# Technical and economic potential of renewable energy generating technologies: Potentials and cost reductions to 2020

# The technical and economic potential of renewable energy generating technologies: Potentials and cost reductions to 2020[1]

## Contents

1. Introduction

2. Technical and economic potential
    - terms and definitions
    - existing DTI/ETSU analysis

3. Theoretical approaches to estimating future costs
    - engineering assessment
    - learning curves

4. Cost reduction potentials for the leading renewable generating options

5. Conclusions
    - Cost reduction potentials of key renewable technology options

*Appendix*

Technological Progress and Learning Curves

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[1] Lead authors on this working paper were Jake Chapman and Robert Gross

# 1. Introduction

This Paper is concerned with the economic and technical prospects for renewable energy generating technologies. Other technologies are discussed in the accompanying working papers on energy efficiency, nuclear, transport and energy systems in 2050[2].

The central focus of this paper is to assess the potential for reducing the costs of the main renewable energy options for the UK. Over the timeframe under consideration in the Energy Review there is considerable potential for innovation and technology development, much of which is impossible to foresee with any accuracy, some not at all. Nevertheless, as we discuss below, cost reduction is closely correlated with the extent of deployment and application of a technology; as cumulative production rises costs fall, a relationship that may be modelled and explored empirically using 'learning curves'. Engineering assessment of technological maturity and potential for further development can also provide valuable insights and information, particularly where market experience is limited.

Both learning curves and engineering assessment may be applied to all technologies and the relationship between cost and production has been shown to apply in a wide variety of applications. However, because the markets for renewable energy are currently very small, with significant potential for expansion, the potential for cost reduction is large – if the application of these technologies is able to expand.

Projecting costs out to 2050 would be a perilous task. Very few technology-focussed scenarios look out to 2050 and detailed work on costs and economic potential does not go beyond 2020 or 2025 (for short-hand, '2020' is used to refer to this 20-25 year time horizon). The reasons for this are fairly obvious: firstly it is impossible to anticipate the full range of social and technological innovations likely in such a long time period – extrapolation from current trends is not appropriate; secondly, such a long timeframe is unnecessary for most policy and commercial purposes; finally for some technologies there is little evidence of the rate at which costs have historically fallen because market experience is too limited, in such cases even 20 year projections are challenging.

This paper therefore takes a quantitative view to 2020 – and provides estimates of cost reduction potential. Attempts have been made to apply learning curves to all the options that appear to offer greatest technical potential – PV, wind, wave and energy crops. The PIU team built a spreadsheet model of the relationship between learning rate, cumulative production and market growth based upon data from a number of sources and using IEA methodology. However, analysis based upon learning curves has only proved practicable for those technologies with sound and unambiguous market development and cost reduction data – wind and PV. Cost reduction potentials are discussed more qualitatively for other technologies using engineering assessment and limited use of learning curves.

Beyond 2020 it is necessary to take a largely qualitative view of the issues and opportunities that can be foreseen. Uncertainties become too large to facilitate detailed and quantitative projections.

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[2] Also available from the PIU website.

## 2. Technical and economic potential

A large number of studies have estimated the future potential of renewable energy technologies, both in terms of the technically feasible energy output that could be secured from each technology type, and the economic potential, taking into consideration cost and other limiting factors.

### *2.1 Terms and definitions*

Precise terms and definitions differ, but it is important to distinguish a number of key concepts, most of which are common to all studies:

*Available resource* refers to the total amount of different forms of renewable energy available for extraction – for example the energy in ocean waves, or solar insolation levels. For several technologies (essentially solar, wind, tidal, wave and biomass), UK available resource is very large indeed.

*Technical potential (also referred to as accessible resource)* refers to the amount of energy that might be extracted from the available resource, using known technologies (note that for future technologies judgements are required, for example about conversion efficiencies – will they improve, how much?). Again, for a number of technologies, technical potentials are very large – taken together they exceed UK primary energy consumption several times over.

*Practicable potential (also referred to as practicable resource)* refers to the amount of the technical potential that might reasonably be accessed, taking into account various technical and physical limiting factors such as competing land (and ocean) use and often includes further limitations, such as electricity grid and system constraints. A closely related concept (definitions of terms do differ) is *accessible potential*. Practicable resource is more difficult to assess in the long term, since many constraints may change over time as technologies progress, or reflecting different political/societal priorities (affecting land-use priorities for example). For the latter reason, it also tends to show significant variation between studies in different parts of the world.

*Economic potential* refers to the amount of accessible potential that is economically viable, given current technology, or with future, better (and cheaper) technologies. Economic potential depends upon the cost of alternative/competing energy sources, which for the UK generally means conventional means of generating grid electricity (though some renewables can also provide heat, and there are some niche markets such as remote telecommunication/navigation where the electrical alternative is not grid power). It is important to note that policy may influence both the development of renewables and the cost of conventional competitors – for example though a carbon tax.

### *2.2 Existing Analysis*

Analysis of the full range of renewable resources available in the UK was undertaken for the DTI by ETSU, (DTI 1994) which synthesised studies of individual technologies commissioned for the DTI New and Renewable Energy Programme. This work was updated for the DTI review of renewables policy in the UK in 1998 (DTI 1998). This work forms the starting point for our discussion here. The main findings in terms of estimates of technology potentials for 2025 are summarised in table 1.

**Table 1. DTI estimates of Resource and cost in 2025 (derived from DTI 1998)**

| Technology | Cost* p/kWh | Economic potential at this cost* TWh/yr | Technical potential TWh/yr | Practicable potential TWh/yr |
|---|---|---|---|---|
| Building integrated photovoltaics (BIPV) | 7.0 | 0.5 ** | 266 | 37** |
| Offshore wind | 2.5 - 3.0 | 100 | ~3500 | 100 |
| Onshore wind | <3.5 | 58*** | 317 | 8**** |
| Biomass (energy crops)## | 4.0 | 33 | ‘large’ | ‘large’ |
| Wave | 4.0 | 33 | 600 + | 50 |
| Tidal stream# | 7.0 | 1.8 | 36 | 1.8 |
| Small Hydro | 7.0 | 1.8 | 40 | 3 |
| Waste technologies: MSW (municipal solid waste) Landfill gas | 7.0 | 6.5 | 13.5 | 6.5 |
|  | 2.5 | 7 | 7 | 7 |

This table is an interpretation and simplification of the DTI analysis, therefore some caution is needed in interpreting these figures:
‘Technical potential’ here is termed ‘accessible resource’ in the DTI study and practicable potential is termed practicable resource. This is in order to convey that all figures are for potentials – potential energy output, not available resource input.
* ETSU for the DTI, derive ‘resource cost’ curves for all technologies, that increase with cost, in most cases up to a maximum level at which external (practicable potential) constraints cut in. The costs quoted are those at which this maximum level of deployment would be achieved. The exception is BIPV, where only the potential at less than 7p/kWh is included, significantly larger potential would be available at higher cost.
** BIPV practicable potential is limited by assumptions about penetration rate into new buildings, economic potential to even lower penetration of those new buildings with potential for offset building costs.
*** Assumes minimal constraints due to planning, network and build rate. But…
**** Assumes constrained build rate and no network reinforcement – hence the somewhat counterintuitive result that economic potential is higher than practicable potential.
# Tidal stream devices exclude large barrages, ruled out by the DTI on capital cost and environmental grounds. Practicable potential/resource is not provided in the study for this technology type
## Assessment restricted to energy crops for the purposes of this analysis for reasons discussed below, additional contributions are assessed in the DTI work – from forest and agricultural wastes and residues, and from other biodegradable wastes.
The DTI assessment also includes passive solar design and solar hot water, although important these are dealt with in the paper on energy productivity because of the close overlap with building efficiency. For similar reasons we also deal with ground source heat pumps in the energy efficiency paper.

All figures quoted are based upon 8% discount rate.

### *2.4 The need for further assessment?*

The DTI work on renewable energy provides much in the way of preliminary work for assessment technology potential to 2050 and is the start point for this analysis. The estimates of technical potential are used throughout – with the caveat that such numbers are inevitably uncertain, estimating technical potential turns upon many assumptions, and other studies have produced different (and in many cases much larger) estimates. It is particularly notable that different assumptions about land and sea space available for energy crops and offshore wind have increased these estimates to 140 TWh/yr and 900 TWh/yr respectively (Matthies et al.1995, Bauen 2000). Nevertheless it is clear that those technologies that offer the most significant long-term potential in the UK are wind, wave and tidal stream[3], solar PV[4], and biomass energy crops – and these are assessed in detail in this analysis. All of these technologies have very large potential and this conclusion is all that is required at this early stage in their development. The other technologies may also have a significant role to play through niche markets, in meeting other policy objectives (such as waste management) and in expanding awareness of renewable energy.

Assessment of economic potential in the long term requires additional work to augment the DTI analysis, in particular a more detailed assessment of long-term cost reductions is required. The terms of reference of the DTI study did not require an in-depth analysis of cost reduction trends and potential, even to 2020, and certainly not beyond. As a result, the study takes a relatively simplistic, engineering assessment approach to future cost reductions, and the amount of attention given to future costs differs between technologies within the assessment. In addition some technologies, most notably PV, only begin to become cost competitive at the very end of the DTI assessment period but have considerable potential thereafter if cost reduction trends continue. A number of other studies have considered long-term cost reductions, and provide additional insights.

In assessing future costs, the potential for innovation, and technology and market development to drive cost reductions is central. Different studies take different approaches to assessing this role of innovation. In order to appraise potential future costs, we start with an assessment of the main methodologies for estimating future cost reductions.

## 3. Theoretical approaches to estimating future costs

Two basic types of approach to the assessment of future costs of energy and other technologies may be identified: The first may be termed ‘engineering assessment’; the second the ‘learning curve’ approach. However it is important to note that they are not ‘competitors’, indeed their strengths and weaknesses are complementary.

### *Engineering Assessment*

This approach is based upon engineering assessments of technology status and potential. Typically, assessment of technologies places them on a spectrum that ranges from ‘mature’ to ‘emerging’. In simple terms, mature technologies are those that are well established and near the limit of incremental technological development. Emerging technologies, by contrast, are those with considerable potential for further development and cost reduction through innovation.

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[3] The DTI figure for economic potential for tidal stream is based upon analysis of a limited number of sites. Whilst the potential resource is large there is limited data on this technology. For the purposes of this paper we assess tidal stream technologies alongside wave energy.

[4] Restricted to BIPV for the purposes of this analysis as this is likely to be the only practical option for power generation in the UK

In order to assess technology for ‘maturity’ what is sometimes termed ‘technology stretch’ may be identified. This refers to the potential for further technological development and refinement – for continued innovation. Technology stretch may be differentiated by sub-systems or components and is based upon detailed assessment of potential for refinement and development of the technologies themselves, and of manufacturing processes. Cost reductions already achieved in closely related technologies, or those using similar production techniques, are often used as a ‘benchmark’ against which potential cost reductions may be assessed. In all cases such an approach relies upon expert assessment of technological potential.

Potential for continued market growth is often used alongside engineering assessment, and potential for cost reductions through economies of scale assessed. As markets for mature technologies also tend to be well developed and exploited, such economies tend to be limited (this is not always the case – for example where a technology is transferred to a new application or geographical location).

The main advantage of the engineering assessment approach is that it need not rely upon previous trends in cost reduction – that may turn out not be repeatable, or (perhaps more importantly for a number of new energy technologies) are not yet available because market experience is very limited. The main disadvantage is that engineering assessments based on expert opinion can differ, and may be open to interpretation and manipulation. Nevertheless they are an important complement to the ‘empirical’ approach to which we now turn.

### *Learning curves*

The main alternative to engineering assessment for assessing potential future cost reductions is so called learning, learning by doing, or experience, curves. The energy policy applications of learning curves were recently examined at length by the International Energy Agency (IEA 2000), the findings are discussed in more depth in Appendix 1. Learning curves are derived from empirical data – on cumulative production and cost[5]. Evidence from a very wide range of technologies and sectors demonstrates a clear relationship between production and cost; put simply, as cumulative production increases, costs fall. This ‘simple’ relationship should not be interpreted as underplaying the complexity of the drivers of cost reduction – technological innovation, economies of scale, improved utilisation of labour and capital interact in complex ways. However the core conclusion that flows from the phenomenon of learning curves is that most ‘learning’ and cost reduction come through production and market experience.

If cumulative production and unit cost are plotted on a log/log scale (log cost against log cumulative production) the learning curve appears as a straight line as shown in Figure 1 below.

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[5] In fact, price and cumulative sales are normally used as proxies for cost and cumulative production.

