

Costs of low-carbon generation technologies

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Committee on Climate Change

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Executive Summary

Study context, aims and approach

Mott MacDonald was commissioned by the Committee of Climate Change in November 2010 to undertake a bottom-up, albeit high level, analysis of the current and future costs of renewable and other low carbon generation technologies. This report represents a summary of the draft findings focusing on the current cost build-up and the future drivers for these technologies (Tasks 1 and 2 under the Economic Review of Renewables, TOR). It draws upon the results of a parallel analysis by Oxera Consulting of the appropriate current and future discount rates for evaluating the levelised costs of low carbon technologies (Task 3 of the Economic Review).

The report is the culmination of a wide ranging review of the current status and cost drivers affecting all the significant low carbon generation technologies in the UK and the prospects out to 2050[1]. It has simultaneously involved considerable amount of work in developing a modelling framework to handle the diversity of drivers and assumptions (including technology deployment scenarios). A new technology capex model has been developed and the previous Mott MacDonald/DECC levelised cost model has been reformulated such that it draws upon these capex results to provide estimates of opex costs and fully built up levelised generation costs.

The main aims of the study are to examine the build-up of capital costs and operating costs and ultimately levelised costs of low carbon generation technologies, and their evolution over the next several decades differentiating between learning effects and exogenous drivers. All the costs and prices are quoted in 2010 money unless otherwise stated.

We have adopted a building block approach, starting with capital costs (which are typically the largest component for renewable and low carbon technologies), then factoring in the key non-fuel operational costs and key performance parameters (energy availabilities, efficiencies, etc) to derive levelised cost estimates. We have used a revised version of the existing DECC/MML model and as before drawn upon the latest publicly released DECC assumptions on fuel and carbon prices. In contrast to the previous DECC analysis we have used differentiated discount rates as derived from the Oxera analysis.

The remainder of this summary considers the main themes in assessing current and future capital costs and building up levelised costs. It then reports on the main findings in terms of capital costs and levelised costs for the current position and the future.

[1] This report only presents figures to projects starting construction in 2040. The database and model include projections to 2050, and even beyond..

Assessing current capex

We estimate current capital costs using an engineering cost approach, typically comprising six to seven line items, specified for each technology group

In a few cases data have been taken from actual recent projects, however for many technologies we had to rely on tender prices and supplier quotes. For early stage technologies with no commercial scale deployment we relied on estimates based on comparator technologies and engineering studies.

The estimates also include a market “congestion premium” (or discount) in the case where prices differ from the level that would return a normal profit to equipment and service providers. This market price “distortion” (mark-up/ discount) has been estimated on the basis of our knowledge of recent transactions, reference to comparator technologies/ jurisdictions and discussions with the Original Equipment Manufacturer (OEM) and developer community. Where possible we have attempted to differentiate what components carry this premium (or discount).

For the early stage technologies we have assumed a hypothetical commercial scale plant, based on current pricing but extrapolated supply chain capability. In practice, such a plant could only be started in 2-4 years from now, and with great effort. This is so that we have a more sensible “initial value” than comparing with early stage demonstrations. This applies for CCS, wave and tidal stream, and even nuclear to some extent.

Even for more established technologies there are issues of what counts as a representative project, since costs and performance often depend on site conditions/ feedstock considerations/ etc: very few technologies produce identical installed plants with identical performance.

All these factors make the estimates of current capital and levelised costs hugely uncertain. The analysis of future costs is even more “assumptions heavy”.

Assessing future capex

The traditional view is that future capital costs will be influenced by the extent of learning by doing, technology advances and increased scale economies, all of which are clearly linked to deployment. These factors can be combined into a single learning effect often represented by so-called experience curves which link rate of cost reduction to cumulative deployment. The learning rates vary according to the type of technology. We have applied this approach as a supplementary one to our main approach which relies on subjective techno-economic assessment based on MML’s judgement. MML’s view has been informed by wide engineering and commercial exposure to many technologies on a global basis and contacts across the developer and supplier communities.

The above learning effects have been modified by a set of exogenous factors, which are largely unconnected to learning, such as already mentioned market congestion. Other such factors include raw material prices, competition from low cost jurisdictions, and technological advances.

These capital cost estimates and projections become the first building block for the estimation of levelised costs. Adding on an estimate for fixed operations and maintenance costs, variable non-fuel operations, and where appropriate the fuel and carbon prices and CO_2 transport and disposal costs, produces the cost stream for each technology. This cost stream is then represented in NPV terms (discounted by the appropriate discount rate for each technology). Dividing this NPV of costs by the discounted stream of net generation, (which will depend on the degradation profile, availability level, load factor and auxiliary load), provides a levelised cost expressed in £/MWh.

Any estimates produced from such an analysis will necessarily be uncertain given the possible combination of input assumptions. We have explored the implications of this uncertainty, through a simple scenario approach, which has involved looking at the business and regulatory environment for the technology groups under three archetypal scenarios:

- A balanced efforts scenario (where nuclear, CCS and renewables are all supported)
- A high renewables scenario, where renewables and energy efficiency are supported, but nuclear and CCS are largely blocked;
- A least cost scenario, where the focus is on technologies appearing to offer low costs from a near term viewpoint. We have assumed, only low cost renewables and energy efficiency would be supported, along with nuclear and gas-CCS.

These scenarios embody a different mix of deployed capacity, progress in cost reduction and technology risk perceptions. This drives our learning assumptions.

In all three scenarios it is assumed that the deployment drivers apply equally to global and UK contexts, although the doubling ratios applied in the experience curve approach are not the same. In practice, it is possible that the UK will not be in full alignment with global trends, and this will have different implications depending on technology. For instance, it is likely that the UK could still gain considerably from an independent offshore wind programme than a stand alone nuclear programme.

The same scenarios have been used by Oxera to generate a set of differentiated discount rates that were then applied in the levelised cost build up here. Since these discount rates tend to move inversely with deployment and risk perceptions, this has the effect of amplifying differences.

All these scenarios are aspirational in the sense that they would provide very deep reductions in GHG emissions. We have not considered a business as usual scenario, which would show a slower rate of emissions decline and almost certainly more modest cost reductions than indicated in this study.

Assessing operating costs

Fixed operation and maintenance (FOM) costs tend to be linked to capital costs of the plant, such that annual fixed opex amounts to between 1% and 6% of the initial capex. The definition here excludes insurance and grid charges and any share of central corporate overheads.

Solar PV is an exception in that annual maintenance is very low, generally well under 0.5%. The variation between technologies reflects the level of automation of the technology, its reliability and the ease with which it is possible to repair and service it. Typically it is the technologies which have complicated mechanical handling equipment such as solid fuel and ash handling systems, and/or complicated and vulnerable high pressure parts (boilers) that require the highest level of manning per kW. Clearly, because of the workings of economies of scale, smaller plants of the same general type tend to have higher staffing levels. This means smaller solid biomass fired plants tend to have among the highest FOM share. Offshore wind is another technology which is characterised by a high FOM almost entirely because of the extra costs of servicing in an offshore setting – there is no operational team on continual shift, though some offshore substations will have 24x7 cover.

Given that the FOM are a fixed share of initial capital cost these costs can be expected to fall in proportion with capital costs as a technology becomes more mature. The learning curve literature tends to show that non fuel operational costs have tended to fall at the same rate as capex costs. This suggests that there is not a strong case for adding an additional learning effect. However, it is widely observed that for many emerging technologies, fixed operating costs may decline over the life of the plant. For some technologies, towards the end of the plant life, costs may increase as the plant becomes more unreliable.

Variable operations and maintenance (VOM) costs (typically expressed as £/MWh) comprise some incremental servicing costs (rather as the car servicing agent replaces certain parts after particular mileage is reached, or as its condition fails to meet compliance requirements - like tyre treads. These VOM costs can be significant for gas and clean fuel fired plant and for some renewable plant that suffers from wear and tear, such as hydropower plant. Typically, wind and solar plants are seen as having zero variable costs. The other big set of items for VOM is the cost of purchasing and disposing of various materials required or generated in the production of electricity. The obvious examples on the input side are sorbents, catalysts and reagents used in coal and gas plants for CO_2 capture, while on the output side there are various residues that need to be treated and disposed of. Water treatment is another variable cost for many types of plants.

There is no clear evidence of how VOM costs of the main technologies have moved over time. It is likely that technological advances should have reduced costs as plants have become more reliable (like cars) however, the increased complexity of plants, with the add-on systems (emission controls, residue disposal, etc) has increased the need for purchasing specialist chemicals and broadened the range of condition monitoring. Our central assumption for modelling purposes is that there will be a negligible reduction from the current VOM levels.

Fuel and carbon price assumptions for the analysis in this study are taken from DECC's latest published projections, and indeed remain the same as those used in DECC Generation cost update report of 2010. The fuel prices are based on firming oil and gas prices but steady and lower than current coal prices, such that coal has a significant cost advantage versus gas (and oil products). Carbon prices under the central projection increase slowly until 2020 and then rise strongly through to 2040, when they reach £135/tonne of CO_2. The fuel costs are applied to all the fossil fired plant, nuclear plant and biomass plant fired on non-waste feedstocks. Carbon costs are applied to all fossil fuel plant (including those fitted with CCS equipment) on the basis of their emission factors.

Main findings

Current cost drivers

Looking at capital cost drivers first:

There is a significant difference between quoted prices and underlying costs for a number of technologies. A market congestion premium plays a significant role in elevating current levelised costs of certain technologies, especially coal, nuclear and offshore wind, where we consider the premium is of the order of 20%.

For early stage technologies, such as CCS, wave, tidal stream, biomass gasification and even nuclear, the capital costs are extremely uncertain.

For some technologies project specific conditions, such as site/location, feedstock, technology type and capacity rating, can affect the specific capital costs and often performance parameters (for which there may be trade-offs, with higher costs leading to improved performance).

