sourced in future – irrespective of whether wind is deployed or not. With appreciable amounts of wind, more stops and starts on the reserve are likely and so the likely availability of a new generation designs of aero derived open cycle gas turbines will possibly lower the costs for extra reserve that have been used in this paper. The plant has an output of 100MW, with an efficiency of 44%, and start up time (0-100 MW) is 10 minutes[23]. Capital costs are expected to be around €350/kW for sites with fully developed infrastructure e.g. existing power stations, due to be decommissioned. This type of unit may be the ideal complement to wind power at high penetration levels (8) and their extensive utilisation, by 2015, as opposed to additional CCGT plant, could reduce costs significantly.

6.4 Transmission issues, including construction of a link to Wales

The high voltage transmission system in Ireland is extensive but weak. This is because the population and demand centres in Ireland are predominantly located along the coast and also as Ireland's energy requirements were traditionally imported by sea

Thus it was generally possible to locate power stations near the demand centres, minimising investment in transmission lines and high capacity circuits were generally not specified. As a result ESB's transmission network predominantly consists of single circuit lines with a single conductor per phase. In contrast in the UK, the HV network is predominantly constructed using double circuit multi conductor/phase lines, with a much higher circuit ratings.

Because of these differences the HV transmission system in the Republic has proportionately many more circuits and is thus much more extensive than in Northern Ireland or Scotland, where, in the Highlands and Islands there are extensive areas with very good wind regimes, but no access to the HV transmission system and little prospect of gaining access, given the opposition to new lines in scenic areas.

In contrast in Ireland there many areas with good wind regime relatively close to the existing transmission system and even when transmission constraints are taken into account analysis indicates that with proper site selection up to 3000MW of wind powered generation could be connected to the existing or planned transmission system.

In addition the present plans to provide additional north-south interconnections and 2×500 MW interconnections to South Wales will require the development of new transmission corridors in Ireland. Analysis of the transmission network indicates that if consideration is given to wind power development needs in selecting the new corridors and network connection points for interconnection the development of significant additional wind power capacity could be undertaken without further significant transmission system reinforcement.

7. CONCLUSIONS

At a time when all fossil fuel prices are at record levels, and subject to considerable uncertainty in the future, the availability of some of the best wind resources in Europe, if not the world, is a considerable attraction for Ireland.

Although wind energy generation costs are presently more expensive than those from gas-fired generation on a strict cash basis, that is likely to change, through higher gas prices, and/or through reductions in the cost of wind energy plant. However, it must be remembered that the thermal sources of generation are not held accountable for their external costs, many are heavily subsidised, and the risk costs are ignored. The modest extra costs to the consumer associated with wind energy development are far less than these costs and subsidies. However, the consumer does not see these costs because they fall on both citizens and taxpayers. The introduction of the European Emissions Trading Scheme and the planned carbon tax will only partly correct this.

This study examines the costs implications if wind were to contribute 23% to electricity consumption by 2010 and 41% by 2020. Only if gas prices remain stable after 2005 for another 15 years would there be a net cost to the consumer. In what is considered to a be a realistic, probably conservative, scenario, with gas prices rising at 2% p.a., the extra cost to the electricity consumer peaks at under 1 euro cent/kWh, before falling away, due to the combined effects of rising gas and falling wind prices. The net present value of the cost to consumers from 2005 to 2020 is negligible, and translate to a saving of €452 million if gas prices rise at 3.5% p.a. Similar savings will be realised if wind plant costs fall more rapidly than assumed in a cautious “central estimate”.

With the levels of wind energy penetration foreseen in this study, it is likely that oil, coal and peat generation will be displaced, implying that the costs quoted – based on the gas build that is deferred - are a very conservative estimate. While support will still be required to develop wind energy in the early years, the additional cost to the consumer will be far less than the overall saving in subsidies, carbon costs and penalties and external costs. With realistic assumptions about the likely gas price rises and reduction in wind energy costs, Irish electricity consumers would be likely to reap benefits from the introduction of a wind energy programme before 2010.