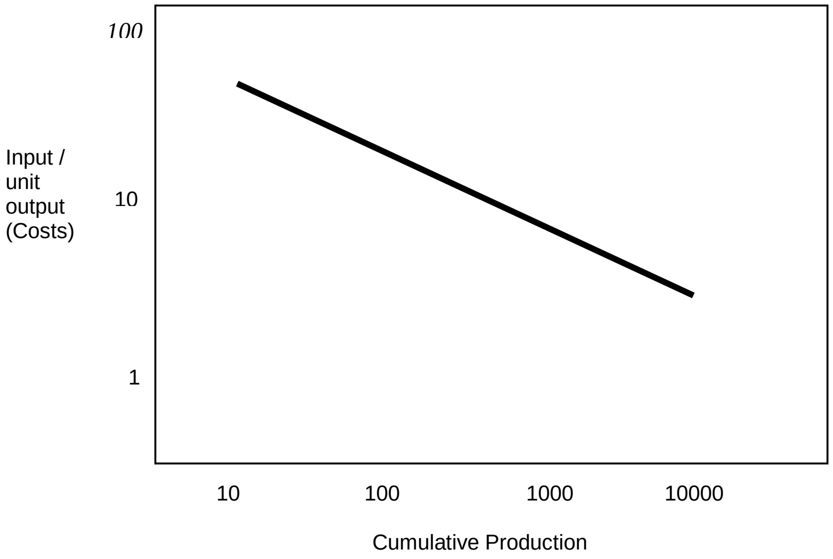

**Figure 1. A learning curve on a log-log plot.**

The slope of the curve gives us the relationship between cumulative production and cost, which may be presented in a number of ways. The measure that we will focus upon here is the 'learning rate' – the percentage cost reduction that occurs with every doubling of cumulative production. Learning rates vary by technology and at different stages of development of a given technology – tending to be 'faster' in the early stages. However, typically, for industrial products, the learning rate is in the range 10 to 30%, which means that for each doubling of cumulative production, costs fall by between 10 and 30%. It is important to note that for all of the technologies under consideration here, markets, and learning rates, are global. Thus cumulative world production, rather than UK application alone is the key variable for learning assessment.

When contrasted with the wide range of technology specific factors that are assessed in engineering assessment, learning curves may appear an over-simplistic method for estimating cost reduction potential. However there is an extensive literature on learning curves, a phenomenon that was first documented in 1936, and they have proved a robust tool for assessing cost reductions in a wide range of products and sectors. They also take into account all the costs of production, including staff, maintenance, rents and so on, that may not be fully included in engineering analyses. The potential for sensitivity analysis allows the impact of 'error' about the learning rate and market growth rate to be made transparent. Nevertheless learning curves have a number of limitations as a tool for estimating future costs:

- First, short run learning curves may differ from long run, particularly where the market for a technology is going through period of rapid innovation, or a transition from one technology type/means of production to another. Also, as noted above, learning curves tend to be steeper in the early stages of technology development. This suggests that some caution is needed in inferring the slope of a learning curve over relatively long time periods, particularly for relatively new technologies. The IEA report on learning curves cautions that particular care is required in extrapolating

learning curves over more than two orders of magnitude of cumulative production (IEA 2000).
- Second learning curves only predict cost reductions in terms of cumulative production. To translate this into a time trend of cost reduction requires additional assumptions about growth in installed capacity and output. Sensitivity analysis may be used to assess the impact of different learning rates and different market growth rates on future cost reductions.
- Finally, for very recent technology with limited production volumes, adequate market data will not exist. Whilst it is possible to estimate cost reductions using learning rates from closely related technologies, this is not a recommended procedure and should be regarded as less reliable.

The approach taken here is to extract the ‘best of both worlds’, where available learning curves are used to estimate future cost reductions – with sensitivities to learning rate and market growth rate made explicit. However the outputs of this assessment, and in particular the appropriateness of longer term extrapolation of current learning rates, are discussed and assessed in the light of engineering assessment.

The key policy conclusion  to be derived from analysis of learning curves is that development of technology, and hence cost reduction, depends crucially upon expanding production and deployment. This may be facilitated in the early stages by RD&D, however market creation and enablement plays a crucial role thereafter in facilitating the learning investments that provide for the innovation that drives cost reduction, bringing new, low carbon technologies to market.

## 4. Cost reduction potential by technology

### *4.1 Wind power*

Grid connected wind power, from ‘large’ turbines[6] has seen rapid market growth in the period 1991 to date. Total installed capacity worldwide increased from 2 GW to more than 20 GW now (Wind Power Monthly, 2001) and capacity factor (output per unit of capacity installed) has also improved. Market growth has averaged 22% per year in this period, accelerating to around 30% per year in the period from 1997. The historical trend in cost reduction has been similarly impressive.

*Historical trends*

The following figures illustrate growth in wind installations and price reductions in wind generation. Figures for price reduction for Denmark are used as a proxy for cost reduction, as market and policy conditions have been relatively stable in Denmark. There is some evidence that prices for the UK in  sequential NFFO rounds were bid down more rapidly than cost reductions.

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[6] current commercial turbines for grid connected power generation have installed capacities in the range 600 kW to 2.0 MW, the term ‘large’ turbine is used to distinguish such turbines from the much smaller units of a few kW up to 100kW used for offgrid and leisure applications

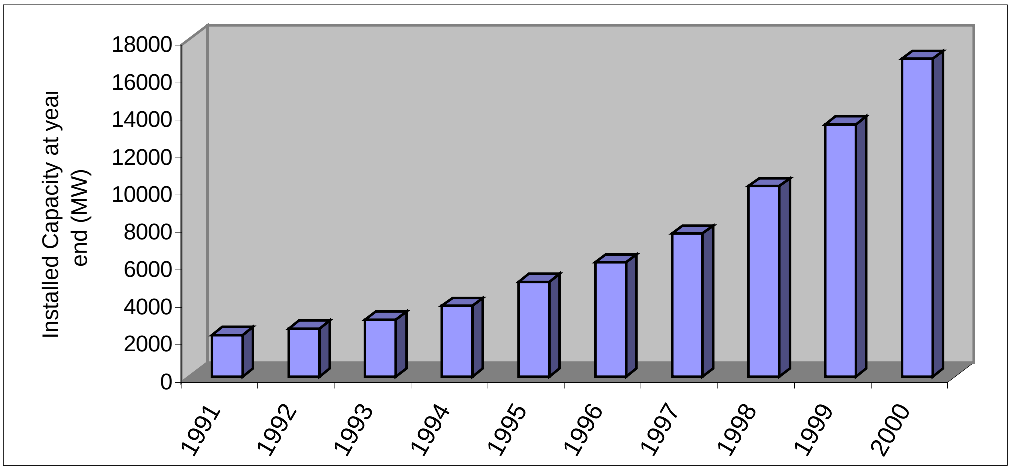

**Figure 2 Total world wind turbine installed capacity**

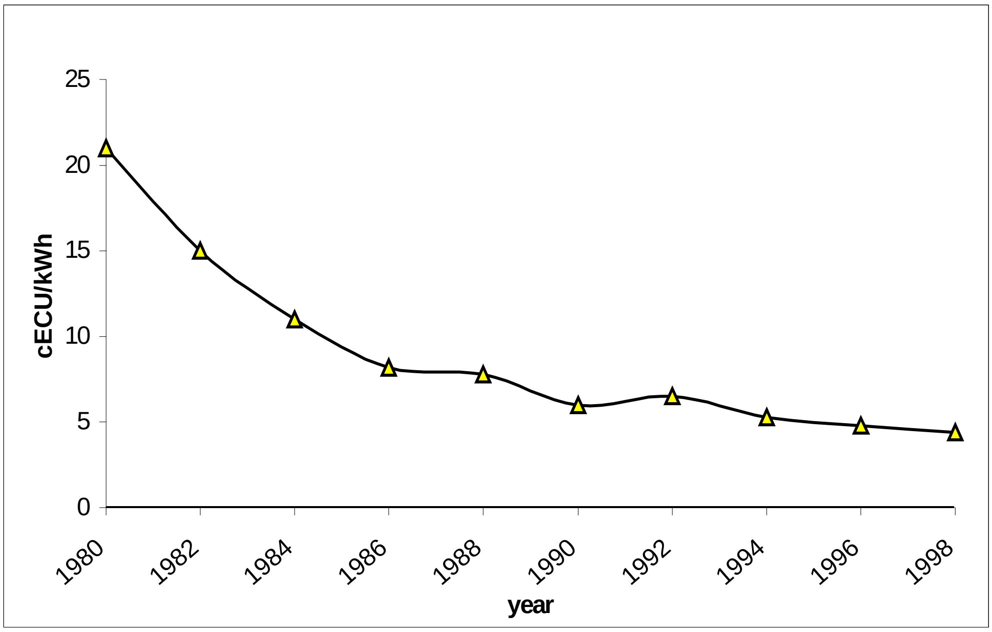

**Figure 3 Price of electricity from wind, Denmark (EU 1998, UNDP/WEC 2000)**

It cannot be stressed enough that the figures above are indicative of a trend, rather than absolute costs for all wind installations. The cost per kWh is sensitive to wind speed, discount rate and other variables and there is a wide range of costs in existing wind farms. The analysis below explores a range of costs for wind developments from ‘high’ to ‘low’ – reflecting real world variations based upon a range of factors. It is particularly important to note that cost falls rapidly with wind speed because power output from wind turbines rises with the cube of the wind speed. For this reason wind farms at the windiest sites are already close to cost competitive with the average costs of conventional power.

*Trends and Drivers*

Technological development and market growth have played a major role in reducing the capital costs of wind energy. Wind turbines have become cheaper to produce, more efficient and more reliable. As the industry has matured, learning has reduced design, planning and installation costs, and market growth has brought economies of scale. The perceived risk of investment in wind power has also decreased, leading to a lower cost of financial capital (discount rate) and longer amortisation periods. Progressively larger machines have brought significant scale economies, in terms of both the cost per unit of installed capacity ‘at the turbine’ (a 500kW machine is less than 5 times the cost of a 100kW machine) and in terms of balance of plant and electrical integration expenses (the cost of land, electrical connections, installation and maintenance, and support structures often increase little as turbine size and capacity rises). Tools for optimising turbine location have also improved. Taken together these factors have resulted in a rapid and sustained fall in the cost per unit of electrical output. Costs fell fourfold in the 1980s, and halved again in the 1990s.

### *Learning Curves for Wind*

The IEA study of Learning Curves (IEA 2000) found that the learning rate for wind energy technology in the EU in the period 1980 - 1995 was 18%[7]. The analysis suggests that although average cost of generation from the best sites is already competitive with the cost of coal fired generation, cumulative electricity production would need to rise to around 100 TWh before lowest cost becomes close to gas combined cycle generation (CCGT) - currently the cheapest generating option. This would occur around 2008 if a build rate of 25% (slightly below current trend) were sustained. Cumulative production would need to rise to more than 1000 TWh for power from higher cost sites to compete with CCGT. Figure 4 below shows the learning curves corresponding to the highest and least cost sites. It uses the learning rates and cumulative production data from the IEA study (EU learning rates and global production, see footnote 4).

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[7] EU learning rate figures are used in preference to global figures in order to remove the possible anomalies that resulted from poor siting of turbines in the 1980s in California as a result of capacity, rather than production, subsidy. Reorienting these subsidies had the effect of making US learning ‘accelerate’ simply as attention was directed to better siting (IEA 2001). But a substantial fraction of global capacity was installed in the EU in this period and the EU figures therefore provide a better proxy for world learning as we look to the future. In this section we use global capacity growth with the 18% (EU) learning rate.

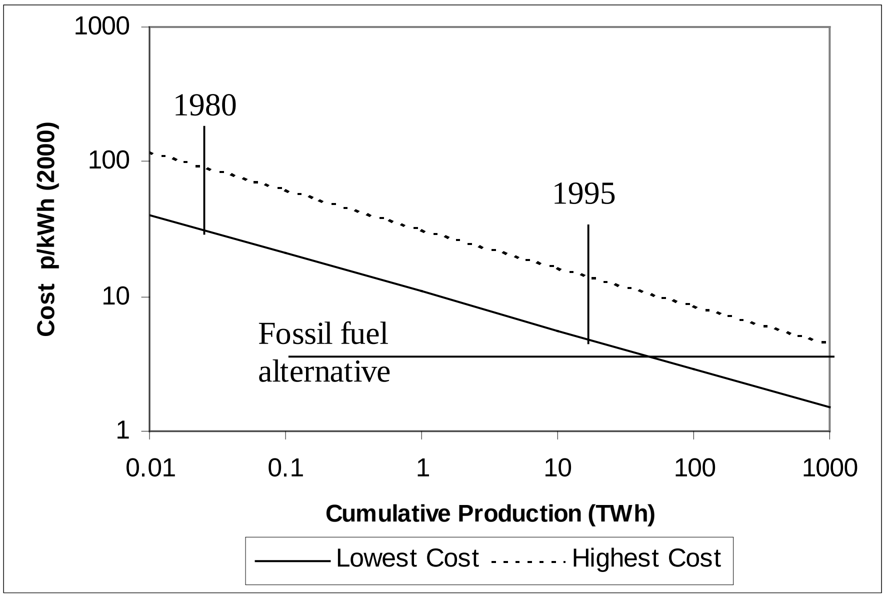

**Figure 4. Learning curves for on-shore wind derived from IEA (2000)[8].** Fossil fuel alternative is lowest cost – in many cases CCGT

Figure 5 below shows this rate of learning translated into the future assuming a certain growth in generating capacity world-wide. It is assumed that on-shore wind capacity increases at 25% p.a. up to 2010, at 15% p.a. between 2010 and 2015 and at 10% p.a. thereafter. This gives a total installed capacity of 50 GW by 2005, 145 GW by 2010, 280 GW by 2015 and over 720GW by 2025. If the actual rate of growth is slower then the rate of decline in costs will be slower. Conversely a faster rate of growth of capacity could see very low costs achieved faster. Growth to 2010 is in line with recent projections from BTM Consult, leading analysts of the wind industry (BTM Consult, 2001).