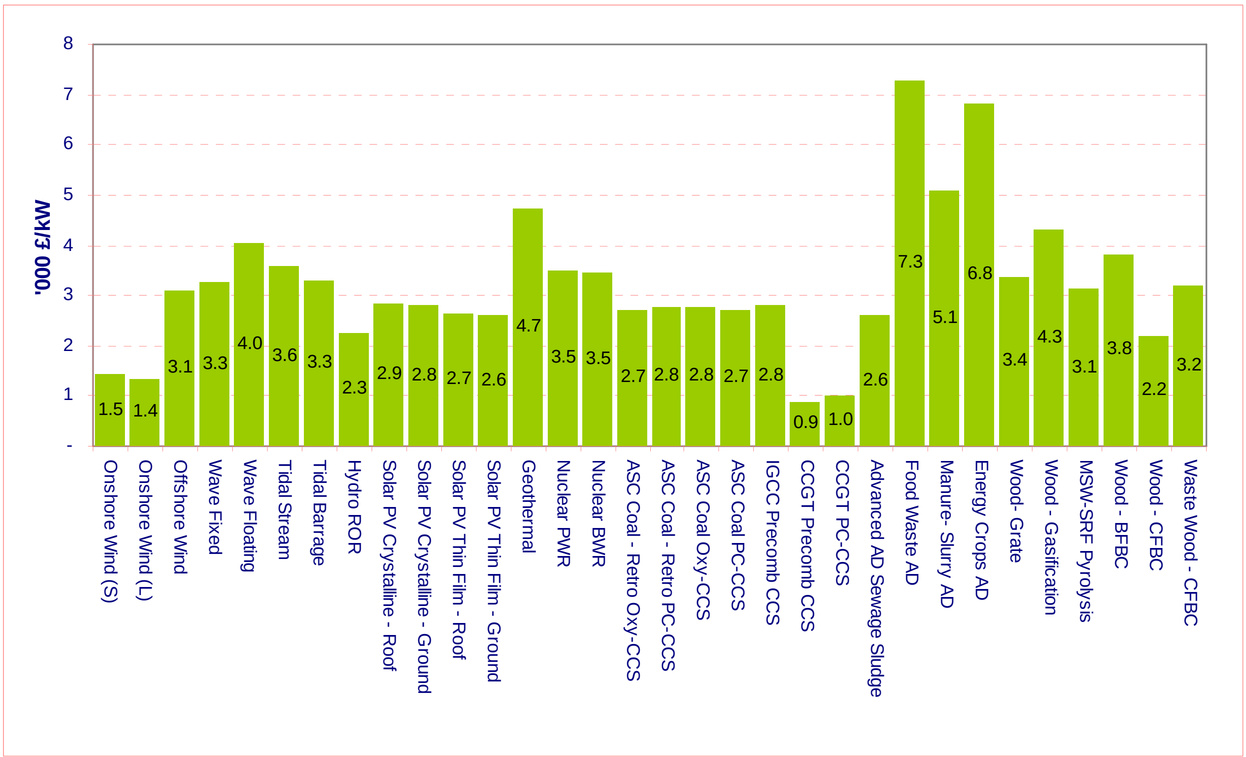
The prime mover[2] is typically the largest item for renewable technologies, however its share varies considerably depending on the extent of civil support/containment structures and feedstock treatment (for biomass). For instance, for onshore and offshore wind the wind turbine generator accounts for about 75% and 45% of total capex, respectively. For nuclear, coal and gas CCS, the prime mover is typically a smaller share.

Raw materials and energy prices are not significant drivers of capex. Raw materials inputs tend to be less than 5% in most cases, with energy a similar amount. Labour tends to be the largest item, with onsite labour accounting for a particularly high share for technologies requiring a large amount of civil works and on-site assembly (such as nuclear, coal and tidal barrage). For technologies where assembled modules are simply put in place, the labour input is embodied within the module.

Figure 1 shows our central estimate of current capital costs including any market congestion premium. For most technologies, the costs fall in the £2000-3200/kW band. Onshore wind has lower costs, at £1350-1450/kW. In addition, we estimate that in principle, a gas fired CCGT equipped with carbon capture (based on post combustion) could be built for around £1000/kW. However, this technology has not yet been demonstrated at utility scale. Mini hydro (based on run-of-river) and large wood fired boiler (CFBC) are estimated to be in the £2000-2400/kW band. Solar PV costs fall in the £2600-£2850/kW range. Coming just above this at £2900-3200/kW is offshore wind, coal CCS and nuclear. At the higher end, there are a number of very early stage and small scale technologies such as wave and tidal stream and various bio-energy technologies (gasification, pyrolysis, wood grate, etc).

[2] This is the main energy conversion device.

Figure 1: Current Capital Costs in £000'/kW installed



Source: Mott MacDonald

Discount rates

In this analysis levelised costs are to be estimated using discount rates that are differentiated according to developers' and lenders' perceptions of risk and ability to raise debt. These estimates have been derived by Oxera Consulting, as described in their report to CCC, "Discount rates for low carbon generation technologies" published at the same time as this report (May 2011). These are shown in Table 6.6 and Table 6.7.

Discount rates have been estimated for the same three archetypal scenarios used to drive the application of learning rates for the technologies in this study. Oxera's estimates for current rates show significant band of uncertainty for all technologies from 3-5 percentage points, with the mid point of the individual ranges resulting in discount rates from 7.5% to 15.5%. At the bottom end are CCGT (without CCS), onshore wind, mini hydro and solar PV while at the top end are wave, tidal stream and CCS technologies. The midpoint rates for nuclear and offshore wind are 11% and 12%, respectively. All discount rates are presented as expected real, pre-tax returns to debt and equity capital.

Looking forward Oxera is projecting that under scenarios where a technology faces a supportive business environment and deployment rates are high, then discount rates could fall by up to 5% between now and 2040. Technologies that are already established and that are low risk could see a reduction of less than 1% in their discount rates over this period. The implication of this is that comparison between the levelised costs of two technologies with similar capital costs but very different investment climates would lead to substantial differences in cost. As mentioned before this factor is compounded given that the capital costs would have been on different improvement trajectories. The implication is that financing terms are a critical factor in influencing levelised cost movements for low carbon generation technologies.

It is important to note here, that we are only exploring uncertainties relating to the risk premiums for the technologies. The projections include a modest decline in the risk-free rate, but we are not considering uncertainties regarding this element of the cost of capital, which in practice could be substantial.

Current levelised costs

The capital cost, financing and operating cost assumptions are brought together in the levelised costs analysis. The hierarchy of capital costs mentioned above is only partly reflected in the levelised costs estimates, which reflects the differentiated effects of opex and fixed cost dilution arising from plant and energy availabilities. F shows the estimated current levelised costs. These estimates use the central case assumptions from the Oxera analysis on discount rates which are differentiated by technology.

The least cost options appear to be two biomass waste options, advanced AD sewage and pyrolysis of MSW/SRF, which have levelised costs of £51/MWh and £73/MWh, respectively. Both assume no gate fee and full baseload operation. Of the more widely applicable options, onshore wind has the lowest costs at £83-£90/MWh.

Nuclear (£96/MWh), wood combustion (based on CFBC - £103/MWh) and Gas-CCS (£100-105/MWh) all provide a lower levelised cost than offshore wind (£169/MWh). But all three would probably need a large first of a kind (FOAK) contingency added to provide comfort for bankers. Coal-CCS is also estimated to provide a lower levelised cost than offshore wind at about £146/MWh, which is a substantial premium (£35-40/MWh) over gas-CCS. Much of this premium reflects the currently elevated prices of coal equipment versus CCGTs.

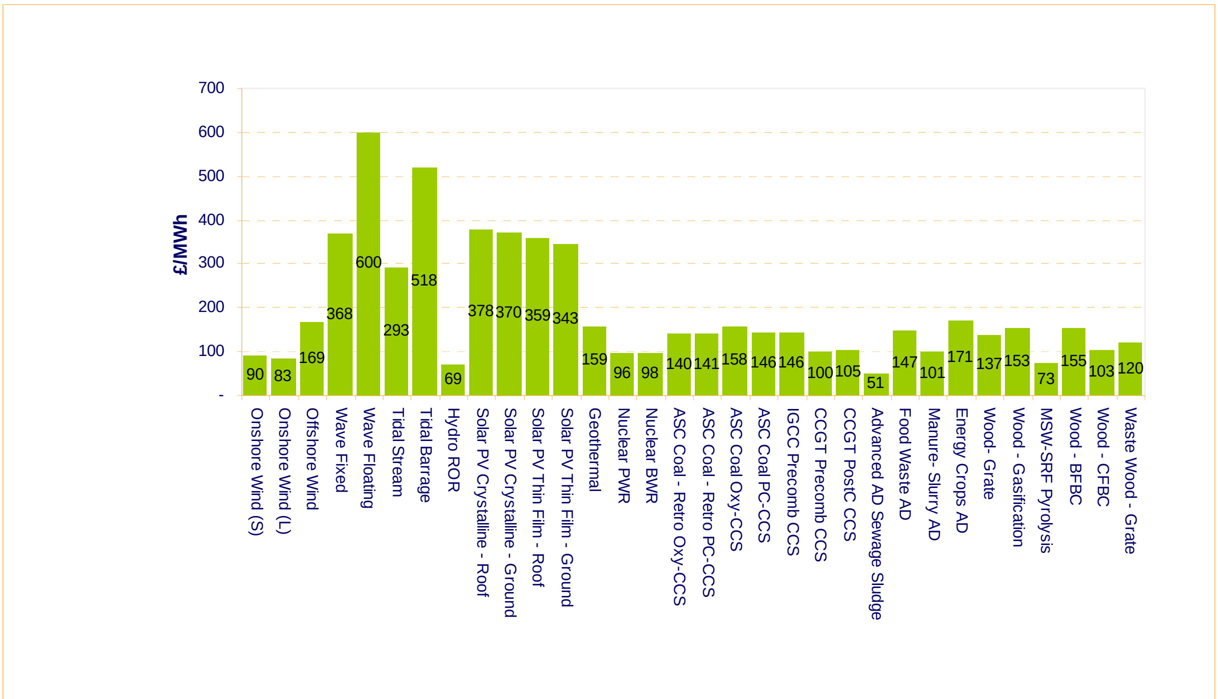
Of the other low carbon technologies now being considered for wide deployment, solar PV is quite clearly very expensive at £343-378/MWh. This reflects the early stage of this technology and the low annual capacity factors (~10%) achievable in a UK setting.