The introduction of more wind into Ireland is unlikely to give rise to technical problems. In the short term, although Ireland is virtually an isolated system at present, numerous studies have suggested that the variability of wind does not pose any operational difficulties, at least with modest wind energy penetration levels - below around 20%. In the longer term, the recent confirmation of government interest in the construction of an interconnector to Wales is likely to bring benefits to the Irish electricity system and will also ease the assimilation of increasing amounts of wind energy. Worldwide research into better wind forecasting and sophisticated methods of Demand-side management are also likely to mitigate any problems associated with assimilating large amounts of wind energy in the future.

APPENDIX 1

BACKGROUND INFORMATION: GENERATION COST AND VALUE DATA

A1.1 Wind Energy

A1.1.1 Present-day costs of wind energy

The principal determinants of wind energy generation costs are the installed cost, wind speed and financial criteria.

Installed costs: A recent analysis of installed costs of wind farms, worldwide, as reported in the Journal "Wind Power Monthly" suggested a weighted average price of $1256/kW (almost exactly €1000/kW), with lower and upper deciles of around $900/kW and $1400/kW, respectively. There are fewer data for offshore wind farms and the range of costs is $1400/kW to $1800/kW. These figures provide the basis for the installed costs used to derive the generation cost estimates shown in figure 3.

Wind speed dependency: Strictly speaking, all estimates of wind energy generation costs should come with a wind speed attached. In practice, most estimates are relevant to the wind speeds in the country concerned; in most places this means hub height wind speeds between 7 and 9 m/s. Danish wind speeds are towards the bottom end of this range, German wind speeds are mostly lower -- around 6 m/s - and British and Irish speeds are towards the top end of the range. The exact relationship between wind speed and energy production depends on machine characteristics, but a generalised relationship can be derived based on an analysis of a number of performance characteristics from commercial wind turbines.

Financial criteria: these vary widely and depend, to a large extent, on whether "public sector" or "private sector" criteria are relevant. Public sector test discount rates are mostly in the range 4% to 6%, and depreciation periods may coincide with plant lifetime - up to around 20 years. Private sector test discount rates are mostly in the range 8-12%, with depreciation periods rarely exceeding 15 years.

The generation cost estimates in figure cover a range of wind speeds between 6 and 9 m/s and the installed costs discussed above. The test discount rate is 8% and the depreciation period 15 years.

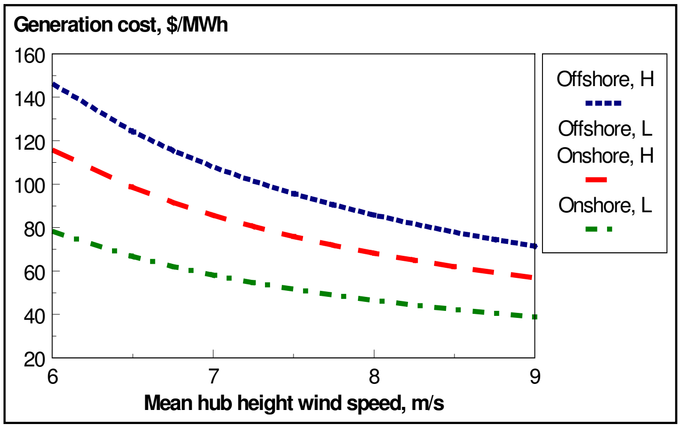

Figure 3 Estimates of wind energy generation costs[24]. (H is upper decile cost; L is lower decile cost, see text).

A1.1.2 Future costs of wind energy

Installed costs of wind energy have fallen rapidly during the past 20 years and generation costs have fallen even faster. This is because there have been significant improvements in energy productivity and because the bigger machines intercept higher wind speeds. It is unlikely that the productivity improvements will be as significant in the future.

There have been numerous studies of "learning curve" effects for wind turbines. "Learning curve ratios" are normally expressed as the reduction in cost that is achieved for each doubling of output. It is a widely used concept and projections of future wind energy costs are often based on this, at least in part. There is, however, a growing realisation that a key factor that will influence future costs is the growing tendency towards large wind farms -- especially offshore. These will realise savings in several areas, especially grid connection costs, construction costs and turbine costs -- through the ability of developers to negotiate discounts for large quantities.