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[8] The high cost to low cost range reflects a range of factors, most notably average wind speed (typically from less than 7 to more than 10 m/s) but also other physical site characteristics and the range of financing conditions found in different EU states and under different policy regimes. Because this analysis is based upon empirical evidence of cost trends in kWh terms it is difficult to disaggregate these factors and undertake sensitivity analysis of, for example, wind speed and financing conditions. Instead the analysis uses 'real' cost variations to ensure a reasonable spread of both wind speeds and financing conditions. It is notable that, during the 1990s, the interest rates wind developers were able to secure varied between 6% (Germany) and 12% (UK), reflecting perceived risks and the level of policy security, but wind speed variations were able to more than offset these differences (Wind Power Monthly September 2000).

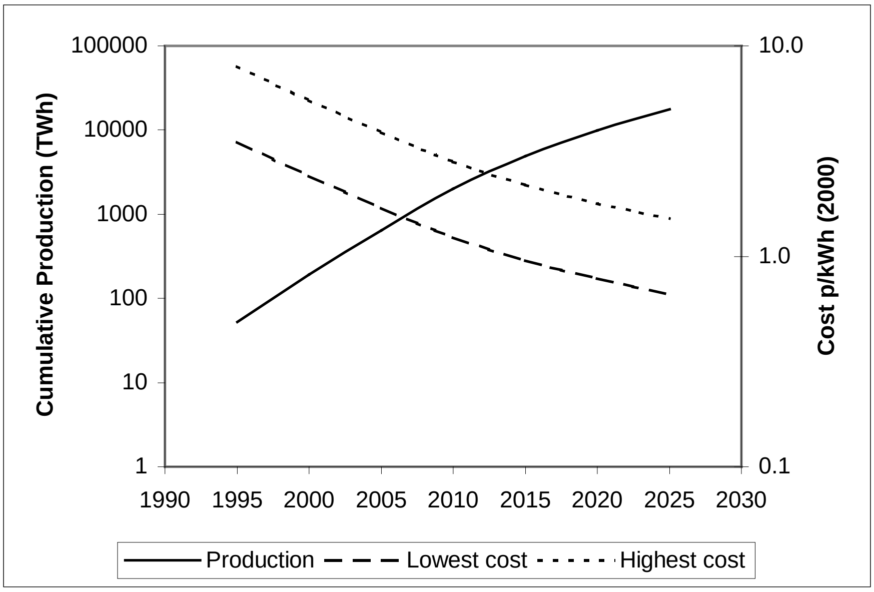

**Figure 5. Projections of wind energy costs based on continued learning and growth in global capacity.**

The implications of this projection are startling – wind falls to less than 1p/kWh for good sites onshore. The sustainability of this global build rate is difficult to predict, however the progressively declining build rate described and modelled above is ensures that even by 2025 installed capacity is well below current estimates of global practicable potential. The key issue is therefore whether, and for how long, we can extrapolate the historic learning rate.

There is some debate over the extent to which reduction in the cost of wind energy is set to continue. Some studies (UNDP/WEC 2000) indicate cost reductions ‘bottoming out’ in the period around 2015 at around 3 US cents/kWh (2.0 p/kWh). Even given the relatively high rates of continued market growth described above, wind would occupy only a small share of world electricity supply by this date, and technical potentials would be far from exhausted. There is, therefore, no reason to presume that this bottoming out is a result of market saturation (such that reduced market growth leads to reduced cost reductions). It could, however, arise from a reduction in the learning rate.

Is this likely? According to some assessments wind energy capital costs are expected to decrease by 50 – 75% in the next 20 years (EU 1998). This is probably lower than the historical trend, and historical output cost reductions were also driven by better siting. Despite opportunities for re-powering older sites with fewer, larger, better located turbines, this would appear unlikely to be entirely repeatable. In addition, costs also fell due to scale economies as turbine sizes increased - the average capacity of individual wind turbines has increased almost tenfold since the late 1980s - this also appears unlikely to be repeatable, at least for onshore designs. However, machine sizes will continue to increase, if more slowly, improvements in design, materials and manufacturing continue to drive cost reduction, and market expansion continues to yield economies of scale in manufacture. One recent study also identifies significant potential for ongoing innovations such as multi-rotor design, and in power electronics (De Vries 2001).

Overall the engineering evidence for reduced learning is not clear cut. Despite this, it does seem reasonable to consider the possibility that the learning rate for wind power may be lower in future. Whilst it is not possible to be precise about the extent to which this will happen the projection shown in Figure 6 (below) assumes a lower learning rate (10%) once installed capacity exceeds 100GW (around 2008)[9]. This results in a cost range of 1.0 – 2.4 p/kWh in 2020.

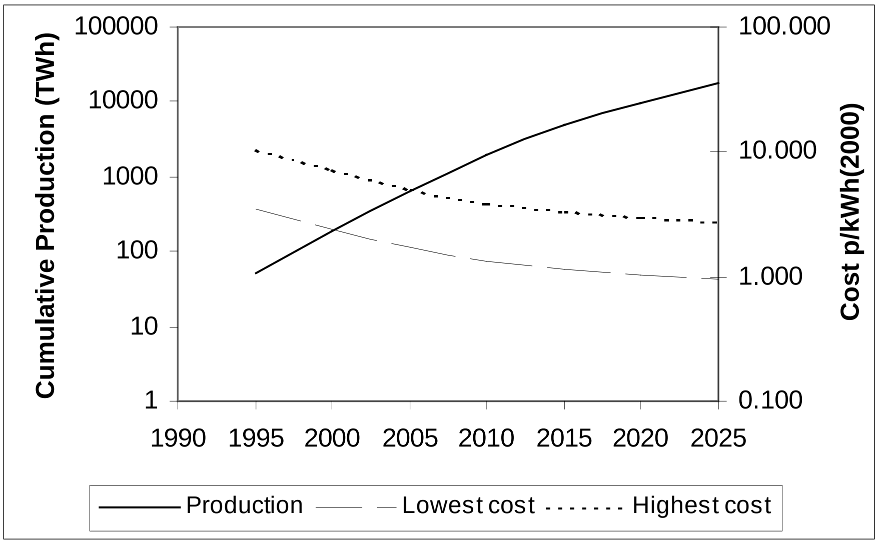

**Figure 6. Projections of wind energy costs based on growth in global capacity with reduced learning as technology matures.**

The high and low cost ranges illustrated in figures 5 and 6 aggregate a range of factors including financing conditions (discount rates), wind regimes and physical remoteness. Overall, in order to accommodate these varied uncertainties, and to take into account the potential limitations on the lower estimates suggested by engineering assessments (which suggest costs falling to around 2.0p/kWh UNDP/WEC 2000) a range of 1.5 – 2.5 p/kWh seems reasonable.

*Conclusions*

Wind is a well-established technology, and learning rates can be used to project future cost reductions with some confidence. Given reasonably conservative market growth (lower than historical trends, and falling progressively) projections, and assuming that the learning rate also declines over time (as suggested by some engineering assessment) the analysis suggests the following conclusions:

- **Low cost wind sites are able to offer an average cost of electricity that is lower than current CCGT costs by around 2008.**
- **Learning curve extrapolations suggest that low cost wind sites are able to deliver electricity at an average cost as low as 1 p/kWh by 2020. However some caution is required in interpreting this figure as engineering assessments tend to be less optimistic, hence;**
- **A cost range of 1.5p – 2.5p/kWh is reasonable for 2020**

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[9] There is some evidence for such declines in the literature. For example Grubler et al (1999) show such a reduction in learning rate occurring for gas turbines.

In the UK a key issue is the limitations placed upon the development of onshore wind by planning constraints and public acceptability. Whilst this is unlikely to significantly affect global installation, and hence progress down the learning curve, (unless similar concerns in other countries affect global rates of deployment) this issue has serious implications for the contribution onshore wind can make in the UK energy system of the future. It is a key driver of interest in offshore applications, to which we now turn.

### *4.2 Offshore Wind*

There is little debate that offshore wind offers a large potential resource. As discussed above the DTI figure for accessible potential is conservative in comparison with other studies, makes considerable provision for competing uses of the marine environment, and further reduces technical potential to exclude much of the potential in deeper waters. Despite these constraints, accessible potential amounts to around 100 TWh/year – nearly 1/3 of UK electricity demand.

Costs for offshore wind are currently around double those for onshore development on a good site and similar to those applying to low wind-speed sites onshore. Wind speeds offshore are similar to those for good onshore sites. The higher off-shore costs reflect additional transmission costs, installation costs offshore, and additional operation and maintenance costs. They are based upon limited experience, in nearshore waters, mostly gained by developments close to the Danish coast. However, development planned for Horns Rev, in the Danish North Sea will take wind energy into one of the most hostile marine environments in the world. Success of projects such as this are considered to be ‘decisive’ for subsequent projects (BTM Consult 2001) Two notable features stand out with regard to the costs of developing offshore wind and likely trends in future costs:

- Firstly, the physical/engineering *basis of* the additional costs referred to above are likely to rise as development is expanded and moves further offshore. The ‘easiest’ and closest sites will be developed first, and it is possible that perceived visual intrusion will drive turbines further offshore as a larger proportion of the resource is exploited, pushing development into deeper waters and increasing the engineering challenges.
- However, secondly, current costs are based upon very limited experience, using turbines essentially developed for onshore utilisation. There are two key areas for technology development and learning: (a) in the development of turbine technologies explicitly designed for the offshore environment. (b). in offshore engineering of wind farm installation.

The key question in projecting the potential for cost reduction in offshore wind is thus the extent to which learning and technology development can offset rising engineering challenges, and how rapidly. As for all technologies, this will depend upon both installation rates, and the learning rate.

### *Market Growth*

Offshore wind is widely predicted to grow rapidly over the next decade. Considerable development is planned in several countries, most notably Denmark, the UK, Germany and the Netherlands. Around 3000 MW is planned for around 2005 (wind Power Monthly 2001) and some plans in different countries are shown in table2.

Though how much of this will be delivered remains to be seen. Projections differ, and it is too early to calculate a meaningful growth rate, however leading analysts project that around 2000 MW of offshore wind will be installed by 2005 (BTM Consult, 2001).

| **Country** | **Built** | **Planned/ Proposed** |
|---|---|---|
| UK | 4 MW (Blyth) | 1000 – 1500 MW by 2010 (Crown Estates sites) |
| Denmark | 52 MW | 750 MW by 2008 (utility obligations, 4 sites) govt long-term aim 4GW |
| Germany |  | Up to 10GW, timescale unclear, initial plans (sites with permits) 3GW |
| Sweden | 22 MW | 175 MW under development, long-term potential ~ 3GW |
| Netherlands | 19 MW | 1500 MW by 2020, 240MW well advanced |
| Ireland |  | 500 MW + (plans for farms at Dublin Bay and Arklow Banks) long term aim unclear |

**Table 2 Offshore wind progress and plans**

*Learning curves and historical experience*

Despite growing interest in offshore wind, and the development of a number of relatively large-scale offshore farms, most notably by Denmark, offshore wind is still in its infancy. It is reasonable to expect that offshore wind will exhibit the learning rate of 15 – 20% that is typical of energy technologies, but it is too early to actually calculate meaningful learning curves.

Learning for offshore wind has two components that differentiate it from onshore: (a). dedicated design of offshore turbines; (b). offshore engineering. We therefore need to consider what can be inferred from onshore wind development – and what cannot – and to assess the extent to which offshore wind may draw upon existing practise in marine engineering in other areas:

- There is clearly ‘spillover’ between learning investments in onshore technologies, and in development offshore, indeed the development of onshore technologies over the last twenty years has in many respects ‘paved the way’ for the move offshore, particularly by increasing turbine technology to ‘megawatt scale’. However the move offshore offers opportunity for additional technological development – for example, turbines may be larger and need not be designed to minimise noise, tip speeds may thus rise, raising conversion efficiency. The offshore environment also raises new challenges for reliability and robustness of design – it is reasonable to expect considerable improvements in this area as experience progresses. The contention that follows from this is that turbine designs for offshore wind will continue to exhibit learning rates at least as high as the historical average for onshore.

- Which are the most relevant marine technologies and what can they tell us about learning rates for offshore wind? At first glance offshore wind engineering would appear closely related to other offshore industries. It is, but the devil is in the detail, and as a result the potential for innovation and learning remains high and the direct application of learning rates from other industries difficult to justify:

- The first point to note is that there is relatively limited read-across between oil and gas engineering and wind (personal communication with oil industry experts). Wind turbines are installed in relatively shallow water, but are necessarily tall, freestanding, and must withstand very high lateral loadings. By contrast oil and gas rigs are tethered deep water floating structures with a very different set of engineering challenges (mostly surrounding drilling and extraction).
- For the most part, offshore wind farms utilise monopile foundation structures. This involves the application of already mature (widely deployed) techniques, but applying them to wind power raises new challenges – the combined loadings on the tower and foundations from the interaction of turbine motion and waves for example.
- Undersea cabling for power transmission and control is a well-established technology. However operation and maintenance of offshore farms, and remote control of offshore devices is a new area of activity.
- The specifics of installing wind turbines offshore, in particular, in the construction and manoeuvre of very tall, free standing fixed structures has already required much innovation – specialised construction facilities in docks, deepwater cranes, etc.