There is a big variation in the costs of AD applications – as mentioned already AD sewage is easily the least cost at about £51/MWh. This reflects minimal additional feedstock treatment (beyond that built into the sewage treatment works). Others require significant feedstock treatment/ complicated handling and so their costs range between £100/MWh (manure/slurry) and £171/MWh (energy crops). In all cases gate fees for waste feedstocks are assumed to be zero. AD systems fed on energy crops include the biomass purchase cost.

Of the other bio-energy applications, the smaller wood based technologies tend to have comparatively higher costs with small BFBCs and advanced gasification both around £155/MWh.

There are no commercial scale floating wave and tidal stream installations in place so our cost estimate is based on a technical assessment. Our view is that tidal stream would offer considerably lower levelised costs, on the basis of the higher fixed cost dilution, as tidal stream offers an annual capacity factor of 35-40%, versus around 20% for a floating wave device. As mentioned earlier the capital costs are likely to be comparable. On this basis the levelised cost of tidal stream and floating wave are £293/MWh and £600/MWh, respectively.

Figure 2: Current Estimated Levelised Costs



Source: Mott MacDonald

Future capital costs

Our judgement based assessments and the application of experience curves both indicate substantial reductions in capex for most technologies. There is generally a consistent story between the two techniques, but there are a few exceptions. Most notably, for nuclear, the “learning rates approach” leads to a much less significant cost reduction than MML and its polled experts believe is likely. Nuclear has the lowest learning rate and also the lowest doubling multiples. The former reflects the poor track record of nuclear projects in the past, which often faced changing health and safety regulations which compromised construction schedules. The comparatively low growth reflects the relative maturity of the technology. The judgemental approach recognises that the latest versions of UK nuclear plants will be first of their kind within the UK so there should be considerable scope for cost reductions from learning in the early deployments. This would be especially so if there were series ordering, in which case the supply chain capabilities could be augmented.

MML is also more bullish on CCS than the learning rates would indicate, despite the huge uncertainty. We believe that the prospect of a collaborative approach to technology development, due to the public funding and the recognition of CCS as global strategic initiative, will lead to faster learning rates than the past learning seen in refining or FGD. Also, across a wide range of technologies, there is the scope for spin-off benefits from advances across microelectronics, nanotechnology, additive manufacturing and biotechnology.

We generally have greater confidence in the technical engineering judgement for early stage technologies, as compared with the numbers generated from applying learning curves, though of course there remains much greater band of uncertainty for these technologies. This reflects the arbitrary nature of selecting initial starting points in terms of cost and deployed capacity, as well as the uncertainty of deployment projections. The choice of appropriate comparable learning rates is not the main challenge here.

In addition to these learning effects the study considered a number of other exogenous drivers.

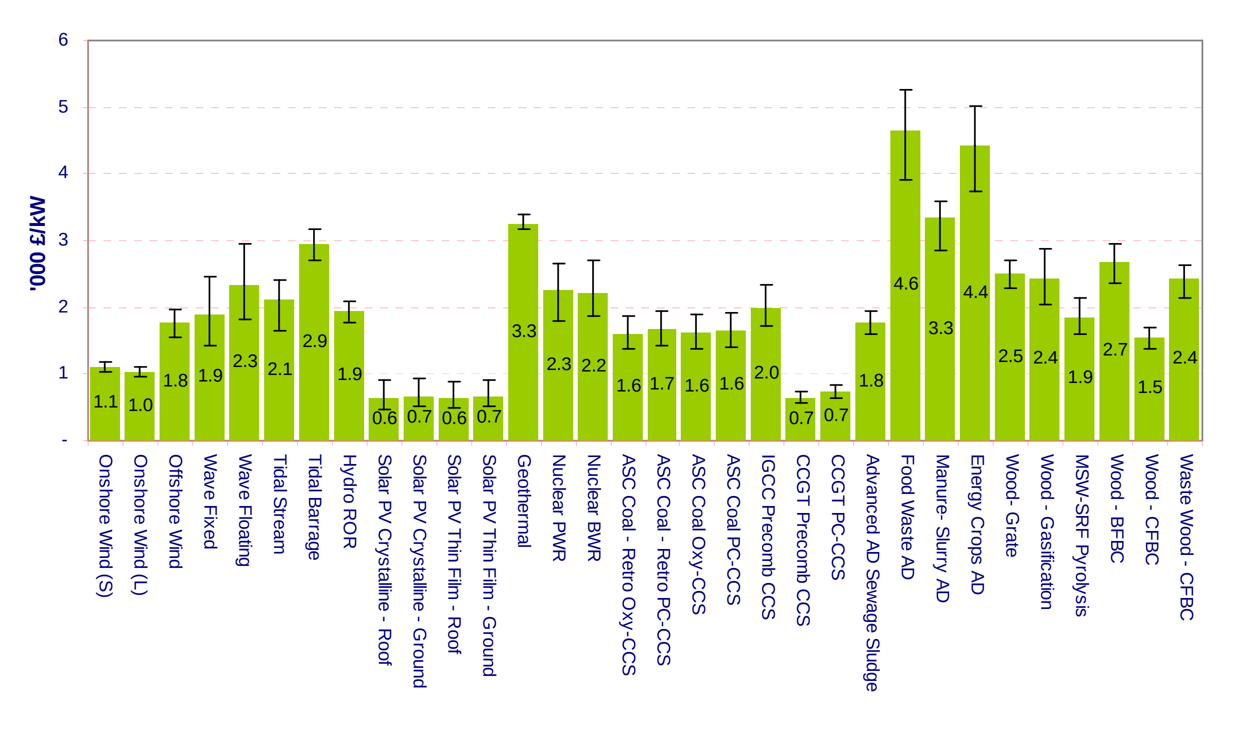
- The extent of market congestion will clearly depend on the balance of supply and demand in each market segment. We have taken the view that the market will rebalance in the long term. In practice, there may be periods of scarcity and surplus which would drive a large wedge between prices and underlying costs.
- Similarly, we have assumed that exchange rates remain fixed at current levels in real terms. We recognise that in recent years fluctuations in the sterling exchange rate (versus the Euro and US dollar) have accounted for significant movement in equipment prices for WTG and gas turbines, for example. However, we leave it to readers and others to make judgements about future exchange rate.
- Raw material and energy costs constitute a comparatively small component in capital costs (together generally under 10%), hence movements in these variables is likely to have a moderate effect. In fact, in many cases, scaling up the size of technologies results in a big reduction in material intensity per kW installed. Our working assumption for the scenarios tested here is that raw material prices would remain fixed

in real terms. The implication of these two factors is that the material costs expressed per kW of capacity are projected to decline. We have not explicitly separated out energy costs, however we suspect that the movement in energy intensity per kW would broadly match those for material intensity.

- Competition from low cost jurisdictions has not been a major driver to date in power equipment markets and in electricity production. However, it is clear that there are big differences in costs between the costs of components and fully installed plants in China (or other low cost jurisdictions) and the UK. While it is not possible for the UK to access the low (on-site) installation costs, given its much higher labour costs, it is likely that the UK will gain from sourcing components and even some assembled major modules (for instance, wind turbine nacelles and solar PV modules). This is likely to come initially via components outsourced from western OEMs, but later OEMs from China and other low cost jurisdictions.
- Technological breakthroughs and advances can also be considered to have a certain degree of independence from the endogenous learning, which is more concerned with functional design changes and assembly processes. The acceleration in the rate of advance in microelectronics, biotechnology, nanotechnology is bringing breakthroughs in materials and production techniques which are likely to benefit current and early stage technologies alike. This provides perhaps a more powerful backdrop for suggesting that past learning rates may understate what is to come.

The combined affects of all these drivers is that we should expect very significant capital cost reductions through the next decades. Our own projections strip out the effects of market congestion, exchange and raw material price impacts and focus primarily on the learning and supply chain effects. In making projections we have taken a cautious view that change will be smooth, therefore we have not allowed for major technology breakthroughs (jumps) or deep costs reductions through outsourcing the whole supply chain to low cost jurisdictions, though we have commented on these drivers. Even without these factors, the incremental process of improvement is projected to bring substantial cost reductions. This will clearly be most noticeable for solar PV; where capital costs are projected to fall to a level which solar PV would undercut all other technologies expressed in £/kW terms sometime between 2020 and 2030 depending on the scenario. Most other technologies will see more moderate reductions of 20-40% in real terms over the next three decades. A few early stage technologies, such as tidal stream are projected to see more marked reductions (~50% for tidal stream. Figure 3 shows the range of capex costs in 2040 across the three archetypal scenarios.