Projections of future costs use a mixture of "learning curve" theory and engineering assessments in order to arrive at their estimates. A number of these are tabulated in table 2, below. Some quote projected installed costs, others cost ratios, and others generation costs. As the capital costs of wind energy plant dominate the generation cost calculations, installed cost ratios and generation cost ratios are broadly comparable.

Table 2 Estimates of future wind costs

Source	2010/2020 cost (€/kW)	2010 cost/2001 cost	2020 cost/2001 cost	Notes
EWEA[25]	451/363			Installed costs onshore
Forum for the Future[26]		0.77	0.70	Installed cost onshore
		0.63	**0.58**	Installed cost **offshore**
Report for US DoE[27]	443/590		0.69-0.92	Installed costs onshore
UK, PIU[28]			Down to about 0.6	*Generation costs* onshore
			Down to about 0.4	*Generation costs* **offshore**
UK, DTI[29]		**0.5-0.7**		*Generation costs* **offshore**
Garrad Hassan[30]		0.89	0.81	Installed cost onshore, ref 2003
		0.73	**0.57**	**Installed cost offshore, ref 2003**
Australian study[31]		0.63	0.55	*Generation costs* onshore

In practice, there is probably greater scope for cost reductions offshore than onshore and so slightly different parameters are probably appropriate. Data in the Table suggest the range of estimates for onshore installed costs in 2020 is quite wide. The choice of a mid-range cost is somewhat subjective; the mid-range value of $600/kW (€500/kW) is possibly optimistic in the light of the most recent estimate (from Garrad Hassan). A more conservative estimate of €680/kW was used by Dale et al (11) in the UK, and is also used as the central estimate for this analysis. Estimates for future wind costs were derived assuming a constant "learning ratio". The corresponding estimates for gas -- where the change between 2005 and 2020 is expected to be much less - were based on linear interpolation.

For offshore, there is a better consensus, with most studies suggesting the 2020 cost will be around 60% of the present-day cost. As the latter is about €1600/kW, this suggests the 2020 price may be about €960/kW.

Other key parameters are the operation and maintenance costs and the capacity factor of the wind plant. The analysis assumes that operation and maintenance costs will fall in the same way as capital costs.

A uniform value of capacity factor (35%) has been assumed throughout, although there may be a case for using a higher capacity factor for offshore wind. The estimate is in line with the value used by the CER (40).

A1.1.3 Capacity credit

The capacity credit of any power plant may be defined as a measure of the ability of the plant to contribute to the peak demands of a power system. The thermal plant that wind displaces depends on the capacity credit. The issue was also explored in an analysis for Sustainable Energy Ireland[32], where it was shown that the latest estimates from ESBNG were in good agreement with other estimates for the Irish electricity network. These results have therefore been used in this analysis. The capacity credit of 1000 MW of wind is about 300 MW, of 2000 MW, about 400 MW and of 3500 MW of wind about 500 MW.

A1.1.4 Extra balancing costs

These were explored in an analysis carried out for Sustainable Energy Ireland (32). More recently, additional estimates have been generated by a more detailed study[33], indicating slightly lower costs. The costs amount to around €1.5/MWh with 10% wind energy, rising to just over €2/MWh with 20% wind energy.

An ESBNG[34] report expresses concerns over the number and costs of extra start-ups and stops of load-following plant. Analysis of Danish data confirms that the standard deviation of demand fluctuations, net of wind, increases as the amount of wind increases, so that extra activity may be expected. However similar effects in Britain were costed in a system study[35], which was taken into account when estimates of extra balancing costs were made for Ireland. It may be noted that ESBNG seem to have based their conclusions on limited dataset of wind fluctuations.