All this suggests that continued learning and considerable cost reductions should be expected as developments offshore take place on a significant scale. How to best to characterise and quantify this is less clear.

One view of off-shore developments is that they are essential to maintain the growth in wind capacity once all the favourable on-shore sites are developed and if there is increased resistance to turbines on-shore. The off-shore sites offer higher wind speeds and better availability than most land sites, but incur the additional costs discussed above. In this view the off-shore development can be regarded as an adjustment to the overall wind-energy learning curve.

If the view that offshore is essentially an extension of onshore technology and cumulative production, with much the same learning rate, proves correct then the effect is to move the learning curve out relative to the best sites onshore – the curve for offshore becomes close to that for lower wind sites onshore. This is illustrated in figure 7 Here the same learning rate is assumed for both technologies and the transition from low-cost on-shore sites to off-shore involves a one-off cost. This corresponds to a shift from the best on-shore cost of about 2.4p/kWh to an estimated 5.5 p/kWh for off-shore[10].

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[10] This figure is taken from DTI 1998. It is notable that figures from recent and planned developments in Denmark suggest a somewhat lower figure (Danish Energy Ministry 1999) and hence that this figure may prove conservative.

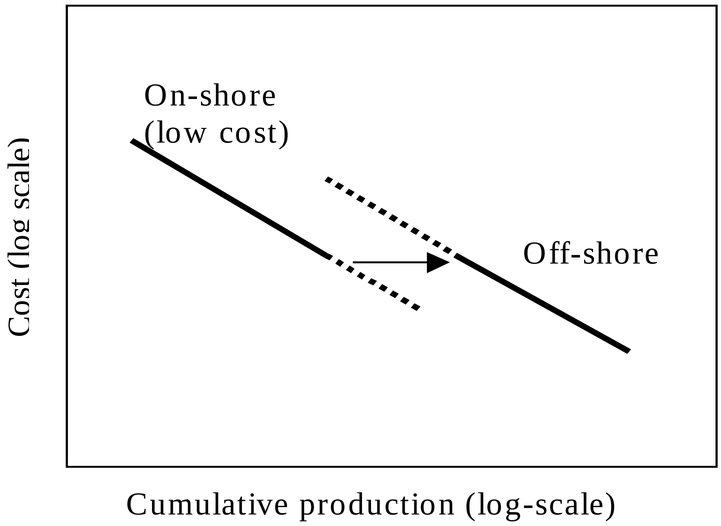

**Figure 7. Representing on and off-shore wind development as part of the same learning curve.**

It is impossible to model cost reduction in developments offshore as effectively as development onshore until market growth rates, learning and the linkages between developments on and off shore become clearer. Nevertheless if this view proves correct then the curve for less favourable sites in figure 6 could provide an indication of progress with offshore wind.

An alternative view is that off-shore wind, though an extension of on-shore development, effectively alters the learning curve as a result of the different engineering challenges and opportunities offshore. Whilst it does not seem likely that offshore wind will exhibit a higher learning rate than the historical rate for onshore wind, the potential slowdown in learning modelled in figure 6 could happen later. In this case the curve for higher cost sites shown in figure 5 could provide an indication of progress offshore.

Provided on and offshore wind technologies continue to co-develop, and offshore wind is part of the continued market growth modelled in these figures, the cost reduction curves for higher cost sites onshore provided in figures 5 and 6 could thus provide some indication of the range of possibilities for developments offshore. The range of costs in 2020 that this would suggest is 1.8 – 2.4p/kWh.

However, many of offshore wind developments are not predicted to come into operation until the period 2002 – 2005. If these developments generate electricity at costs of around 5.0 – 5.5 p/kWh, as projected, then they will be about five years ‘behind’ the cost reductions expected for the more expensive onshore sites. This may be characterised as delayed progress along the curves for the higher cost sites shown in figures 5 and 6. This is illustrated in figure 8 and would suggest that offshore wind could generate electricity at a cost of 2.2 – 2.6 p/kWh.

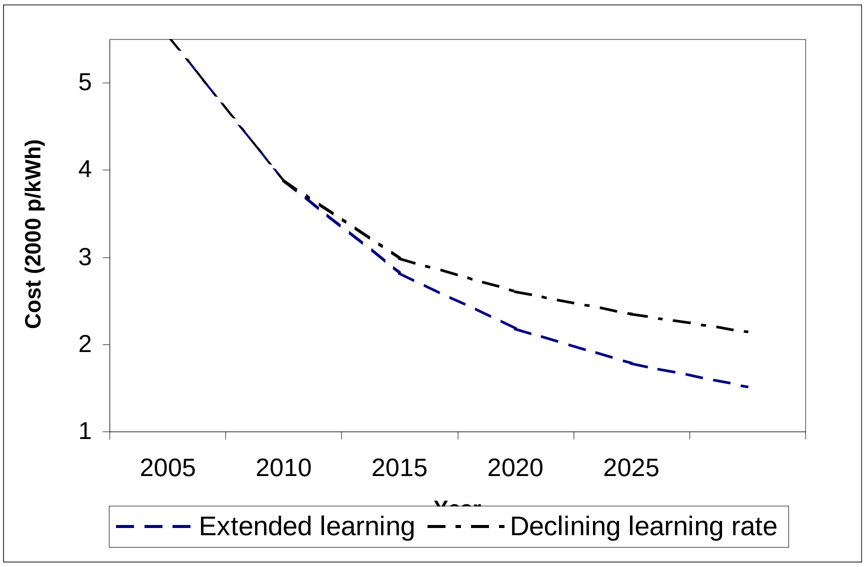

**Figure 8 – cost reductions in higher costs onshore as to illustrate progress in offshore wind**

The uncertainties that surround these figures are substantial. Given the projected rapid growth of off shore capacity, another possible effect could be to defer the slow-down in build rates modelled in figures 5 and 6, this would ensure that the higher initial (pre 2010) rate of cost reduction over time shown in these figures could be sustained beyond 2010, which means that **cost reductions for all wind applications will happen sooner**.

Alternatively, if offshore development proves to have very limited relation to developments onshore, an entirely separate learning curve would need to be constructed and production growth rates for onshore and offshore would need to be considered separately. Modelling this is not yet possible, but the result would be that even with identical learning rates, if growth in offshore *production* proceeds at a higher rate (relative to existing *offshore* capacity) than on-shore, then **offshore could 'catch-up' with onshore costs**[11]. It is not possible to quantify or to test these possibilities empirically at this point in time. And of course if offshore wind developments do not proceed as projected or if offshore wind proves to have less potential for learning, then costs will be higher.

Overall, given both the engineering considerations and the proxy learning curves discussed above a cost range of 2.0 – 3.0 p/kWh by 2020 seems reasonable. The upper end of this range is conservative in comparison to the historical developments in wind energy onshore and in the light of the engineering evidence discussed above.

*Conclusions*

Engineering assessment and proxy learning curves (high cost sites onshore) suggest that **the cost of offshore wind in 2020 is likely to be in the range 2.0 – 3.0 p/kWh.**

The upper end of this range is conservative. It is important to note that:

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[11] This view may also be placed in simple engineering terms; cost reductions specific to offshore installation techniques, and the technical advantages that may be enjoyed by offshore turbines, combine to offset the lower capital cost advantage of locating turbines onshore.

If offshore wind is an extension of offshore wind development, with a similar, but separate learning curve – given a high rate of growth of offshore development;

- **Offshore wind costs will tend to converge with those for onshore wind.**

In addition;

- **Developments offshore could extend learning and market growth for on and offshore wind, accelerating cost reductions in all wind applications.**

*4.3 Photovoltaics (PV)*

Like wind energy, markets for PV have seen rapid growth, and costs have fallen dramatically. However PV remains far from cost competitive with most alternatives (the exception being so called niche markets for locations remote from conventional electricity grids and specialist applications such as small consumer products and satellites).

*Historical trends*

Market growth in PV shipments has averages 15% since the mid 1980s. In the last five years installed capacity has grown at around 30% per year (UNDP/WEC 2000). Capital costs (of modules) have fallen from several hundred pounds per peak Watt (Wp) in the early seventies, to around four pounds today (Anderson 1998). Cumulative installed capacity is of the order of 600 to 800 MW. In addition, the conversion efficiency of the best commercially available modules has risen steadily, from under 10% in 1980, to around 14% today.

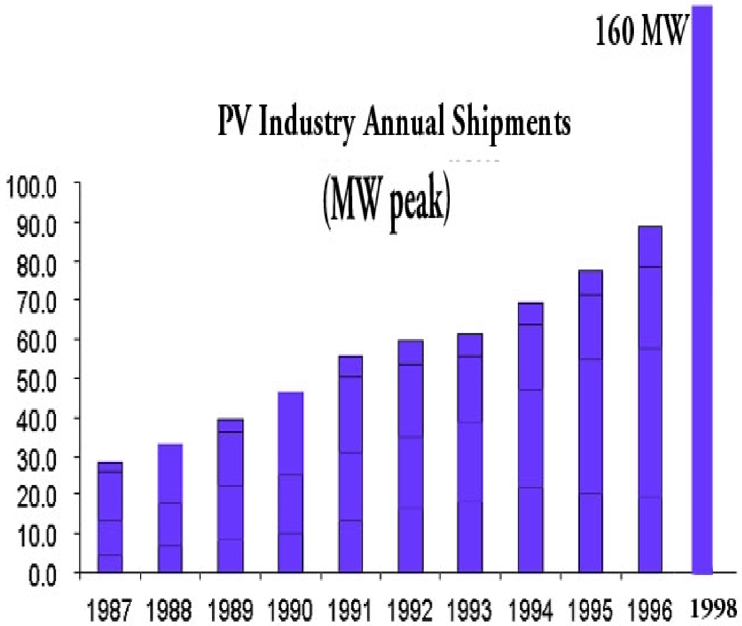

**Figure 9 World PV module shipments 1987 to 1998**

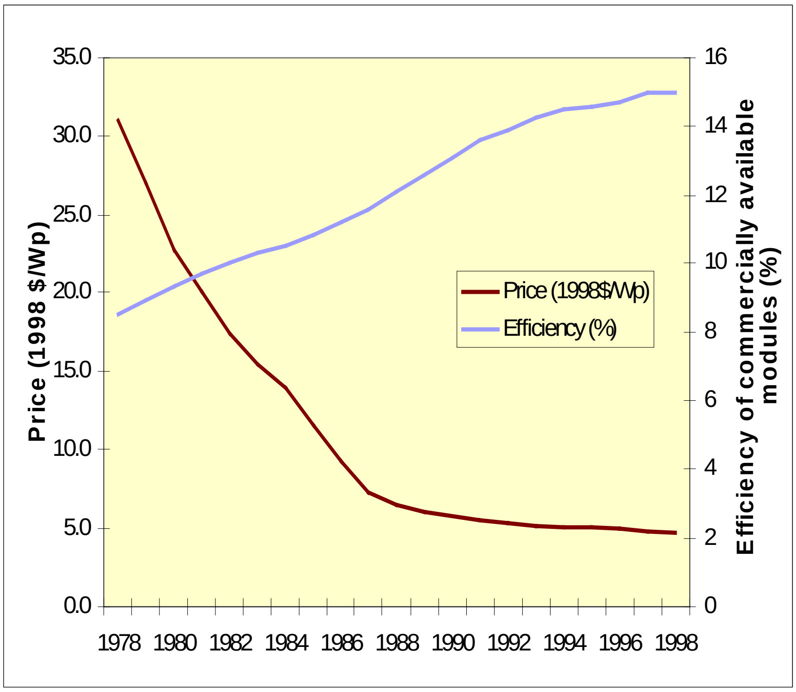

**Figure 10. Price and conversion efficiencies for PV modules**
(source IT Power Ltd)

*Learning Curves*

Learning curves for PV have also been explored in some depth in the literature. A number of studies (IEA 2000, PCAST 1997, cited in Anderson 1998) suggest that a learning rate of the order of 18 to 20% has been observed for installed PV.