Figure 3: Projected capital costs starting construction in 2040 in £'000/kW installed



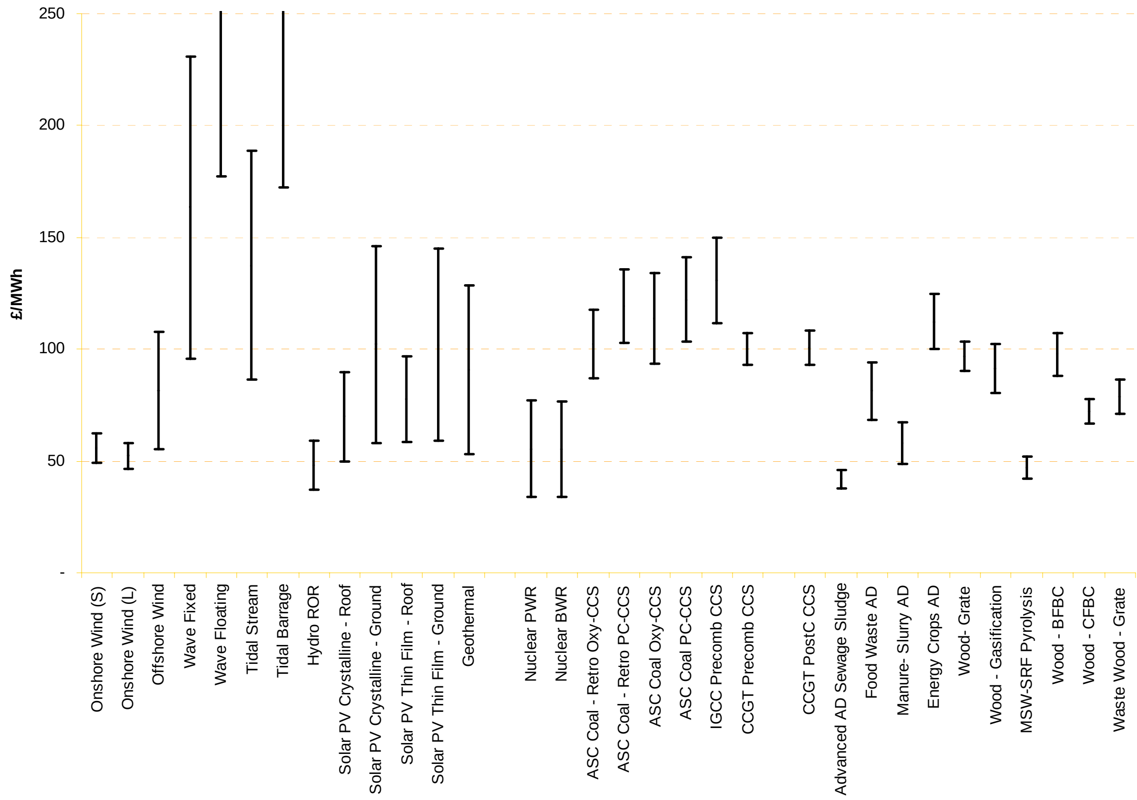
Source: Mott MacDonald

These falling capital costs provide a downward force for levelised costs. This contrasts with fuel and carbon costs, both which are generally expected to be on upward trajectory. This suggests that the premium necessary to achieve low carbon should fall over time.

Future levelised costs

Overall, the picture is one of falling real levelised costs for low carbon technologies. The relative movements of different technologies are largely driven by differential learning rates and deployment projections. This implies that the selection of scenario can play a significant role in a technology's relative position. With this caution in mind we have commented on the main themes by technology group, while Figure 4 summaries the results.

Figure 4: Projected Levelised costs for projects starting construction in 2040



Source: Mott MacDonald

Mini hydro and onshore wind are projected to remain low cost in all the scenarios, with costs in 2040 of about £45/MWh and £52-55/MWh, respectively. Unlike for offshore wind, there is little prospect of scale benefits, and modest scope for technology improvement, other than through rationalised production techniques and supply chain upgrades.

Offshore wind is projected to see significant cost reduction over the next decades as the technology is scaled up, despite the move further offshore and into deeper waters. Moving to a large windfarm based on 10MW machines in 2020, versus 5MW currently, would allow significant savings in the WTG itself as well as in the foundations and electrical connection. With a further scale-up projected for 2040 (to 20MW) there would be more savings on all the items. This assumes that the offshore equipment, installation contractors and service markets are not subject to serious congestion, as has been the case in recent years. It also assumes that by 2040 new material technologies will allow the larger structures to be built (assuming we stay with horizontal axis) or new vertical axis designs will be deployed. We have assumed a jacket structure for 2040, however, it is likely that some form of floating platform will offer a comparable or lower cost solution by that time. Overall, we are projecting that levelised costs will fall to £120-130/MWh and £100-130/MWh in 2020 and 2040, respectively.

Solar PV sees huge reduction in costs but only gets close to offshore wind and nuclear by 2040. This is despite huge reduction in capex to under £400/kW in the most aggressive scenarios by 2040, and reflects the low fixed cost dilution due to the <10% ACF. We have assumed that cells will continue to be designed to capture a certain wavelength band and would not be able to capture all the light falling on them.

The levelised costs for nuclear is projected to fall from the around £89/MWh to somewhere in the £51-66/MWh under the MML assessment approach. Applying the learning rates from literature would have seen a more modest reduction on current prices. Oxera's projection of declining discount rates for nuclear would drive much of the reduction, even in low deployment scenarios.

All CCS options see little decrease, largely as the carbon price increases offset capex improvements. Gas-CCS costs stay at £100-105/MWh, while coal-CCS sees some reduction as global coal EPC markets rebalance, with prices falling to about £130/MWh. This means coal-CCS has a premium versus gas-CCS of about £27-28/MWh. This assumes that gas prices rise steadily to a plateau of 75ppt from 2030, while coal prices are fixed at £50/t (approximately 22ppt) from 2015. Gas prices would need to increase an additional 30ppt to bring gas-CCS costs up to the comparable level for coal. These CCS costs assume considerable progress in reducing the efficiency penalty of CCS, largely as the thermal losses are reduced due to advances in chemical processes. The parasitic electrical load is projected to see more modest reductions, since there will still be a significant requirement to handle large volumes of flue gas and to compress CO_2. All these CCS levelised costs include a charge for CO_2 transport and storage of £6/t CO_2.

We are not expecting any dramatic developments in any of the listed bio-energy technologies at least in terms of electricity generation. Indeed it is very possible that all these technologies will effectively be bypassed by developments in the front-end processing of biomass materials, using modern biotech processes that will yield clean biogas and/or bio-ethanol/bio-diesel (and solid marketable by-products). This is likely to happen by 2030, if not before. The products of these new biotech conversion processes may not be converted to electricity, although this would be a comparatively simple matter via established gas turbines/engines or through fuel cells. Whether this conversion happens will depend in part on the extent of additional financial incentives for biomass electricity generation compared to selling bio-methane or bio-fuels.

In the near to medium term we are projecting relatively moderate reductions in the costs of the main prime movers, AD, gas engines, combustors and boilers, steam turbines, gasifiers and pyrolysis plants. While costs could be brought down by mass production, it is unlikely that the market would be sufficient to justify substantial investment in the supply chains, not least because of issues about feedstock supply and the lack of clear winning technology that is applicable across different feedstocks.

Wave and tidal stream technologies are projected to see among the deepest reductions, especially under favourable deployment scenarios, however none of them is projected to rival offshore wind. Tidal stream is expected to continue to have an advantage versus floating wind given its higher annual capacity factor. We are projecting a levelised cost for tidal stream of £100-140/MWh, versus £200-300/MWh for floating wave. Fixed wave, with its lower capex, could see costs of £115-£140/MWh.

Technologies have more favourable cost evolution under scenarios where they are supported and higher deployment is assumed to trigger learning and supply chain upgrades. This effect feeds on itself, as improved performance and supportive environment reduce developers and lenders' risk perceptions such that the cost of capital goes down. The difference between the costs of offshore wind in the most and least favourable scenarios is almost £50/MWh by 2040. There is a similar differential between the high and low cases for nuclear in 2040. The implication of this is that the relative costs of technologies depend largely on the scenarios.

Conclusions

The analysis in this study indicates that there is considerable uncertainty in the capital costs and levelised costs of most low carbon generation technologies even for today. The uncertainty band is least for onshore wind, an established technology, however even here, site conditions and scale effects can have significant impact. For most early stage technologies, there is a huge uncertainty band to outturn capital costs, plant performance, cost of capital and hence levelised costs.

In broad terms we can say that current levelised costs of onshore wind and mini hydro and some AD biomass applications are low cost, while offshore wind, large wood fired boilers and CCS on gas and coal (based on post combustion) are in an expensive category. Solar PV, and early stage and small scale technologies (wave, tidal stream, biomass gasification, wood grate, etc) have still higher costs. Levelised costs for nuclear fall somewhere between the low cost and middle bands depending on the assumed capex and performance characteristics.

Looking forward, we are projecting that most levelised costs will fall. For the most part this represents the application of learning, although in some cases this also includes the ending of significant market congestion premiums. Solar PV is likely to see the greatest cost reductions, such that in some scenarios it will become a lower cost option than offshore wind and nuclear, though not onshore wind. The relative positions of technologies will depend on the scenario combination selected, such that it is possible to find cases where offshore wind, CCS, and nuclear are each lower cost than the other two. It is clear that pushing deployment can affect the relative costs of technologies.

While developments in the component costs and technology performance are the primary drivers of costs, financing costs, at least in terms of the discount rates applied to technologies play a very significant secondary role. What is more, when combined with deployment scenarios (and learning effects) the impacts can be substantially magnified.

It is important to remember that these levelised costs are developed on the basis of base-load plant operation (except in the case of energy constrained options [wave, wind, tidal, solar]). We have also not considered system integration impacts (such as requirement for back-up and reserve, embedded benefits, etc) or externalities both of which are outside the scope of this study. Costs have been developed on a simple economic cash flow approach, and so are not appropriate for assessing real world actual projects.

Another aspect that needs to be born in mind when consider relative costs is that technologies also have very different implications in terms of timings, due to different development and construction times and operating lives. Technologies with long lead times and operating lives, such as nuclear and tidal barrages, effectively lock in a cost for many decades, compared with shorter lead time/operating life technologies (PV and wind) offer greater optionality, which includes prospect of cost reduction.

The level of uncertainty increases as we move into the future, not just because of the usual uncertainties regarding fuel and carbon prices, and the rate of learning and supply chain upgrades, but at a more fundamental level.

As we look further into the future the importance of unknown unknowns increases. Indeed, by 2040-50 it is almost certain that some new energy producing technologies will be deployed that are not in our current list. The rate of advances in computing, biotechnology and nanotechnology is so fast that in combination this promises to bring new energy conversion, storage and production technologies. It is possible that some will have the characteristics that would allow them to be rapidly deployed, rather like mobile phones.