The ESBNG report includes a “Capital Cost for Extra Capacity”. No other utility study has used this concept, which was not found in a recent major review of intermittency issues[36]. The concept appears to be based on the assumption that, at times of peak demand, 100% of the rated output of the wind plant is expected to be available and so, if the capacity credit is 35% of the rated output, 65% of the rated output must be provided as backup. This reasoning is flawed for three reasons: -

- No plant is 100% reliable. The average capacity factor of base load coal or gas, for example, is about 75-85%. The reasoning put forward demands, therefore, that such plant has 15-25% “extra capacity”.
- The rated capacity of the wind plant is of little interest to system operators in the context of assessing a desirable plant margin (the margin between total plant capacity and expected maximum demand). What matters is the amount of wind likely to be available at times of peak demand. Every authoritative study of the electricity networks in the UK and Ireland has concluded that this quantity - the "capacity credit" - roughly corresponds to the average output of wind plant during the first quarter of the year (when peak demands normally occur). On this basis, 1000 megawatts of wind has a capacity credit of about 400 megawatts.
- The percentage requirement is independent of the amount of wind

It may be noted that the “apparent” plant margin goes up with wind on the system, but no *extra* gas plant needs to be built – apart from the modest amounts needed for extra balancing.

A1.2 Generation costs for thermal plant

Gas-fired generation has been the predominant source of new generation since 1990, and so it may be assumed that renewables will 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.

CER’s estimate of the installed costs for new CCGT plant in Ireland (€687/kW) is very similar to the value of £450/kW used by Dale et al for the UK (11). 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 €640/kW. US DoE do not anticipate any change in operation and maintenance costs and so the current figure for these, plus local rates that are relevant to Ireland, of €60/kW/yr has been used. Availability has been taken as 90% in each case.

A1.2.1 Gas prices

At the present time (October 2004) energy prices are in a state of turmoil, so that the estimation of future prices is very difficult. CER's estimate for 2005 gas is €0.52/therm, which corresponds to €34.8/kWh from a CCGT with 56% efficiency. This price includes the gas transportation costs for delivery to the power stations. With little expectation that prices will fall, a "Low gas price scenario" assumes prices stay constant at this level. The IWEA has suggested an alternative scenario, in which the price reaches €0.65/therm by 2010, and is sustained at that level until 2020. This has been taken as the basis for the central estimate, although a minor modification has been made by assuming prices increase at 2% p.a., giving a slightly lower price in 2010, slightly higher in 2020.

Current prices (October 2004) in both Europe and America are significantly higher then levels predicted only a few months ago. In America, for example, futures at the "Henry Hub" are now almost 50% higher then the *delivered* prices to US electricity generators projected by the Energy Information Administration about six months ago. Similarly, a recent report by respected consultants Oxera[37] suggests that UK prices are "trading above 30p/therm for both 2005 and 2006", and this is consistent with recent data on the International Petroleum Exchange website. Allowing for onward transmission to Irish power stations, this suggests that the CER estimate for 2005 is robust.

An alternative approach to modelling future electricity prices from fossil fuels, advocated in a number of papers by Awerbuch[38], is to use a different discount rate to work out the Net Present Value of fuel costs over the life of the power stations. This has a significant impact on the price of gas-fired generation, as it pushes it to between $50/MWh and $73/MWh, depending on the precise approach and the discount rates, which are adopted. Awerbuch suggests using discount rates between 2.1% and 6%, and his "central case" uses 3.5%. As the "high gas price" scenario used here suggests gas prices will rise at 3.5% p.a., and the discount rate is 7%, this case effectively uses the procedure suggested by Awerbuch, as the net discount rate – based on present-day gas prices – is 7-3.5, or 3.5%.

A1.3 Input data for estimates of extra costs

Table 3 summarises the input parameters used for the analysis, for both wind and thermal plant, together with the sources of data, if not identified above.