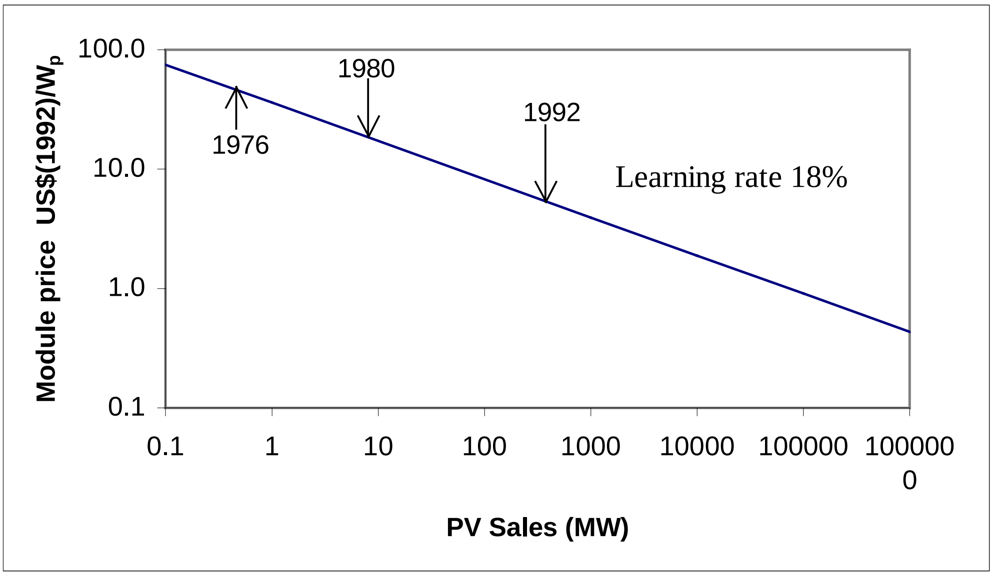

**Figure 11. Learning curve for PV modules on the world market (Source. IEA 2000)**

The issues for PV are rather different to those for wind. The market for PV, in terms of annual shipments/installation is around 1/10th of that for wind, and costs per kWh more than ten times as high. There is less risk of siting constraints restricting growth in PV application as there is little shortage of available building surfaces. Some countries, notably Japan, Germany, the US, but also Denmark, Italy and the Netherlands, are pursuing rapid market expansion through generous support schemes.

Engineering assessments, far from projecting a slow down in the learning rate actually suggest that PV may be about to experience accelerating cost reduction as a result of innovation (the commercialisation of reliable thin film technologies). A direct comparison between engineering assessments and learning curves (UNDP/WEC 2000) found that the historical learning curve for PV provides less ambitious cost reduction projection than recent engineering assessments. If PV may soon go through a technological transition to inherently cheaper thin film technologies will this fundamentally change the learning rate, or will the change be characterised by a short-term shift that leaves the longer term, underlying rate unchanged? Learning rates of up to 30% are not untypical in the semi-conductor industries. The 18% historical learning rate of the last 15 years may prove conservative[12].

These considerations suggest that projecting costs on the basis of historic learning rate and market growth rate may understate the potential of PV. There is also some prospect that PV will go through a further wave of innovation, perhaps in around 20 years time, as so called 3rd generation technologies – semi-conducting polymers and dye sensitised glass cells – currently at the basic research stage come to market. A key issue for PV is therefore to deal with continued innovation in the much longer term, beyond the time horizon over which it is possible to be at all confident about learning curve projections. Nevertheless, assuming that the same rate of learning can be extended into the future, and that PV installations grow at an average 25%p.a. then there will be significant cost reductions over the period to 2025. This is illustrated in Figure 10 below, which also shows the assumed growth in installed capacity.

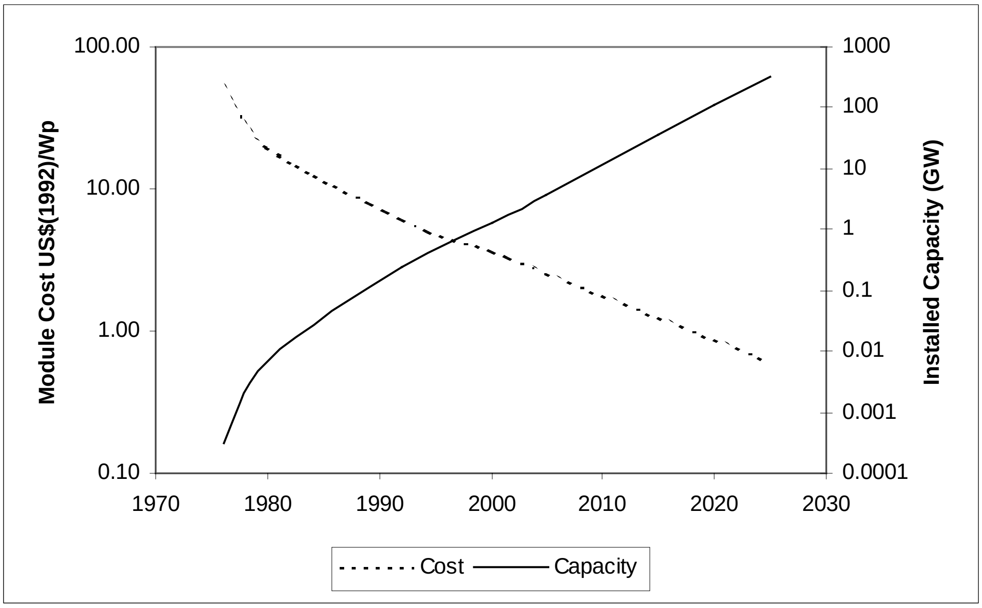

**Figure 12. Illustrating the growth in capacity and reduction in costs for solar PV assuming a learning rate of 20%**

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[12] In a recent review of learning rates McDonald and Schrattenholzer present evidence that the rate for PV modules is 20% rather than the 18% reported by the IEA.

It is important to note that the learning curves above are for installed capacity and reflect capital costs. Costs per unit of output (kWh) are likely to follow a slightly different trajectory due to improved conversion efficiencies, efficiencies in balance of system components for grid integration, reduced installation costs and improved siting, as well as cost reductions in balance of system equipment. However, allowing for a modest increase in efficiency and neglecting other additional learning, with a 20 year lifetime and at an 8% discount rate, the projections suggest that PV could deliver electricity at around **10p/kWh by 2020, falling to 7p/kWh by 2025**. With a 15% discount rate these figures increase to **16p/kWh and 10p/kWh**.

As BIPV electrical output is available to the building upon which the PV installation is situated, many analyses consider cost competitiveness in terms of retail price electricity – currently around 7p/kWh. Our analysis thus suggests that PV will only begin to become competitive after 2020. It is notable that in **sunnier latitudes** (2000 kWh/kWp/yr) the costs at **2020 and 2025 become 4p/kWh and 2p/kWh** respectively – close to average costs for current grid conventional generation technologies.

*Offset costs*

The potential for BIPV panels to form part of the skin, or roof, of buildings can have a dramatic effect on the economics of BIPV because it is possible for PV to replace conventional cladding materials. In this instance only the incremental costs of PV – over and above the costs of alternative cladding or tiling – should be factored into the cost equation. PV roof tiles are already commercially available. In some instances, if BIPV is incorporated in a new-build or major building refurbishment and where relatively expensive materials are displaced, BIPV is already close to being commercially viable (ie able to deliver electricity at less than the cost of grid electricity to the end user) (ETSU 1998). For ease of comparison with other technologies, and because such cost offsets vary and are application specific, we are neglecting offset costs in projections for PV. However it **may prove highly significant to growth in the use of BIPV, particularly in the commercial sector where there is significant potential for expensive cladding to be replaced with PV.**

*Conclusions*

Projections based upon historic trends for market growth and learning rate suggest that in the UK;

- **In the UK, PV will not become competitive with end user electricity tariffs until between 2020 and 2025. Depending on a range of assumptions about balance of systems costs and efficiency and discount rates a cost range of 10 – 16 p/kWh for 2020 appears reasonable.**

- **This neglects the potential for offset costs for building cladding, which may be significant and in appropriate buildings has the potential to dramatically improve the economics of BIPV.**

There is some evidence to suggest that both;

- **Learning rates and market growth rates could be higher than projected.**

And because of considerable potential for sustained cost reduction beyond 2020;

- **Costs could fall to a range of 6 – 10p/kWh by 2025. Sustained development with a view to the long term is of particular importance for PV.**

Finally because the UK has relatively poor solar insolation;

- **Costs in many regions of the world are likely to be much lower – around 4 p/kWh by 2020.**

### *4.4 Wave and tidal stream energy*

By comparison to wind and PV, wave energy and tidal stream are very much in their infancy. Currently around 1 MW of wave energy devices is installed worldwide, and almost all of this capacity is prototype projects. There is currently no tidal stream capacity operating, though prototypes are planned for the near future (DTI 2002). Because of the relative lack of data on tidal stream the remainder of this discussion focuses on wave energy. This is not to make any judgement of the relative merits of the two options.

RD&D into wave technology world-wide is encouraging, projected costs of leading designs have fallen considerably in recent years and installed capacity is widely predicted to grow exponentially over the next few years, rising to around 6 MW. The potential resource in the UK is very large – technical potential is least 2 ½ times total UK electricity consumption. Because waves are created through the action of the wind across large areas of ocean, and because waves, once created, continue to transmit energy for some time and distance, sea state (waves) is inherently more predictable than wind. This means that though intermittent, electrical output from wave energy is more predictable than wind.

The relatively undeveloped status of wave energy presents problems for this analysis. Because market experience is so limited data for learning curves is not available. Moreover, there are a large number of prototype devices, and a wide variation between approaches, and this militates against the use of ‘proxy’ technologies for learning curve assessment. However, detailed work on the costs and engineering feasibility of leading UK prototypes has been undertaken for the DTI (Thorpe 1999). These assessments of wave energy use a parametric model, based upon engineering costs, to assess likely costs of devices that are, for the most part, at the research stage.

#### *Leading designs*

The first patent for a wave energy device was filed in Paris in 1799 by the Girards, and by 1973 there were already 340 British patents for wave energy devices. The number continues to rise (Shaw, 1982).

To date, attempts to design and deploy cost-effective devices have met with limited success, the main commercial success being the use of wave energy to power navigation buoys. However, the last five years have seen considerable progress in wave energy development in many countries. Several companies are developing and deploying new devices that represent a significant improvement over older concepts.

A very large number of designs for wave energy devices have been proposed. A much smaller number appear promising at present, and the ‘best’ device is yet to be identified. Devices can be classified as shoreline (sometimes referred to as first generation as they are closest to commercial deployment (Duckers 1998)), nearshore (along with some deep water, float based devices these are often referred to as second generation) and offshore (many of which are considered third generation, longer term options). Devices may be further classified by generic technology type, though there is some overlap. The classifications include:

- pneumatic devices, such as the oscillating water column (OWC), which use wave motion to compress and decompress air, from which energy is extracted
- float based devices which utilise a buoyant float moving with the waves, reacting against a reference point such as a sea bed anchor in order to harness energy
- spillover devices which utilise wave height to replenish a reservoir of sea water which then runs a turbine
- raft type devices which use the relative motion of adjacent rafts or pontoons to harness wave energy
- moving body devices which articulate in the water in some way, inducing motion which may be used to drive a hydraulic motor in order to extract wave energy

Currently, devices receiving serious development or demonstration include:

- Shoreline OWCs in Australia, China, India, Japan, Norway, UK
- Commercial scale shoreline OWC, *the Limpet*, in Scotland
- *Tapchan* spillover device
- *Pendulator* pendulum-flap/spillover device
- *Osprey* nearshore, bottom mounted OWC
- *Mighty Whale* floating OWC
- *Sperbouy* multi-chambered OWC
- *Sea Clam* pneumatic bag-type device
- *Danish Wave Power* float based device
- *Ocean Power Technology* float based device
- *Hosepump* float based device
- *Archimedes Wave Swing* float based device
- *IPS Buoy* float based device
- *Twin Membrane Wave Converter* float based device
- *Wave Dragon* and *Floating Wave Vessel* spillover devices
- *Wave Plane* spillover device
- *McCabe Wave Pump* raft-type device
- *Pelamis* raft-type device
- *Edinburgh Duck* moving body device
- *PS Frog* moving body device
- *Bristol Cylinder* rotating float based/moving body device

Of these the shoreline and near shore OWCs are for the most part closest to commercial deployment, though float based devices are already in use for niche applications such as navigation buoys, and some spillover devices also appear highly promising in the medium term. The other devices are still at the R&D stage, though some are much closer to commercial deployment than others. Several hold considerable promise for the longer term.

*DTI cost estimates*

Commercial scale wave energy is yet to become a reality and as such empirical evidence on costs does not exist. Only once commercial-scale developments and demonstrations are realised will such evidence become available. Nevertheless wave energy devices under development in the UK have been subject to rigorous and independent assessments of probable capital and generation costs should commercial scale development be realised (Thorpe 1999). It has not been possible to secure data on devices under development in other countries, however there is no reason to presume that costs and trends differ substantially.