1. Introduction

Mott MacDonald has been commissioned by the UK's Committee on Climate Change to investigate the build up of capital and non fuel operational costs of low carbon generation technologies in order to better understand the development of levelised costs of generation to 2050. It draws upon the conclusions of work by Oxera which focused on the determination of the appropriate discount rates for the low carbon technologies.

In essence this study aims to examine the build-up of capex/opex and ultimately levelised costs of low carbon generation technologies in the UK, and their evolution over the next several decades differentiating between learning effects and exogenous drivers.

It covers over 30 technology categories including renewables, CCS on coal and gas fired plant and nuclear plants. All the technologies are considered as electricity only, although a number of the bio-energy plants might as commonly be applied in a CHP application.

The assignment tasks have included:

- Building up capital costs (current and projected to 2050)
- Developing non-fuel operational costs (fixed and variable) and estimates of key performance parameters (energy availabilities, efficiencies, etc)
- Using the above to calculate levelised cost estimates using a revised version of DECC/MML model. In building up these costs we have drawn upon DECC assumptions on fuel and carbon prices and the estimates of the cost of capital made by Oxera Consulting[3].
- Documenting the results of the analysis in a summary report.

This work has involved building from scratch a capex cost model, revising and extending the existing DECC levelised cost model (adding more than dozen new technologies) and developing an interface between the revised DECC model and our capex model. These models have been provided to CCC along with this report.

Given the wide scope of this study, the limited time frame and budget (equivalent to 60 consultant person-days) this study is necessarily at a high level. This has limited the amount of time that could be spent on each individual technology and on reviewing academic literature, etc. Even so, as we have stressed in this study there is considerable challenge examining the development of even established technologies let alone those at an early stage of deployment. It is unclear whether having had more time and budget would have narrowed the range of outcomes or increased it.

We stress that all the estimates provided in this report must be treated with considerable caution and certainly should not be used as a guide for commercial negotiations. That said our range of outcomes is necessarily narrow as we have generally considered variations from our central case rather that looking at the maximum plausible range.

[3] See "Discount rates for low carbon generation technologies" by Oxera Consulting, May 2011.

This report covers the following sections:

Chapter 2 outlines the approach to the analysis and some key high level assumptions and general findings. It also outlines the limitations of the analysis.

Chapter 3 reviews the main drivers of current and future capex and non fuel opex by main technology categories.

Chapter 4 outlines the deployment scenarios and the findings on projected costs reductions.

Chapter 5 summarises the main findings on capex by technology under the different scenarios and also comments on sensitivity tests.

Chapter 6 outlines our assumptions on fixed and variable operating costs and the cost of capital.

Chapter 7 summarise the main findings on levelised costs by technology under the different scenarios and also comments on sensitivity tests.

2. Analytical approach and main assumptions

2.1 Introduction

This chapter outlines the approach to building up capital costs and operating costs, both for current projects and for those that could be ordered anytime through to 2050.

The emphasis is on capital costs as this is the largest item for most low carbon generation technologies and fixed operations and maintenance costs tend to be closely correlated to initial capex. The chapter starts by considering current capital costs and then moves on to examine the drivers of future capital costs. It differentiates between the “learning by doing” effects and the various potential exogenous drivers that could potentially lead to marked discontinuities.

2.2 Current capital costs

As outlined in the previous Mott MacDonald report for DECC (UK Generation Cost Update – June 2010) there is little recent reliable data on actual capital costs of most generation plant. This reflects the fact that there have been very few recent transactions concluded and even when there has the information is rarely disclosed. Globally too, the level of deal activity has been low in the last 12-18 months. In both cases the notable exceptions are wind and solar PV. This has meant that in many cases costs have had to be estimated on the basis of access to data gathered from projects under development (pre-award stage) and the views of developers, OEMs, and EPC contractors.

In some cases, costs have been based on a bottom-up build-up, though in most cases we have “reverse engineered” the breakdown from overall tender quotes and headline prices on the basis of comparable component breakdowns.

The capital cost estimates in principle refer to a plant ordered in Q1:2011. In some cases, these prices are hypothetical since the technology is not yet at a stage where it could be ordered at the scale assumed as suppliers have yet to tool up and put their component supply chains in place. Where this is the case we have noted this.

We have adopted the same definition of capital costs as in the DECC analysis. This means the estimates include OEM’s and EPC contractors’ contingencies but not developers’ own contingencies. They also exclude land costs and any additional site preparation costs over and above what would be incurred on a “clean and levelled site”. They also exclude interest during construction.

The estimates also include any market “congestion premium” or discount in the case where prices deviate from level that would return a normal profit to equipment and service providers. We have sought to estimate the extent of this market price mark-up or discount based on our knowledge of recent transactions, reference to comparator technologies/ jurisdictions and discussions with the OEM and developer community. Where possible we have attempted to differentiate what components carry this premium (or discount).

In another aspect of understanding the current capex build up we have made an indicative estimate of the share of basic material costs in current EPC price by building up the costs of basic steel, copper and cement inputs.

While the component breakdowns vary hugely between technologies, it is possible to make some general comments on drivers of capital costs.

The basic raw material and energy inputs are a very small component of total capex for almost all technologies[4]. Raw material costs are typically between 2.5% and 6% of total capex (offshore wind and CCGT). The comparable share for advanced supercritical coal and nuclear are both about 4-5%. Energy consumed in construction and component fabrication is of similar magnitude.

Invariably, the largest component of the capex is the cost of labour either on-site or embodied within first tier components (and third party services). Even for a nuclear station, two thirds of the capex is accounted for by labour, supervision and project management services. Of course at one level, almost all the cost of components and services reduces to labour, once the embodied labour of all lower tier components and the capital goods required to make/deliver these is included. However, even if we take the labour input required for on-site and for the first tier component assembly, (which might typically come under an OEM/contractor control) this is likely to be the largest item for most technologies, typically more than half the input. Where the supply chain has more tiers and there are more fabricated components outside of the OEMs' control, then equipment costs can be a substantial part of the capex. It is this layering of component inputs, which can lead to large variations in capital costs, as OEMs are forced to accept scarcity premiums/ contingencies applied by suppliers along their supply chain. The variability in prices reflects profit taking along the supply chain rather than fundamental shifts in the raw material or energy inputs or in wage rates.

2.3 Future capital costs

The starting point for developing projections of future capital costs is to take the current cost estimate and strip out the market "congestion" premium. This provides an adjusted 2010/11 figure. The implicit assumption here is that all the forward equipment and service prices for power generation will be balanced, in that providers will just earn a "normal" profit. In the real world, it is very likely that some EPC markets will experience continued or renewed supply/demand bottlenecks and maybe periods of surplus. Recent experience shows that these market congestion drivers can move EPC price by the same order of magnitude as underlying costs, with supercritical coal and CCGT prices trebling and doubling respectively, in the two years to 2009. These prices have softened markedly since 2009/10 but still remain elevated by historical levels.

This recent price spike was matched by a huge decline in the number of transactions, especially for big coal steam plant and to a lesser extent CCGTs. This lack of deal volume has meant that actual excess profit realised in this period has been small. Of course, this is still a real economic phenomenon because a developer seeking to order a plant at this time, would have had to pay these prices. However, in the end, this study is concerned with long term trends and so there is a rationale for assuming that EPC markets become balanced, at least in our central case.

[4] Solar PV is the main exception, where material costs, in this case high grade silicon, can easily exceed 15% of total costs.

Once the underlying capex cost is determined, we then consider future development in two stages:

- medium term – to 2020 and;
- long term 2020-2040.

For both periods we consider a mix of learning and exogenous drivers, which allows us to build up point estimates for 2020 and 2040. We then fit a power curve through the adjusted 2010/11 figure and the 2020 and 2040 estimates, which allows us to generate annual estimates to 2050.

Central, low and high cases are developed for each technology, in principle on a component by component basis.

2.3.1 Learning effects

We have used two approaches in order to capture the fullest range of outcomes:

1. MML judgement based on what is practical over time periods (given certain deployment levels, project management processes, etc)
2. Application of experience curves using deployment scenarios and progress ratios observed in literature;

Our preferred approach to considering learning is based on combination of our own engineering judgement and insights from discussions with the industry. For each technology we estimate of the technical improvements through design modifications and also cost reductions deriving from production techniques and supply chain upgrades on up to seven component inputs. These estimates are necessarily based on judgement, however it allows the exploration of different technology development scenarios, for example, making assumptions about foundation works for offshore wind (movement to floating system), or electrical connections (replacement of AC cabling by DC cables).