Table 3 Input parameters for analysis - central estimates

					SOURCE
Date		**2005**	**2010**	**2020**	
Wind Capacity: total	MW	585	2500	5500	IWEA, Feb 04 (13)
onshore	MW	560	2250	4700	Onshore/offshore split: IWEA
offshore	MW	25	250	800	
Capacity factor		0.35	0.35	0.35	Figure used by Dale et al (11) for UK
COSTS					
Wind					
Capital, onshore	€/kW	1090	936	683	2005: Bacon[39], 2020: Dale et al (11)
- offshore	€/kW	1680	1370	900	As above
O&M - onshore	€/kW/yr	32	27.5	23	
- offshore	€/kW/yr	74	60.3	36	

Gas					
Plant cost	€/kW	687	657	600	2005: CER (17); 2020:Dale (11)
O&M	€/kW/yr	60	56	50	
Fuel – gas price	€/therm	0.52	0.57	0.70	2005: CER; 2020: IWEA (13), see text
CO2 cost	€/tonne	10	10	10	IWEA
Test discount rate	%	7	7	7	
Depreciation – all plant	yr	15	15	15	

With these assumptions, wind would deliver 23% of electricity by 2010, and 41% by 2020.

A1.4 Sensitivity tests:

Table 4 summarises the additional data used in the sensitivity analyses. As the data for wind are believed to be conservative -- wind farms have already been built for the installed cost assumed for 2010 -- only a "lower cost" alternative has been used.

In the case of gas, the fuel price dominates the assessments. A constant gas price has been taken as a "low gas price" scenario, and a "higher gas price" scenario assumes a 3.5% per annum increase. However, in the light of the arguments put forward by some economists, this may be construed as a "constant gas price" assumption, but with the discount rate adjusted to allow for risk, as discussed in section A1.2.1.

Table 4 Principal variations used for key parameters

					Source
Date		**2005**	**2010**	**2020**	
Costs					
Wind – lower cost					
Capital, onshore	€/kW	1090	809	447	EWEA (25); geometric progression from start value assumed
- offshore	€/kW	1680	1213	630	In discussion with IWEA
Fuel – gas price					
low	€/therm	0.52	0.52	0.52	(Constant)
high	€/therm	0.52	0.61	0.86	Increase of 3.5% p.a., see section 3.3.1
CO2 cost (High)	€/tonne	20	20	20	IWEA

APPENDIX 2 EXTERNAL COSTS FOR FOSSIL FUELS IN IRELAND

The European Union's proposals for a carbon tax were a move towards a proper internalisation of the external costs of fossil-fuelled generation. As governments were unwilling to accept the increase in electricity prices that would have followed, the proposals are unlikely to proceed, although the Emissions Trading

Scheme will impose small extra costs on generation from fossil fuels. Subsidies to renewable energy are seen as a less contentious way of putting renewable and fossil generation on an equal footing. As renewables in general account for a much smaller proportion of total generation, the impact on electricity prices is less.

In Ireland, the situation is further complicated by the existence of the "Public Service Obligation" Levy, which covers both final and renewable energy sources. Table 5 summarises the present situation and shows that the present arrangements give more support to thermal than to renewable sources, with the external costs of the former ignored.

Table 5 External costs and subsidies for electricity in Ireland

Description	Generation, TWh (approx)	Cost €/MWh	Cost, €M/yr	Comments
Coal, oil and gas, external costs (9)	20	>10	>200	Not accounted for in electricity prices
PSO, thermal, extra cost[40]	3	33.8	90	Cost to consumers
PSO, AER, extra cost	1.2	10.1	12.3	Cost to consumers

It may be noted that the level of subsidy to renewables, through the PSO, is much less than the explicit and implicit subsidies to fossil generation.

APPENDIX 3 OTHER (UNQUANTIFIED) BENEFITS AND COSTS

A3.1 Embedded generation benefits

The principle that small-scale generation may save transmission and distribution losses (and charges) is now established and additional (small) payments may be made for voltage support, reactive power and other ancillary services. It is important to recognise, however, that concentrations of embedded generation can increase distribution losses in rural areas where demand is low and so may incurs costs rather than benefits. These are complex issues, which vary both regionally and locally, but a study of a ten-machine, 4 MW wind farm connected into an 11 kV system in Cornwall, England has provided valuable information on the impact on a distribution system[41]. The study examined a range of issues and concluded "the wind farm caused surprisingly little disturbance to the network or its consumers". In particular: -

- Voltage dips on start-up were well within the limits prescribed. There were no problems with flicker during any operating conditions
- During periods of low local load, the output from the farm was fed "backwards" through the distribution network, but no problems were reported.
- Reduced activity of the automatic tap-changers at the adjacent 33/11 kV transformers was significant and would lead to lower maintenance costs.