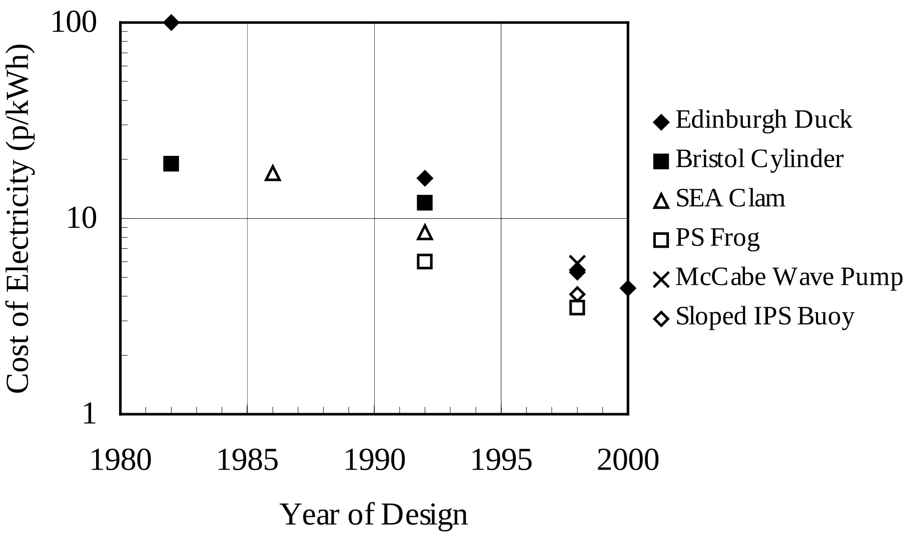

**Figure 13: Evolution of Predicted Electricity Costs for Offshore Devices (Thorpe 1999)***

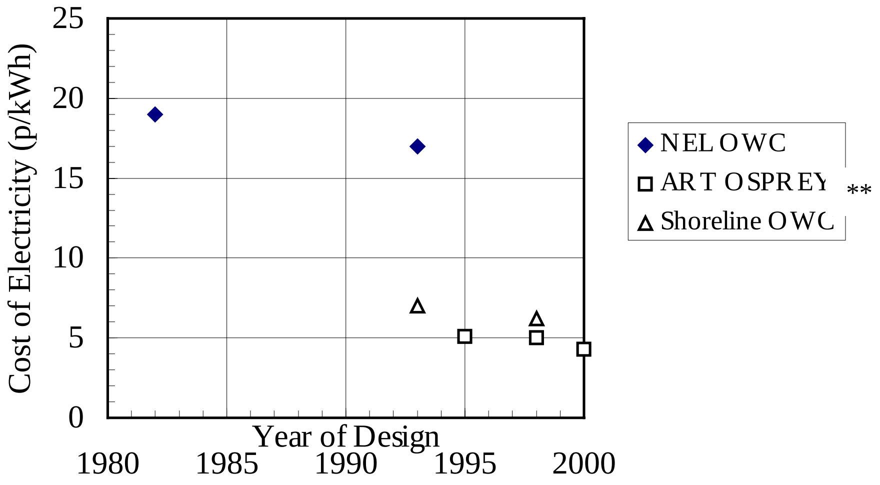

**Figure 14 Evolution of predicted costs for OWC Devices (Thorpe 1999)***

* Based upon 8% discount rate

** ART are now Wavegen, developers of both the Osprey and the Limpet

Clearly there are uncertainties associated with these estimates. In the absence of operational experience and data for almost all technologies a degree of uncertainty cannot be avoided. Nevertheless, the extent of uncertainty in most of the variables on which these assessments are based can be assessed; for example high to low capital cost estimates (based on design specs). The costs presented above are the mid-range estimates, the inter-quartile range is typically around 20% of these median values (Thorpe 1999). The offshore nature of wave energy adds considerably to capital and maintenance costs and significant reductions in projections of this component of total cost were important in driving the cost reductions indicated in the figures above.

It is important to note that although all devices assessed in the UK have demonstrated significant downward trends in cost, some devices are much closer to commercial development than others because of the scale of installation that would be required to deliver the cost levels indicated in the DTI study.

For the most part, near-shore and shoreline devices are closest to commercial competitiveness, with costs in the region of 4.5 – 6 p/kWh. As a result several devices are economically viable with support from pre-commercial demonstration through renewables support schemes such as the Scottish Renewables Order – though often some supplementary non-commercial investment has also been required. The Limpet is in operation with support from a contract under SRO 3, and the OSPREY and Pelamis have secured support from Irish and Scottish renewables support schemes. But most devices will require considerable further development before reaching this stage. As the number and variety of pre-commercial demonstration schemes increases, confidence in cost estimates will improve. The Government has recently signalled an increased willingness to support wave and tidal schemes through the pre-commercial demonstration phase (DTI 2002, PIU 2001).

Overall, there is considerable uncertainty surrounding the economics of wave energy, reflecting the relatively immature status of the technology and market. Nevertheless, there is clear evidence that the (theoretical) economics are steadily improving as RD&D progresses, and significant cost reductions have been achieved over the last 5 – 8 years. Wave is now leaving the laboratory and entering a large scale demonstration phase.

*Assessment of cost reduction potential*

Because market experience is so limited it is not appropriate to apply a learning curve to wave technologies. Although the learning curve for wave technologies is likely to lie in the 15 – 20% range typical of energy technologies, attempts to model cost reductions using a proxy learning curve indicated that uncertainties about market growth rates, and appropriate cost ‘starting point’, result in uncertainties so large as to render projections meaningless. However, based upon the DTI estimates, costs of around 4.5 to 6p/kWh seem reasonable for the short term (perhaps 3 – 4 years, see below), for those devices that are already entering pre-commercial demonstration. It is reasonable to expect that these early devices should begin to progress along a learning curve typical of energy technologies. The rate at which costs fall will therefore depend upon willingness on the part of policymakers to support wave technology through this highly uncertain initial phase. With much of the industry, existing plant, and planned demonstrations located in the UK, UK market support will have an important impact on cost reductions in wave energy.

Learning rates provide one key measure by which continued policy support might be assessed (and costed – learning investments are the area under the learning curve on a log-log plot, see appendix 1). Market growth of 25% pa would be associated with quite small absolute levels of installation at this early stage, but would deliver a doubling of cumulative production in around 3 – 4 years, and it would be reasonable to expect cost reductions of at least 15% over such a timeframe. Early devices should therefore be delivering energy at a cost of around 3.8 to 5.1p/kWh by this stage, based upon the DTI estimates. However the DTI figures are projections and assume some experience has already been gained. Allowing for early learning over the next 3 – 4 years, and a doubling of cumulative production in the 3 - 4 years thereafter, it is reasonable to expect costs of the order of **4 – 5p/kWh by 2008 – 2010**.

However it is important to note that wave energy is typical of new product markets in the very early stages of development. With such a wide variety of approaches, and many small firms/research institutions involved, it is by no means clear which device type will become dominant (see Utterback 1997 for a discussion of the evolution of new product markets). We have already noted that some of the technologies under development are currently further from commercial development, but offer much larger technical potential. More expensive options will need support too, and some will fall by the wayside. It is important to note that the DTI assessment of the Duck, for example, is based upon a 2GW installation; it would not be possible to get this stage without support for much smaller and more expensive early prototypes. A longer term view – perhaps growing markets with a view to 2020 – is appropriate for such technologies.

*Conclusions*

Attempts to apply a learning rate to wave technologies demonstrated that such an approach is not appropriate for a technology in such an early state of development. Cost estimates using a parametric model of engineering costs suggest that costs of around 4.5 - 6p/kWh may be achieved for a number of UK designs. However, the level of development required to get to such a cost differs considerably between designs. Nevertheless, for leading designs, primarily nearshore devices;

- **Costs of 4.5 to 6p/kWh are likely in the short term (3 – 4 years) for early commercial devices.**

Modest market growth (25% pa), with a learning rate of 15% would be expected to deliver cost reductions of around 15% in the subsequent 3 to 4 years. Hence:

- **Policy support sufficient to deliver market growth of 25% per annum in the period to 2008 – 2010 should deliver cost reductions equivalent to costs of around 4 to 5p/kWh within this timeframe for early commercial designs.**
- **This provides a ‘target cost’ by which success in wave developments may be judged, and continued policy support assessed.**

Nevertheless, wide heterogeneity of designs is typical of innovative new products, and given the expectation that some designs offer larger technical potential, but are much further from commercial exploitation;

- **Longer term devices also need continued support, perhaps geared towards an expectation of early commercial deployment by 2020.**

### *4.5 Biomass energy crops*

Biomass energy (for both heat and electricity) using forestry residues already makes a significant contribution to other Northern European countries – notably the Scandinavian countries, Germany and Austria – and in the US. However, the UK's very low forest cover limits UK available resource, and realisation of significant practicable potential would require development of dedicated energy crop plantations. DTI analysis suggests that energy crops could provide 33 TWh of electricity and this is based upon quite conservative assumptions about land availability. If these constraints are relaxed, technical potential becomes much larger – for example if 10% of UK arable land were to be utilised for energy crops, technical potential would be around 140 TWh/year (Bauen 2000). For this reason our analysis focuses upon energy crops.

In addition, for the purposes of this paper, assessment of biomass energy is restricted to direct utilisation of energy crops suitable for electricity generation and heat and does not include production of liquid biofuels (primarily ethanol and bio-diesel) for transport and other applications. The main reasons for this are as follows:

- In the UK climate, production costs of ethanol from crops such as sugar beet appear prohibitive (UNDP/WEC 2000, Bauen 2001). Ethanol production from lignocellulosic biomass may have longer term promise in temperate climates (UNDP/WEC 2000) but detailed assessment is beyond the scope of this paper.
- Production of biodiesel from annual crops such as oil seeds appears to have severely constrained technical potential given UK climate and land-use constraints, when considered from the point of view of total UK energy supply (DTI 1998), though may have significant value in niche markets.
- Biofuel production from imported feedstock is another possibility, however because of the constraints on domestic yield, biofuel production is excluded from further analysis here.
- The prospects for biofuels are discussed in the accompanying PIU working paper on transport.

### *Cost reduction potential – basis for assessment*

In many respects, potential cost reductions in delivered energy from energy crops are more difficult to assess than any of the other technologies considered here. In particular, the application of an overall learning curve to the 'seed to sub-station' system that delivers energy from energy crops systems is highly complex, and no such analysis is available in the literature. There are several reasons for this:

- Energy production from energy crops has three quite distinct cost streams, based upon very different technologies (indeed traditionally separate sectors) which militates against assessment based upon an overall learning rate, particularly whilst market experience is limited:

  - crop production
  - biomass harvesting and processing
  - and energy conversion (gasification and/or combustion)

- For key technologies and aspects of energy production from energy crops, market experience is severely limited and data sufficient for construction of learning curves is not available:

  - There is very limited experience in dedicated energy crop production of a type suitable for the UK climate, and this is equally true of crop processing and harvesting
  - Whilst 'conventional' combustion of biomass for heat and electricity is widespread in some countries, advanced biomass technologies, such as integrated gasification and combined cycle (BIGCC) plants are limited to a small number of demonstration plants.

For all these reasons we do not attempt to assess biomass energy crop cost reduction potentials using a 'whole system' learning curve as we have for wind and PV. Rather, cost reduction potentials for crop production and processing, and for two of the key options for energy conversion (conventional combustion and BIGCC), are discussed separately. We draw primarily upon engineering assessments, but also consider conventional combustion of biomass products for electricity generation, a well established technology for which a learning rate is available.

*Conversion Technologies*

Two basic approaches to biomass conversion for electricity and heat may be utilised:

1. Direct combustion technologies; from simple biomass burning for direct heat in a domestic boiler, stove or open fire, to large scale utilisation of biomass products such as wood chips for electricity generation, district heating and cogeneration (CHP). We focus here on commercial scale electricity generation and CHP plants.
2. Gasification of biomass products to provide gaseous fuel for a wide range of uses including large and small scale CHP, as a feedstock for fuel cells, and for heating systems. We focus here on a leading emerging application – biomass integrated combined cycle electricity generation (BIGCC).

*Crops*

The crop production technique that is of most interest in the UK context is short rotation coppice of fast growing trees such as willow. This technique provides a relatively high energy yield per area of land in the UK climate and is well suited to biomass production for power and heat, at present it appears that other crop types, such as grasses and oil-seeds are more suited to sunnier latitudes. Whilst this may change as new varieties are developed, SRC is the focus of this analysis.

*Issues in cost reduction for conversion technologies and crops*

*Conventional combustion technologies*

The use of biomass in conventional boilers for district heating, electricity generation and CHP makes a significant contribution to primary energy consumption in several countries. Biomass energy based on these technologies contributes around 4% of US primary energy, 11% in Austria, 20% in Finland, 17% in Sweden. Biomass for district heating and CHP is also well established in Denmark and Germany (UNDP/WEC 2000, Bauen 2001). Cumulative electricity production from commercial biomass is in excess of 100 TWh – biomass already has significantly more market experience than any other emerging renewable option (IEA 2000). Conventional combustion technologies for biomass fuels are closely related to coal fired combustion technologies and as such the technology may be considered ‘mature’. State of the art combustion plants for biomass electricity generation, running on agricultural and forestry wastes, currently deliver energy at around \$0.05 (3.5p) to \$0.06/kWh (4p) (UNDP/WEC 2000). The learning rate for electricity production from biomass (using conventional combustion) has been estimated at around 15% (IEA 2000).

Although a learning rate for biomass electricity production using conventional combustion is available, detailed cost reduction projections based upon this learning rate, for *conventional* combustion technologies alone, are not appropriate. The reasons for this are as follows:

- Development of larger and more efficient plant (replacing old and inefficient systems) underpins some of the 15% learning rate seen in recent years. Whilst this is an important aspects of learning and the trend towards larger plant is likely to continue, modern conventional combustion plants are already approaching theoretical limits on conversion efficiency.
- Potential for continued efficiency gain is a key driver of interest in gasification technologies and it would seem inadvisable at this stage to simply assume that the historic learning rate for conventional combustion technologies can be applied to gasification technologies - for reasons discussed below.
- Whilst considerable expansion of biomass electricity (primarily CHP) is planned in Denmark, Finland, Sweden and the US (UNDP/WEC 2000), detailed market growth data (both historical and projected) is not available.
- Reductions in biomass fuel costs are discussed below, and may be expected to continue to fall. However fuel cost reduction alone is unlikely to be sufficient to sustain a 15% learning rate.