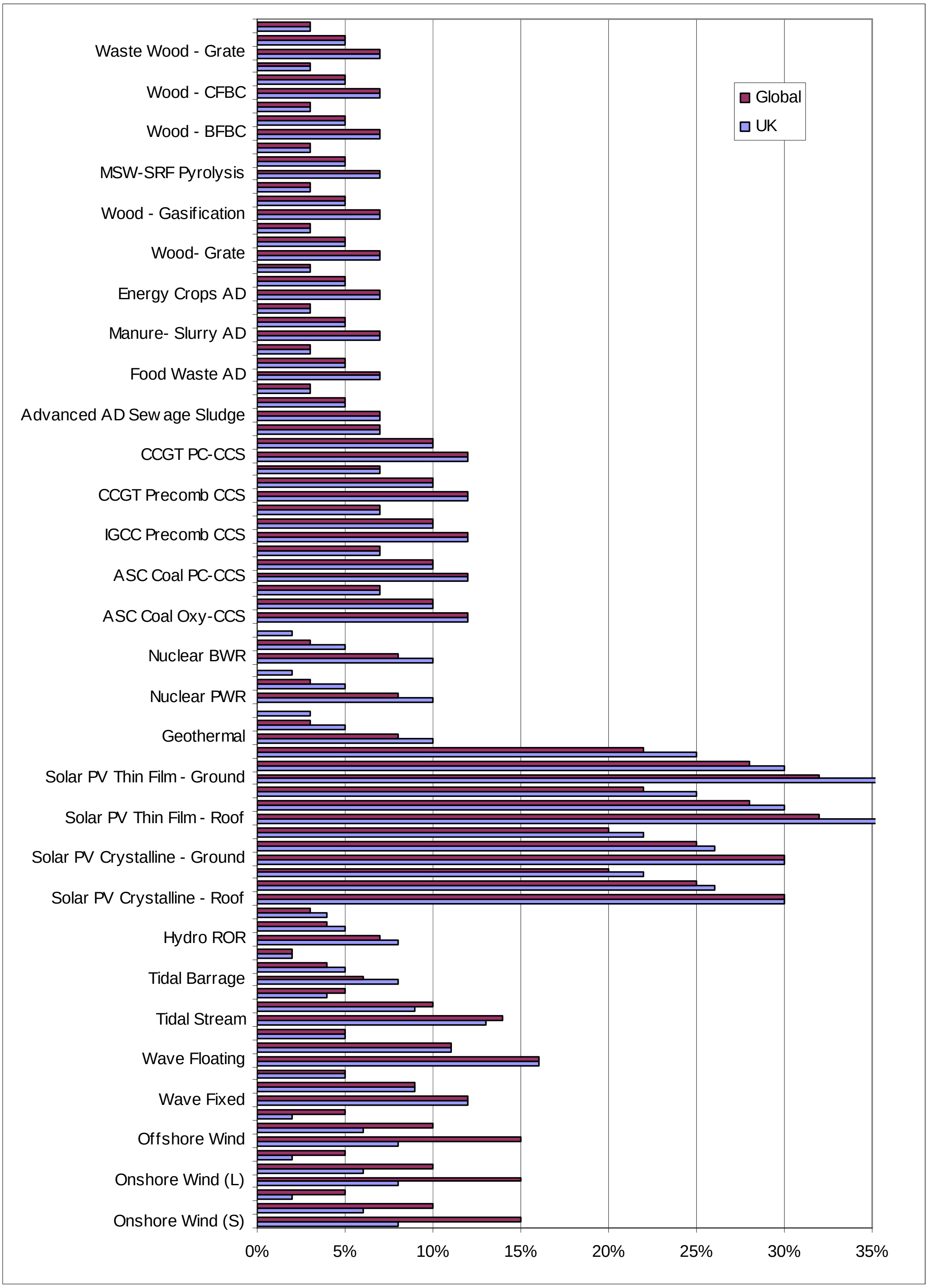
The learning curve approach has been applied as back-up and one which we can benchmark against. In recent years, several major studies have reviewed historical evidence and findings from examining learning rates applied to energy technologies, most notably the EU-funded NEEDS, the Dutch ECN and for offshore wind the UKERC ("Great Expectations") studies. All these concluded that the learning rates can be detected, however one needs to strip out short term market distortions (congestion premium, currency movements, etc). That aside, there are real challenges in applying learning rates to early stage technologies. The critical issues are the stability of progress ratios, determination of doubling levels for early stage technologies and the extent to which it is possible to apply learning rates across jurisdictions.

Most of the studies analyse the evidence across jurisdictions, generally taking a wide region, such as Europe, US, the OECD or global. The studies conclude that taking this wide jurisdiction view and multi-decade time frame, then there are generally reasonably reliable fits between cumulative deployment and capital costs for most established energy technologies. Progress ratios, which are the ratio of costs between a doubling in cumulative capacity, tend to fall in the range between unity and 0.65, with most energy technologies in the 0.95-0.85 band. This implies a learning rate of 0% to 35% per doubling, with most in the 5-15% range.

Solar PV has the highest learning rates with 25-35%, while nuclear has recorded the lowest, in some studies even showing significant negative learning. The nuclear results are generally explained by the history of ever more intrusive and demanding regulatory requirements. Many in the nuclear industry point out that in some jurisdictions, where the regulatory environment has been more stable and the industry has achieved a reasonable level of series production, the costs have fallen, most notably in South Korea.

This study applies a range of learning rates for each technology and these are shown in Figure 2.1. The projected doubling ratios are generated from a set deployment scenarios which are discussed further in Chapter 4. The chart three paired values for global and UK learning rates for a low, medium and high cases for each technology.

Figure 2.1: Learning rates by technology



Source: Mott MacDonald estimates based on literature review

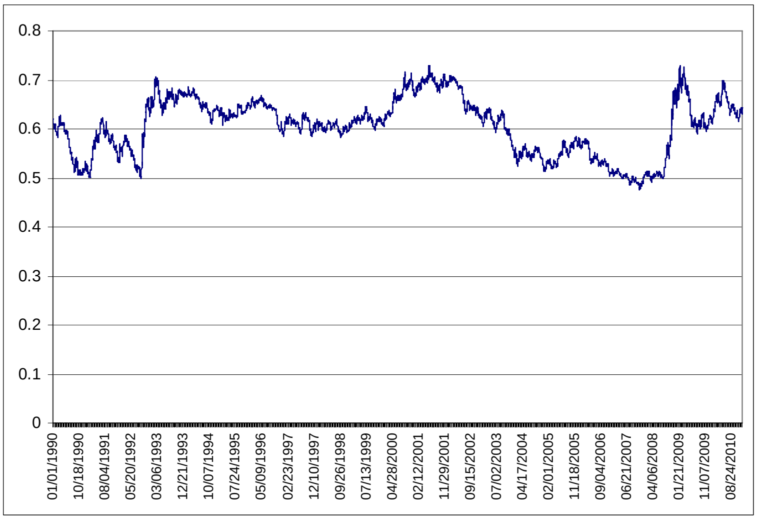
2.3.2 Exogenous drivers

There are a number of exogenous drivers that can influence power plant capital costs. We have already mentioned the impacts of market conditions through the impact of congestion premiums (and potentially discounts) on prices. We now consider five other exogenous drivers:

- Exchange rates;
- Raw material costs;
- Business and regulatory context;
- Effects of competition from low cost jurisdictions;
- Major technology/scientific breakthroughs.

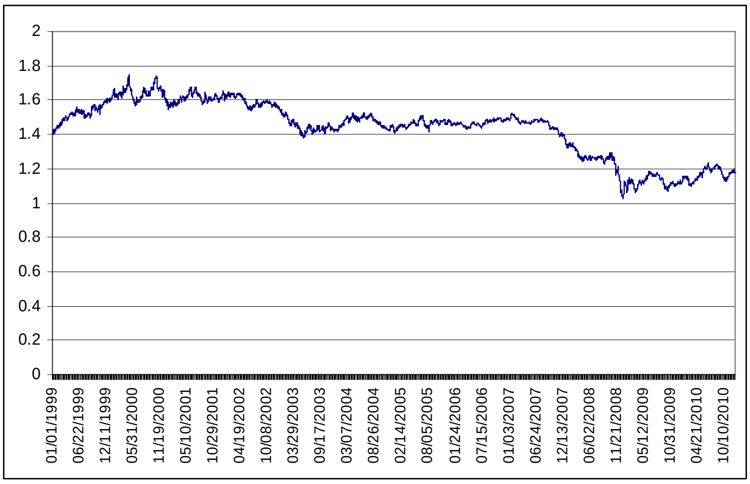
Movements in exchange rates can have a considerable impact on capex prices in the short term, as has been seen in the WTG and GT markets in recent years (where the former is priced in Euros the latter in US dollars). However, over a longer cycle these effects balance out. There is a question as to whether the current capex prices should be adjusted for "distorted" current exchange rates. In practice, though it is difficult to be confident of the direction of movement; exchange rates are not "mean reverting" in the same way that raw material costs and equipment costs are. Observation of the long run trends of sterling versus the US dollar and Euro show that current levels are not far from the long run averages. For all these reasons, we have decided to assume that current exchange rates remain fixed through the period.

Figure 2.2: US dollar – Sterling exchange rate since 1990



Source: Oanda

Figure 2.3: Sterling – Euro rates since 1999

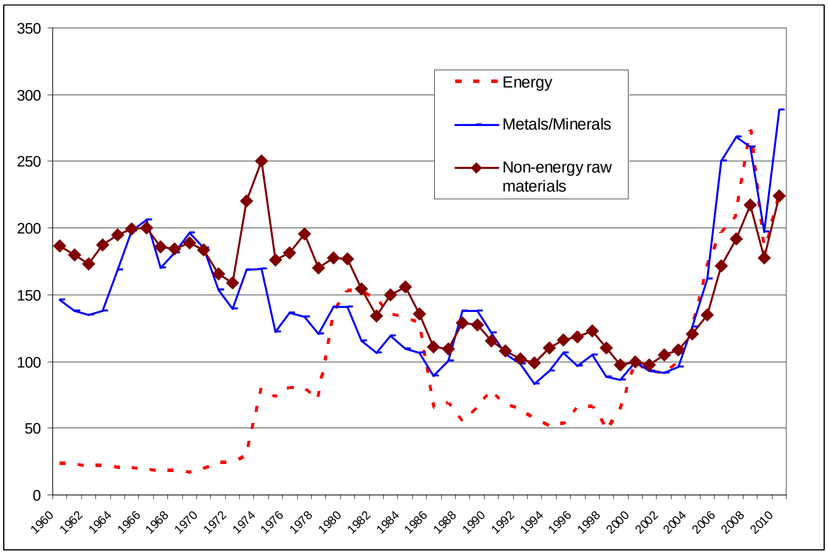


Source: Oanda

Raw material prices are another item that is often seen as key driver of capital costs. Our analysis indicates that the direct linkage is in fact extremely weak as the basic raw materials even at the peak of the market typically accounted for less than 5% of capital cost.

Raw material prices are generally at a high level by long term historical levels as is illustrated in Figure 2-4. There is some disagreement among economists as to whether prices will continue to increase (under the burden of strong demand growth lead by Asian giants and depleting resources) or whether it will return as supply side responds by finding better ways to extract existing materials and find substitutes. It is indeed the case that the long run marginal cost of bringing on new capacity for most raw material commodities is less than current prices. Given these uncertainties, we have assumed that material prices remain fixed in real terms through all our scenarios.