A3.2 Impact on gas prices

One further factor that is difficult to quantify is the impact that wind may have on gas prices, by reducing the demand. Taking this into account, the Union of Concerned Scientists has estimated that increasing the generation from wind and other renewables in America from 2% to 20% by 2020 would reduce gas used by 6% and save consumers nearly $27 billion[42]. Although the reduced consumption in Ireland, alone, is unlikely to have a significant effect, increased use of renewable energy in Europe as a whole may have an impact in due course.

A3.3 Security of supply benefits of wind

Ireland is the EU country with the lowest ratio of natural gas storage capacity to average daily natural gas imports, but ESBNG's assessment of electricity supply security apparently took no account of primary energy security, other than wind, and the fact that Ireland has already the third highest dependence on natural gas fired generation in the EU

It may be noted that over 600MW of existing natural gas fired generation is not equipped with or cannot operate on standby liquid fuel supplies, whilst another 600MW of natural gas fired generation is only equipped to receive liquid fuel deliveries by road tanker and difficulties have been experienced in mobilising the necessary tankers in the past. The remaining 750MW of natural gas fired generation can receive standby distillate supplies by sea, but the shipping trade have advised that the availability of clean product tankers in these waters is limited and mobilising the tanker capacity required to replace a total loss of natural gas imports could prove difficult, as power station natural gas consumption in Ireland, North and South, in 2005 will equate to 10,000 tonnes of distillate per day, in energy terms. This is very similar to the combined total daily consumption of petrol and diesel in the South in 2001.

Putting a price on security of supply is not easy, but a recent UK report has looked at the implications for security of electricity supplies as the dependency on imported gas increases[43]. The study looked at the political and technical risks of interruptions to gas supplies. Drawing on data from the insurance market, the study estimated the possible number of supply interruptions and the implications as far as electricity generation shortfalls. In order to translate these to monetary estimates, it was necessary to assume a "Value of Lost Load". This is a fairly standard concept in electricity studies, although the exact levels vary. The study used a value of £3000/MWh (around €4500/MWh). When comparisons were made with a reference case, (6500 MW of wind), the security of supply benefit, in a system with 14,200 MW of wind was £5.1/MWh, or around €7.6/MWh. Although this particular value may be specific to the United Kingdom, and to the particular scenarios examined, it may be relevant to Ireland, in view of the common source of most gas supplies.

A3.4 Constraints

It may be necessary, on some occasions, to “constrain off" wind plant if there is a risk to the stability of system operations. This is most likely to occur at times of high wind power output and low consumer demand, when a large drop in wind power output might impose demands on the thermal plant that might be expensive or difficult to meet.

This issue has not been examined in detail in Ireland, but one way of looking at the question is to note that the present-day Irish system copes with the minimum demand, and then argue that this minimum level, net of wind, should not change, as the amount of wind increases. Making use of data from western Denmark, in the year that wind accounted for 19% of consumption, around 9% of the wind energy should have been constrained off to ensure that the minimum demand, net of wind, did not dip below the minimum consumer demand. However, when operation of the system with 10% wind was modelled, only 1.3% of the wind energy needed to be constrained off.

Another indication that the effects of constraints will be small comes in a recent UK study, already cited, (35). This examined various scenarios, with up to 27% wind energy, and the constraints at this level only added 3% to the extra balancing costs.

Advances in wind forecasting, plus the growth of DSM, means that it is likely that these figures are conservative. Apart from this, it is quite likely that the minimum load can be allowed to drop slightly below the current level of minimum consumer demand.

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