All these factors suggest that overall cost reduction potential in biomass combustion technology over the time horizon of interest here cannot be assessed without attention to advanced combustion technologies, and to fuel costs, to both of which we now turn.

### *BIGCC*

Gasification of biomass feedstocks offers the potential of higher conversion efficiencies and reduced atmospheric emissions compared to conventional combustion technologies. Integrated gasification and combined cycle gas turbine plants (BIGCC) offer high efficiencies at a relatively small scale (~30 – 50 MW), which makes them suitable for decentralised generation – of particular interest due to the distributed nature of biomass crops and the relatively high costs of transporting biomass material.

BIGCC is currently at the pre-commercial demonstration stage. Pilot projects are operating in the UK, Sweden, the US and Brazil (UNDP/WEC 2000). With such a small number of operating projects learning rates are not available. However detailed engineering cost assessment of the Swedish and UK plants has been undertaken (Bauen 2000). The Swedish plant (a CHP scheme) delivers energy at a cost of around 4.7p/kWh and the UK plant (electricity only) at around 7.6p/kWh[13]. For both plants costs per kWh delivered are split roughly 50/50 between capital and operating costs – of which 72% are fuel costs (Bauen 1999). Capital costs of these early plants are much higher than those of conventional gas-fired plant. Engineering assessment suggests that capital costs could be reduced by half through replication and economies of scale once BIGCC plants enter early commercial application (Bauen 2000), this would reduce energy costs to 1.7 – 3p/kWh and 3.7 – 6p/kWh for the Swedish and UK plants respectively. The cost range reflects sensitivity to discount rate (8% and 15%)

It should be noted that these costs are estimates of the first ‘commercial’ applications – that is where the technologies move beyond one-off demonstration projects plants and begin to be installed in larger numbers. Further cost reduction would be expected as market size expands. However it is notable that the gasification process accounts for just 19% of total capital costs, whilst combustion technology costs account for around 35% (Bauen 1999). It is not clear how much scope for cost reductions in turbines – a much more mature technology – may be expected. Learning rates for CCGT technologies are less than 10% (IEA 2000), however market growth of turbines for BIGCC application would represent only a very small amount of existing turbine markets and as such it is difficult to assess BIGCC turbine cost trends in isolation. Overall, whilst it is clear that considerable cost reduction for BIGCC should be expected once the technology progresses beyond the early pilot stage, the long term trajectory of cost reductions is uncertain. The above considerations suggest that the potential for sustained cost reductions might be limited. Sensitivity to ongoing capital cost reduction is explored below.

Once capital costs are reduced to ‘early commercialisation’ levels, sensitivity to fuel cost and capital cost reductions become largely the same – energy costs are reduced by 10% for each 20% reduction in fuel costs or capital costs (Bauen 2000). If capital costs are reduced further then sensitivity to fuel costs will increase. It is to fuel cost reductions that we now turn.

*Crop Production*

World-wide there is very limited experience of energy crop production (UNDP/WEC 2000) of types suitable for UK application. Estimates of current costs suggest that energy crops may cost as much as $4(£3)/GJ in Northern European climates (UNDP/WEC 2000). This compares unfavourably with fossil fuels. However, costs are widely predicted to fall as experience with crop handling and processing increases and if yields are increased through crop development. Some estimates suggest that energy crop costs may fall to around $1.7(£1.2)/GJ (UNDP/WEC 2000, DTI 1998). Nevertheless the low energy density of biomass fuels compared to fossil alternatives suggests that handling and transport costs are likely to continue to impact negatively

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[13] Bauen quotes costs in 1995 Euros, all costs have been converted at 1995 £/Euro exchange rate (0.83) and inflated to 2001 prices (2.5% PA inflator). The lower cost of the Swedish plant results largely from the utilisation of heat energy available through CHP mode operation, raising overall efficiency

on the costs of biomass energy relative to fossil fuelled alternatives. In addition, photosynthesis has its own theoretical limits, which place restrictions on yield per area of land however much farming and crop varieties may be improved. In the absence of more detailed assessment we therefore take a figure of $1.5(£1)/GJ as the lower limit of biomass crop costs for the UK.

*Assessment of cost reduction potentials*

In view of the uncertainties surrounding cost reduction potential outlined above cost reduction potential for biomass energy crops is explored using three 'hypotheses'. The intention is to explore the impact of the central contentions discussed above: 1. To illustrate potential cost reductions should the historic learning rate for power production from biomass as a generic technology be sustained. 2. To illustrate potential impact of restricted capital cost reductions, and constrained biomass fuel cost reduction 3. to assess potential impact of restricted capital cost reduction with sustained fuel cost reduction:

1. Learning rate of 15% is sustained for generic energy crop technologies, and a market growth rate of 15% per year is assumed. This would imply a doubling of cumulative production every 5 years and a 60% reduction in current 'best' costs (currently for conventional combustion plants) from 4p/kWh to 1.6p/kWh by 2020. We make no judgement about conversion technology type, or about the split between crop costs and capital costs in delivering this reduction. However it should be noted that for all of the reasons discussed above, a continuation of the cost reduction trend and market growth in conventional combustion technologies (and hence costs this low) appears unlikely.

2. BIGCC technologies become dominant, however constraints on cost reductions for both capital and fuel costs reduce cost reductions below the historic learning rate for generic biomass technologies. Capital costs fall to 'early commercial' levels by 2010, with a 10% learning rate for capital costs thereafter, market size increases threefold between 2010 and 2020, fuel costs fall to $2.0/GJ, also projected for 'early commercial', but go no lower. This implies an energy cost of 3.7 – 6.0 p/kWh by 2010, thereafter sensitivity to capital cost reduction drives further cost reductions, each 20% reduction in capital cost reducing energy costs by 10%[14]. At this learning rate and market growth, capital costs fall by 30% between 2010 and 2020, and energy costs by 15%. This implies an energy cost of 3.1 – 5.1p/kWh[15].

3. As 2., but continued improvements in crop production techniques reduce fuel costs to $1.5/GJ by 2020, a 25% reduction. Using the same sensitivity to fuel cost reduction, this implies a further energy cost reduction of 12.5% - an overall reduction of 27.5 % on 2010 costs. This implies an energy cost of 2.7 – 4.3p/kWh.

**It is important to note that none of the above scenarios are projections.** Both market growth rates and the time it takes to reach 'early commercial' are pure (though

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[14] Based upon a 50% share of capital costs in total energy costs, Bauen, 2000

[15] 8% - 15% discount rate

reasonable) assumptions. However they do give us some indication of what could happen should engineering assessments of the potential for initial cost reductions prove correct, should the learning rate associated with generic gas turbine technology prove appropriate thereafter and if energy crop power production grows at a rate similar to the historical rates for wind and PV between 2010 and 2020.

The range of costs that these scenarios suggest is wide – **1.6 – 5.1 p/kWh**. In part this reflects sensitivity to financing assumptions, however whilst we can be fairly confident that costs would fall considerably once energy crop plants move beyond the demonstration phase, cost reductions thereafter are uncertain with current evidence. Evidence from international studies suggests that BIGCC costs could fall to around $0.04 (3p)/kWh in the long term (UNDP/WEC 2000). Both the high and low ends of the cost range appear to be less likely. The **central range of 2.5 – 4.0 p/kWh** appears likely to represent a reasonable range for costs in 2020.

### *Conclusions*

Application of learning curves to energy crop technologies is more complex than for wind and PV. Uncertainties over market growth rates, and constraints in the separate cost strands of conversion technology and crop production may make a continuation of the historic learning rate for biomass electricity inapplicable.

- **A range of plausible scenarios for the development of energy crop fuel costs and BIGCC capital costs suggest that costs in 2020 are likely to lie in the range 2.5 – 4.0 p/kWh.**
- **These cost reduction projections are less robust than for wind and PV.**

## 5. Summary of conclusions

*Onshore wind*

- Low cost wind sites are able to offer an average cost of electricity that is lower than current CCGT costs by around 2008.
- Learning curve extrapolations suggest that low cost wind sites would be able to deliver electricity at an average cost as low as 1 p/kWh by 2020. However some caution is required in interpreting this figure as engineering assessments tend to be less optimistic, hence;
- A cost range of 1.5p – 2.5p/kWh is reasonable for 2020.

*Offshore wind*

Engineering assessment and proxy learning curves (high cost sites onshore) suggest that the cost of offshore wind in 2020 is likely to be in the range 2.0 – 3.0 p/kWh.

The upper end of this range is conservative. It is important to note that:

If offshore wind is an extension of onshore wind development, with a similar, but separate learning curve – given a high rate of growth of offshore development;

- Offshore wind costs will tend to converge with those for onshore wind.

In addition;

- Developments offshore could extend learning and market growth for on and offshore wind, accelerating cost reductions in all wind applications.

*BIPV*

Projections based upon historic trends for market growth and learning rate suggest that;

- In the UK, PV will not become competitive with end user electricity tariffs until between 2020 and 2025.

- This neglects the potential for offset costs for building cladding, which may be significant and in appropriate buildings has the potential to dramatically improve the economics of BIPV.

There is some evidence to suggest that;

- Learning rates and market growth rates could be higher than projected.

And because of considerable potential for sustained cost reduction beyond 2020;

- Sustained development with a view to the long term is of particular importance for PV.

*Wave and tidal stream*

Attempts to apply a learning rate to wave technologies demonstrated that such an approach is not appropriate for a technology in such an early state of development.

Cost estimates using a parametric model of engineering costs suggest that costs of around 4.5 - 6p/kWh may be achieved for a number of UK designs. However, the level of development required to get to such a cost differs considerably between designs. Nevertheless, for leading designs, primarily nearshore devices;

- Costs of 4.5 to 6p/kWh are likely in the short term (3 – 4 years) for early commercial devices.

Modest market growth (25% pa), with a learning rate of 15% would be expected to deliver cost reductions of around 15% in the subsequent 3 to 4 years. Hence:

- Policy support sufficient to deliver market growth of 25% per annum in the period to 2008 – 2012 should deliver cost reductions equivalent to costs of around 4 to 5p/kWh within this timeframe for early commercial designs.
- This provides a 'target cost' by which success in wave developments may be judged, and continued policy support assessed.

Nevertheless, wide heterogeneity of designs is typical of innovative new products. Some designs offer larger technical potential, but are much further from commercial exploitation;

Longer term devices also need continued support with a longer time horizon, perhaps geared towards an expectation of early commercial deployment by 2020.

*Energy crops*

Application of learning curves to energy crop technologies is more complex than for wind and PV. Uncertainties over market growth rates, and constraints in the separate cost strands of conversion technology and crop production may make a continuation of the historic learning rate for biomass electricity inapplicable.

- A range of plausible scenarios for the development of energy crop fuel costs and BIGCC capital costs suggest that costs in 2020 are likely to lie in the range 2.5 – 4.0 p/kWh.

These cost reduction projections are less robust than those for wind and PV.

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## *Appendix 1*

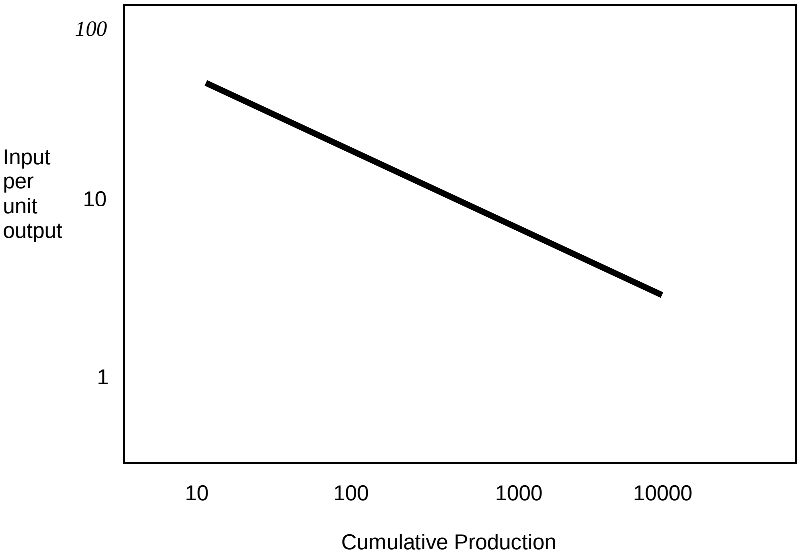
## Technological Progress and Learning Curves

1. There are many reasons why forecasts and policy scenarios are usually restricted to five or ten year time horizons. One important reason is that we know that over longer time periods technological change and progress can significantly alter costs and economic relationships. This problem has been subject to much study, particularly by the "world modellers" inspired by 'Limits to Growth'. One fairly robust way of handling technical progress in such modelling exercises is based upon the use of 'Learning Curves', also known as 'Learning by Doing', 'Experience Curves' and 'Learning Functions'.
2. A Learning Curve is a relationship between cumulative production and one or more inputs. A learning curve follows the mathematical equation

$$Y_x = K\, X^{-E}$$

where $Y_x$ = the input for the Xth unit of output
$K$ = a constant equal to the input for the first unit produced
$X$ = the cumulative production
$E$ = the learning index.