Figure 2-4: Commodity prices over last 50 years in real terms



Source: World Bank

The business and regulatory environment is likely to be a key player in affecting costs, though this will normally be felt through the impacts on deployment of technology and hence the scope for learning by doing and through discount rate risk premiums. However, as mentioned earlier (in the case of nuclear) it is possible to have strong deployment accompanied by tightening compliance requirements that act to partly or wholly offset the effects of learning. This could continue to be the case for nuclear, though this is not our central case view. The same might apply for CCS based on concerns relating to potential releases of CO_2 and there will be other examples. On the other hand, there may also be cases where the business and regulatory climate actually accelerates learning through providing support to R&D initiatives and increasing the demand "pull". The US Federal Government's recent announcement of the "Sunshot" programme, that aims to bring solar PV costs to $1000/kW by 2020 is such an example.

While these business and regulatory effects offer the potential to constrain or accelerate developments they are difficult to separately quantity so we have not explicitly treated them in this analysis, except through their impact on deployment. They are however embodied to some degree in our engineering based estimates of the learning effects.

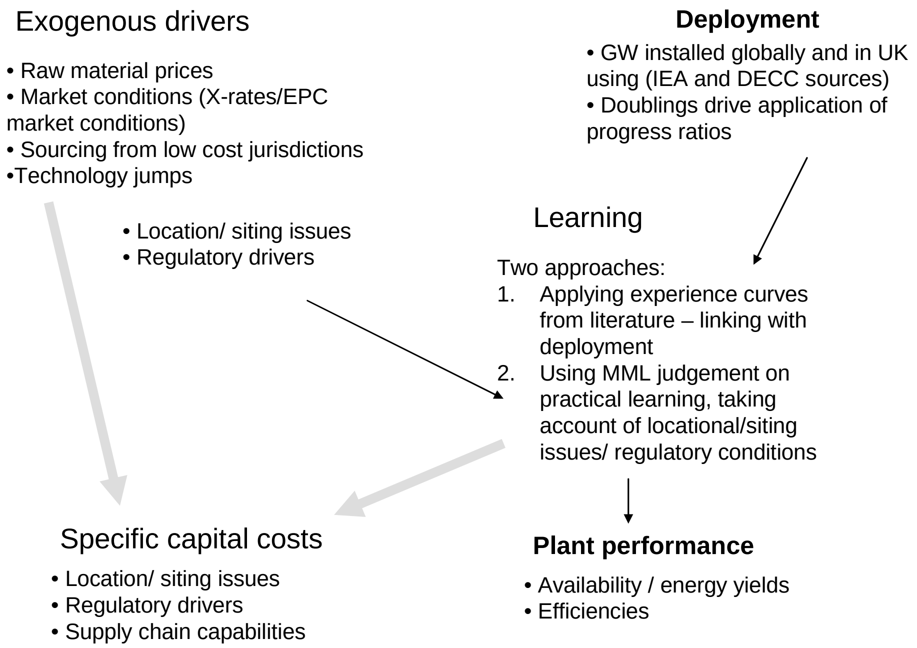
It is mentioned above that the supply chain and production improvements are included as one half of the learning effect. However, this excludes the potential step changes in costs arising from competition from low cost jurisdictions, the so-called "China affect" although it may be other jurisdictions too. This China effect was clearly demonstrated in the FGD market, prices for which had stabilised around $150/kW, when after a few years of production, the Chinese had brought prices down to $75/kW for product delivered in China. The main issue here is the extent to which the costs in low cost jurisdictions can be transferred into costs/prices in the equipment markets relevant to the UK. To some extent this is already happening on an incremental basis as a significant amount of component supplies of "Western" supplied big coal plant is already sourced from China or other low cost suppliers, though often branded as a product of major western OEM or balance of plant supplier. A number of major Chinese and other low cost manufacturers have aspirations to offer equipment under their own brands, though of course they will need to meet European and North American certification standards. Chinese and Indian WTG manufacturers are already supplying into the European market. In the longer run, it is quite possible that the Chinese and other suppliers may offer the "state-of-the-art" equipment, most likely first in CCS and PV, but eventually in nuclear technologies.

It is unclear what the savings will be from accessing lower cost production facilities, however it is unlikely to lead to more than a 10% reduction on the learning trend line. For most technologies we have allowed for about a 5% reduction that could be applied both by 2020 and by 2040, making a saving of roughly 10% over the next 30 years. However, in none of three archetypal scenarios is this exogenous driver applied.

A common criticism of learning curves is that they do not take account of major breakthroughs in technology which can be seen as discontinuities. This is probably a fair criticism for the really major jumps, though of course the learning process comprises many discrete jumps when viewed close up. The challenge is to separate out the big breakthroughs. For offshore wind, it is unclear whether a move to floating foundations would represent such a major discontinuity, especially if the floating system was almost as expensive as the seabed mounted structures (as was initially the case for offshore oil exploration rigs).

Even so, we have again provided the facility to allow step changes in costs as a result of an exogenous technological breakthrough. As with the low cost jurisdiction impact we constrained this to about 5% in each time block (to 2020 and 2040) in our central case; although again, all three of the archetypal scenarios do not apply this.

Figure 2-5: Schematic of main determinants of future capital costs



Source: Mott MacDonald

2.4 Unknown unknowns

It is almost certain that some new energy producing technologies will be deployed by 2040-50 that are not in our current list. The rate of advances in computing, biotechnology and nanotechnology is so fast that in combination this promises to bring new energy conversion, storage and production technologies. It is possible that some will have the characteristics that would allow them to be rapidly deployed, rather like mobile phones.

It is not the remit of this study to explore this area of possibility, although we have commented at the end of section 3 on a few technologies that have been demonstrated at the lab scale which could indicate the kinds of things in prospect. However their inclusion here moves them into the known unknowns.

3. Main drivers of costs by technology

3.1 Introduction

This chapter provides a high level review of the main low carbon electricity generation technologies that are being considered for deployment in the UK. It focuses on the drivers of costs particularly capital costs, both for current plant and possible future plant.

It is structured with the renewable generation first, taking the major potential contributors first, and then follows by considering nuclear and carbon capture and storage on coal and gas fired plant. It finishes with a few comments on potential new technologies.

3.2 Wind

3.2.1 Onshore

3.2.1.1 Current costs

On-shore wind is a mature renewable technology, which appears to have converged on a horizontal axis (generally three blade) machine. The basic equipment varies little between sites and scales, with steel tubular towers being the predominant support for wind turbine generators (WTG) above 1MW.

Costs have risen slightly in recent years, but have softened recently such that there is thought to be little “congestion” premium in the market, in contrast to the offshore market which remains overheated. There is now considerable competition in the equipment market, with a large number of manufacturers including Chinese and Indian companies (although these have yet to make in-roads into Britain).

Table 3.1: Assumed configuration for onshore wind-farms

	WTG rating: MW	No. of WTG	Total installed capacity: MW
Small WTG	0.8	20	16
Large WTG	2	8	16

Source: Mott MacDonald

Current costs are estimated to range between £1300 and £1500/kW, depending on scale, with our central figure of £1350/kW and £1450 for large and small unit wind-farms, respectively. A very small market congestion premium of 2.5-3% is included in these estimates. The wind turbine generator is by far the largest item, accounting for about 65% of the specific capex. Civil works and electrical connections are much smaller elements than offshore, accounting for 13-14% and 7% respectively. Material costs are estimated to be a trivial 2.5% of total costs. Table 3.2 shows the indicative breakdown of capital costs for a windfarm of total capacity of 16MW based on 2MW (8 units) and 0.8MW (20 units) WTGs, hereafter called large and small onshore wind.

Turbine sizes have stabilised at 2-3MW for the larger high wind sites and 0.75-1.0MW for more constrained sites. Typical annual capacity factors (ACF) (on a net energy basis) for new windfarms being developed today are 23-30%, depending on site conditions and the WTGs’ energy harvesting performance. Higher ACF are achievable, especially using the higher yield machines, however, the better sites have already been taken. Clearly, there is some scope for re-powering, but the costings here are based on new windfarms.

Fixed operating costs for wind are low, at just 1% of EPC costs, while variable operating cost is zero.

Table 3.2: Current capital cost breakdown for onshore wind

	Large WTG windfarm		Small WTG windfarm	
Cost component	Base price: £/kW	% share	Base price: £/kW	% share
Development	100	7%	120	8%
Turbine	870	64%	900	62%
Foundation	170	13%	210	14%
Electrical	100	7%	100	7%
Insurance	40	3%	40	3%
Contingencies	70	5%	80	6%
Total	1350	100%	1450	100%

Source: Mott MacDonald

3.2.1.2 Future developments

Looking to the future, there is a general consensus that there is no dramatic change on the horizon. The technology is mature and the market is reasonably balanced. There is a chance that the lower cost suppliers from China and India may seek to win a larger share of the European market, assuming that they have spare capacity. MML central case projects real cost reductions of 10-15% over the next decade and 20-25% by 2040 versus the 2011 level. This takes total capex costs down to just below £1200/kW in 2020 and below £1050/kW by 2040 for the large schemes.

These reductions are likely to be driven by falling WTG costs, with foundation, electrical and other items subject to more modest reductions. But even in 2040, the WTG is projected to account for 55-60% of the total capex. Table 3.3 and Table 3.4 show the projected costs for the large and small windfarms respectively, under the MML central case.

The learning curve literature indicates cost reduction rates of around 10%, which would imply that cost reductions of 20-30% may be expected by 2040 depending on future deployment levels. This is broadly consistent with our engineering assessments.