*Graphically the Learning Curve becomes a straight line on a log-log plot as illustrated below.*



3. The first learning curve was published by Wright[16] who observed a uniform percentage reduction in labour input with each doubling of cumulative production of aircraft. It was popularised by the Boston Consulting Group[17] and has been

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[16] Wright, T.P "Factors affecting the costs of Airplanes" *Journal of Aeronautical Sciences*, **3**(4) 1936 pp 122-128

[17] The Boston Consulting Group Inc, *Perspectives on Experience* Boston 1970

incorporated into standard economic theory[18]. There is a large body of literature providing evidence for its application to many manufacturing processes and accident rates.[19] It should be noted that the data fit with the learning curve is generally extremely good, $R^2$ values in excess of 0.95 are normal.

3.1. Learning Curves were extensively used in forecasting energy demand by the Systems Analysis Research Unit (SARU) at the DETR. They also used Learning Curves in the world model constructed in the late 1970s and in their Energy Demand Model[20] in the 1980s. In their Report the SARU team show Learning Curves for price reductions of a wide range of products including diodes, beer, low-density polythene, facial tissues and electric power. They also demonstrate that for many industry sectors the energy intensity (energy used per unit output) also follows a learning curve and this was used to predict future reductions in demand due to technical progress. This will be investigated further as a basis for long-term forecasting of reductions in industrial energy intensity.

3.2. The fact that Learning Curves appear to be ubiquitous in describing technical progress suggests that there may be an underlying mechanism at work. Peter Roberts, the leader of the SARU team, published a theoretical explanation of the Learning Curve in 1983[21]. Briefly the theory assumes that technical improvements are the result of a search for improvements amongst all possible changes. Most changes will reduce the efficiency of the process, only a subset will lead to improvements. Roberts argues that the search process becomes more restricted as more improvements are found – there is less likelihood of a change being beneficial. He demonstrates that the process is akin to searching the tail of a log-normal distribution that in turn leads to the derivation of the learning curve function. As an aside Roberts also argues that the learning curve can explain the logistic curve for substitutions between products (in particular fuels). He argues that the rate of substitution is governed by price differentials and that the logistic substitution arises when one product is reducing price as a result of increases in production i.e. the rate of substitution is governed by the price elasticity and rate of learning.

3.3. Rates of learning vary considerably with the learning index (E) varying between 0.1 and 1.3 in UK industries[22]. An alternative description of the Learning curve is made in terms of the "Progress Ratio", PR. The PR equals the ratio of the price for a given cumulative production divided by the price at half that cumulative production. Thus a progress ratio of 80% indicates that the price reduces by 20% with each doubling of cumulative output. The relationship between the Learning Index (E) and the Progress Ratio (PR) is that $PR = 2^{-E}$. Values for both parameters are shown in Table 1 below.

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[18] See for example Arrow, K, "The economic implications of Learning by Doing", *Review of Economic Studies* **29** (1962) p.155-173

[19] See for example Yelle,L.E. "The Learning Curve. Historical Review and Comprehensive Survey", *Decision Science* **10**(2) 1979 p.302-328

[20] "A simulation model for UK energy demand", SARU, Research Report 33, Dept.Environment and Transport, 1981

[21] Roberts, P "A theory of the Learning Process" *Journal of the Operational research Society,* **34** 1983 p.71-79

[22] See footnote 5 above.

**Table 1. Progress Ratio and Learning Indices**

| Progress ratio (PR) | Learning Index (E) |
|---|---|
| 90% | 0.15 |
| 80% | 0.32 |
| 70% | 0.51 |
| 50% | 1.0 |
| 30% | 1.74 |

4. Learning Curves provide a well founded framework for discussing the rate at which technical progress takes place and can therefore be used to predict when renewable energy sources meet specified cost targets. A recent publication by IEA[23] provides just such a framework. Its conclusions are discussed in item 5 below. There are other ways in which Learning Curves can be used to assist in the formulation of long-term scenarios. One use has already been mentioned, namely estimated reductions in energy demand due to technical progress. Another potential application is in estimating the reduction in cost of energy efficiency (or other resource productivity) measures. This is discussed under item 7 below.
5. The IEA held a workshop on the application of Experience Curves to Energy technology Policy in 1999 and concluded that they provided a robust tool for exploring low-carbon technologies for reducing $CO_2$ emissions. The work reported in the book is drawn from many different studies and indicates the learning rates that apply to renewable and other energy technologies.
   5.1. The progress ratios for renewable technologies given in the IEA book are summarised in table 2 below. These figures are broadly consistent with the learning rates documented by other authors[24].

*Table 2. Progress ratios for renewable energy technologies*

| | Europe | USA | Elsewhere |
|---|---|---|---|
| Photovoltaics | 65% | 82% | |
| Wind power | 82% | 68% | |
| Biomass (electricity) | 85% | | |
| Ethanol production | | | 80% |
| Supercritical coal | 97% | | |
| NGCC | 96% | | |

   5.2. The IEA study points out that it is possible to use the Learning Curve to estimate both the investment required to bring a new energy technology to cost-effectiveness and, given information on rates of investment, hence estimate the break-even time. The analysis is based upon the diagram reproduced as Figure 2 below. The shaded area indicates the cumulative output that must be produced before the technology reaches the break-even point. T, marked as the "learning investment". Broadly the sooner that investment is made the earlier the technology reaches cost-effectiveness. The

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[23] *Experience Curves for energy technology Policy*, International Energy Agency, OECD 2000. Note that because a copy was purchased on-line there is an electronic (PDF file 1.2Mb) version of the book available to PIU team members. Rob has a copy and Jake can send one.

[24] See the review ; McDonald,A and Schrattenholzer,L. "Learning Rates for Energy Technologies", *Energy Policy* **29** (2001) p 255-261. Also see Grubler,A et al "Dynamics of energy technologies and global change" *Energy Policy* **27(5)** (1999) p 247-280 and Oliver,M and Jackson,T. "The market for solar photovoltaincs" *Energy Policy* **27(7)** (1999) p.371-385

book strongly recommends supporting emerging technologies in niche markets where they *already are cost-effective* for some special reason e.g. use of PV in remote areas.

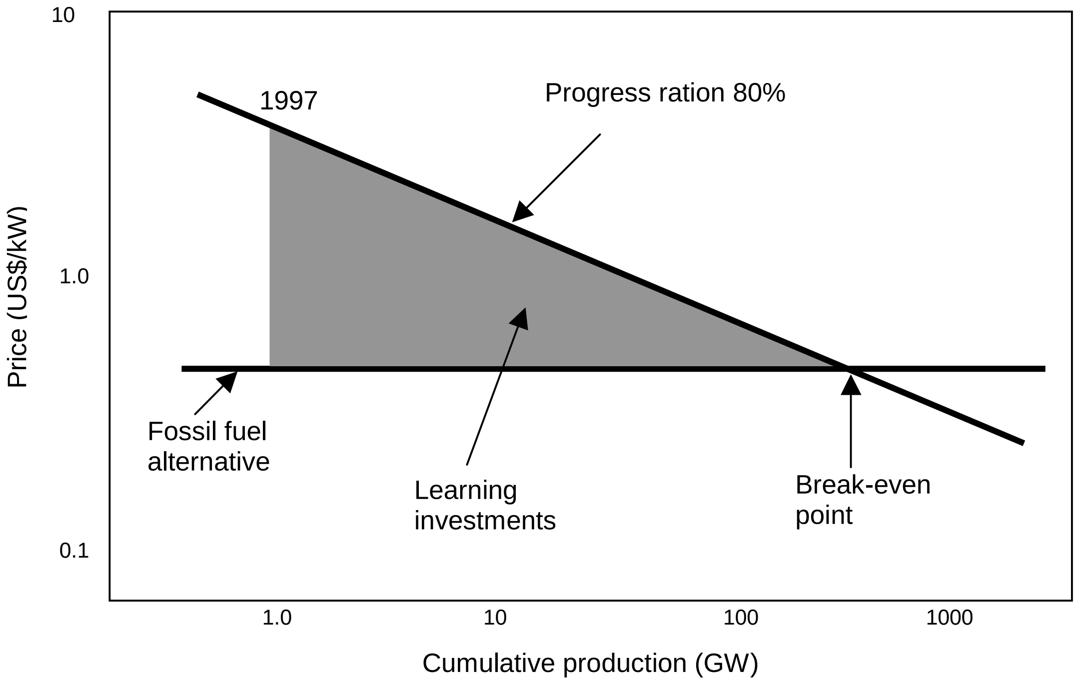

*Figure 2. Making photovoltaics break-even*

5.3. The main conclusions in the book are worth quoting verbatim since they are directly pertinent to the approach and objectives of the current PIU study.

> "A general message to policy makers comes from the basic philosophy of the experience curve. Learning requires continuous action, and future opportunities are therefore strongly coupled to present activities. If we want cost-efficient, $CO_2$ -mitigation technologies available during the first decades of the new century, these technologies must be given the opportunity to learn in the current marketplace. Deferring decisions on deployment will risk lock-out of these technologies, i.e. lack of opportunities to learn will foreclose these options making them unavailable to the energy system. From this point of view, the present success of the increasingly efficient combined-cycle technology may significantly reduce $CO_2$ emissions from the electricity sector until 2010, but may prove fatal for new non-fossil electric technology after 2010. Focusing policy measures in the period of 2008-2012 may severely restrict options beyond 2012.
>
> The encouraging result from the modelling experiments here is that portfolios of new technologies can drastically reduce the total cost for the transition to a low-carbon economy by the middle of the new century. However, the low-cost path to CO 2 -stabilisation requires large investments in technology learning over the next decades. The learning investments are provided through market deployment of technologies not yet commercial, in order to reduce the cost of these technologies and make them competitive with

> conventional fossil-fuel technologies. Governments can use several policy instruments to ensure that market actors make the large-scale learning investments in environment-friendly technologies. Measures to encourage niche markets for new technologies are one of the most efficient ways for governments to provide learning opportunities. The learning investments are recovered as the new technologies mature, illustrating the long-range financing component of cost-efficient policies to reduce $CO_2$ emissions. The time horizon for learning stretches over several decades, which require long-term, stable policies for energy technology.
>
> ….
>
> An efficient policy package should support the creation or exploitation of niche markets, where the specific properties of the technology are given a price premium. Experience curves are tools for designing entry and exit strategies for public policy interventions on such markets. The Japanese photovoltaic systems programme demonstrates how interventions are used to set up the niche markets, but also how experience curves are used not only to provide a definite target for the intervention, but also to design an exit strategy for the direct subsidies.
>
> > There are only a few explicit examples of the use of experience curves for energy technology policy analysis. Only a few measurements of experience curves for energy technologies are reported in the literature, and these measurements are concentrated in a few technologies. The lack of information and activity is surprising, both in view of the wealth of data and the use of experience curves in other technology areas and in view of the potential benefits to public policy making.”

6. Earlier reference was made to using Learning Curves for predicting the rate at which the costs of energy efficiency measures decrease. These are of interest in their own right and may also shed light on the role of technical progress in the general area of resource productivity. Estimating learning indices requires good price data over at least one order of magnitude of cumulative production, preferably more. Prices are subject to inflation, which can be corrected, and also to fluctuations due to business cycles, interest rates and so on. Good time series data is required to reduce the impact of these short-term fluctuations. Unfortunately there is a dearth of data available on energy efficiency measures over a long enough period.
   6.1. There is data on loft insulation, for example in the study carried out by Shorrock on the effectiveness of grants[25]. However the data is confounded by the changes in standards over the period. In the late 70s the standard thickness of loft insulation was 75mm, this increased to 100mm in the 1980s and to 150mm by the mid 1990s. The data does show learning taking place since the adjusted cost of loft insulation in 1975 is similar to that in 1999, by which time the thickness installed had been doubled. Further evidence that loft insulation has become cheaper (at least relative to energy prices) is that the economic thickness of loft insulation (as for example recommended in Part L

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[25] Shorrock,L.D. “An analysis of the effect of Government grants on the uptake of home insulation measures” *energy Policy* **27** (1999) p.155-171

of the Building Regulations) has increased from 50mm in the late 1970s to 200mm in the 1990s and to 300mm in the proposed new Regulations.

6.2. Cavity wall insulation (CWI) provides a reasonable data set since cumulative production (equal to total installations) increased from 375,000 in 1975 to 3,967,000 in 1995. The difficulty with CWI is establishing the “price”. This is known to vary significantly between individual and contract prices and on time of year. Using typical figures of £125 in 1975 and £350 in 1995 the calculated Progress Ratio is 88%. This implies a reduction of just over 10% in real price with every doubling of cumulative production. This is a relatively slow rate of learning and may be typical of the home insulation industry.

6.3. Much higher rates of learning are expected to apply to products such as compact-fluorescent-lamps and condensing boilers since these are the result of industrial processes where Progress Ratios of 60-80% are common. However to date no good data has been obtained.