Table 3.3: Projected capital costs in £/kW for a large onshore WTG windfarm in 2020 and 2040 under MML central case

	2011	2020	2040	% of 2011 costs in 2020	% of 2011 costs in 2040
Development	100	98	93	98%	93%
Turbine	870	737	630	85%	72%
Foundation	170	159	144	93%	84%
Electrical	100	91	83	91%	83%
Insurance	40	37	34	93%	84%
Contingencies	70	65	59	93%	84%
Total	1350	1187	1042	88%	77%

Source: Mott MacDonald

Table 3.4: Projected capital costs in £/kW for a small onshore WTG windfarm in 2020 and 2040 under MML central case

	2011	2020	2040	% of 2011 costs in 2020	% of 2011 costs in 2040
Development	120	118	112	98%	93%
Turbine	900	762	652	85%	72%
Foundation	210	196	177	93%	84%
Electrical	100	91	83	91%	83%
Insurance	40	37	34	93%	84%
Contingencies	80	74	67	93%	84%
Total	1450	1279	1124	88%	78%

Source: Mott MacDonald

On the basis of this forward capital cost assessment the levelised costs of generation from onshore wind is projected to fall from about £83-93/MWh to £63-72/MWh and £51-61/MWh in 2020 and 2040, on the basis of Oxera's central discount rate projection[5].

3.2.2 Off-shore

3.2.2.1 Current costs

Offshore wind is at an early stage of deployment, with only a decade since the first commercial installation in Denmark. For UK everything started with Round 1 demonstration projects quite close to shore (less than 10km) in shallow waters (less than 15 metres) and with a total capacity between 60 and 90MW. The developers at that time were ambitious midsized companies. The largest offshore wind turbine was 3 MW. Round 2 projects that are currently under construction have capacity between 150MW and 500MW in water depths up to 30 metres. The largest turbine available today is 6MW, the furthest offshore project in UK under construction is 30km. Today the developers are mainly large utilities. Round 3 (R3) projects that are expected to start construction in 2015 will have a size of more than 1 GW in water depths between 30 and 60 metres and with distances to shore of can be in excess of 50km. New turbine manufacturers will enter the market with turbine sizes between 5 and 10 MW. Today the UK has 1,341 MW of offshore wind that is expected to expand to more than 5 GW by 2015 and may reach more than 25 GW by 2020.

Thus, the trend of the market is quite clear and challenging: Going for deeper waters, further offshore, using larger machines and bigger vessels and building many large wind farms. Approximately 1GW per year till 2015 and possibly 4GW per year after 2015, considering solely the UK. As this market continues to be developed in challenging locations and being innovative, there has been comparatively limited scope for learning as yet. Indeed, the evidence is that costs actually increased during the last five years as the industry found the offshore environment more challenging than they had expected and as equipment and service markets became overheated. This lead to the layering of contingency premiums, which pushed up quoted EPC[6] prices. This process is well documented in the "Great Expectations" report from UKERC.

[5] Oxera's central discount projection for onshore wind falls from 8.5% currently to 7.0% in 2020 and 6.4% in 2040.

[6] EPC here means engineering, procurement and construction prices as quoted by the combined suppliers rather than necessarily an EPC contractor's fully wrapped price.

Our estimate of current costs for an early stage R3 scheme is around £3000/kW. This is based on a wind farm of 25 WTG rated at 5MW each in 20 metres of water and 30 km offshore. This assumes a steel jacket support structure. The WTG is the largest component at 45% (much less than for onshore), while the foundations and electrical connection account for about 25% and 20%, respectively. Insurance and suppliers' (or developers) contingencies accounts for another 2% and 7% respectively.

These costs relate to a near "state of the art" scheme. There are lower cost schemes being developed today based on smaller WTGs (rated at 3-3.6MW) and monopole foundations, which would have a significantly lower capital cost at about £2600/kW for the same capacity. These tend to have a lower energy yield than the latest generation and larger machines and monopile foundations are restricted to water depths up to 30 metres using turbines smaller than 5MW.

While capex costs are much higher than for onshore, the annual capacity factors are considerably higher too, with 35% (net) now typical. Fixed operating costs are also much higher than for onshore – because of the need to employ marine services and/or have staff posted offshore. Fixed operations and maintenance costs typically work out at about 2.5% of EPC costs.

Table 3.5: Cost build up for current early stage R3 offshore wind

	Component cost £:	Cost (£) per MW	% of total
Development	442,000	88	3
WTG	6,911,000	1382	45
Foundations	3,645,000	729	24
Electricals	3,018,000	604	20
Insurance	331,000	66	2
Contingency	1,091,000	218	7
Total	15,438,000	3088	100

Source: Mott MacDonald

Bringing all this together indicates an overall levelised cost of £140-180/MWh, depending on the wind yield and discount rates applied.

3.2.2.2 Future developments

Our own assessment is that the current market overheating has elevated the capex costs by about 15% for projects being considered today. Unlike in the conventional thermal power sector, where there is the expectation of a rebalancing, there is some uncertainty as to whether the offshore sector will rebalance before 2020. This is because demand growth is so strong and as yet there are still comparatively few players in the large WTG market.

Stripping out this "market congestion" premium there is clearly scope for significant cost reductions for a given wind regime and wind farm location. Of course, as deployment increases in any jurisdiction, there is typically a movement to more challenging sites. This is happening in the UK as R3 sites replace R2 and as we move to the harder locations within R3 and then beyond. This move into deeper water and further offshore will, other things being equal, increase the costs of foundations, installation and grid connection.

But we can expect significant cost reductions on a number of fronts:

- Moving to larger WTG and windfarms brings a number of economies of scale (expressed in £/kW) and sharing of infrastructures;
- upgraded supply chains (economies of scale, service innovations[service hotels], etc);
- Competition from suppliers from China (and other lower cost jurisdictions);
- Move to HVDC connections (reduces cable costs through reducing number of cables);
- Improvements and even breakthroughs in foundation design (latter coming from floating systems [often taken from oil and gas sector experience]);
- Lower mass generators (based on high temperature superconductors); and
- Novel WTG designs (such as new vertical axis machines [Nova]) that offer higher capacities and lower cost foundations.

The above drivers should become increasingly important through the coming decade, such that underlying costs begin to fall sometime after 2015. Our view based on an engineering cost build up is that the capital costs could fall by 28% per MW by 2020 and 43% per MW by 2040. This is based on moving into successively deeper water and further distance, while at the same time increasing the WTG size and total wind-farm capacity. It also assumes that foundation technology remains based on steel jacket structures, but there is a shift to HVDC power connections. We also assume that the equipment and service market moves into balance such that there are no congestion premiums from 2020 onwards. Table 3.6 shows our assumptions while Table 3.7 shows the projected capital cost build up for 2020 and 2040.

Table 3.6: Capacity, water depth and distance assumptions for offshore wind

Scenarios	2010	2020	2040
WTG type (MW)	5	10	20
Number of units	25	100	200
Water depth (m)	20	40	60
Distance to shore: km	30	60	100

Source: Mott MacDonald

All the main components in offshore costs are projected to see significant reductions, however the electrical and WTG costs are expected to fall most almost halving between 2011 and 2040.

While we have assumed some fairly major advances in WTG moving eventually to 20MW machines, we have not assumed a shift to floating foundations, which could potentially bring further cost reductions. Our view is that a reasonable optimistic case would include deeper cost reductions based on floating foundations and new vertical axis machines. Further downward cost pressure could also come from the efforts of more vigorous competition from China and other low cost jurisdictions. It is conceivable that by the 2020s a fleet of dedicated WTG carriers could be bringing a large proportion of Europe’s offshore wind equipment from Asian and other low cost suppliers.

Technical improvements are likely continue such that wind yields are likely to increase through to 2020 and then more slowly beyond this. Of course, actual wind yields will depend on the wind regime, however it is expected that annual net capacity factors of 40% will be typical by around 2020 with 45% by 2040. Expressed in capital costs per MWh generated these improvements combined with the capital cost reductions indicate a fall in capital cost per MWh (excluding discount rate impacts) of 55% by 2040, versus current 2011 prices.

Operating costs should fall at least in line with capex costs, assuming a continued build up of the service industry, particularly as more staff and services are expected to be located offshore (as deployed capacity increases).

Table 3.7: Projected capital costs for offshore wind in £/kW

	2010/11	2020	2040	% of 2011 costs in 2020	% of 2011 costs in 2040
Development	88	62	56	70%	63%
Turbine	1382	999	758	72%	55%
Foundation	729	562	447	77%	61%
Electrical	604	388	310	64%	51%
Insurance	66	51	44	77%	66%
Contingencies	218	175	150	80%	69%
Total	3088	2237	1764	72%	57%

Source: Mott MacDonald

The above cost projections are clearly one view of the outlook to which we would add a subjective band of plus or minus 20% by 2040. The uncertainties are largely associated with the extent to which the economies of scale in WTGs and windfarms are captured and the extent to which larger capacity base allows production and installation cost savings. Technological advances are expected to play a secondary role, except where this allows larger capacities to be deployed. Market congestion arising from bottlenecks in supply chains could potentially continue to distort prices, however in the long run, the lessons from economics is that the supply side will respond.

Taking the above capital cost assessments and Oxera's central discount rate case (outlined in Chapter 6) gives an indicative current levelised cost of £169/MWh. This includes the market congestion premium on the capex. Using the MML assessment approach and looking forward, and again taking the high and low case projections for capex, while keeping other inputs and discount rates at the central case in Oxera's assessment (Table 6.7[7]) gives a levelised cost in 2020 and 2040 of £103-114/MWh and £69-82/MWh, respectively. The comparable figures using the learning curve approach are £85-95/MWh and £60-75/MWh. This is only considering capex uncertainty and this excludes the effects of technological breakthroughs and out-sourcing to low cost jurisdictions. There is clearly large band of uncertainty around these projections and these uncertainties are explored further in Chapter 7, which summarises the findings on levelised costs,

3.3 Solar Photovoltaic (PV)

An introduction is given to solar Photovoltaic (PV) technology and how it would most likely be deployed in the UK. For the purposes of economic modelling, four representative PV applications are described and the key assumptions used to make cost projections to 2040 are then described.

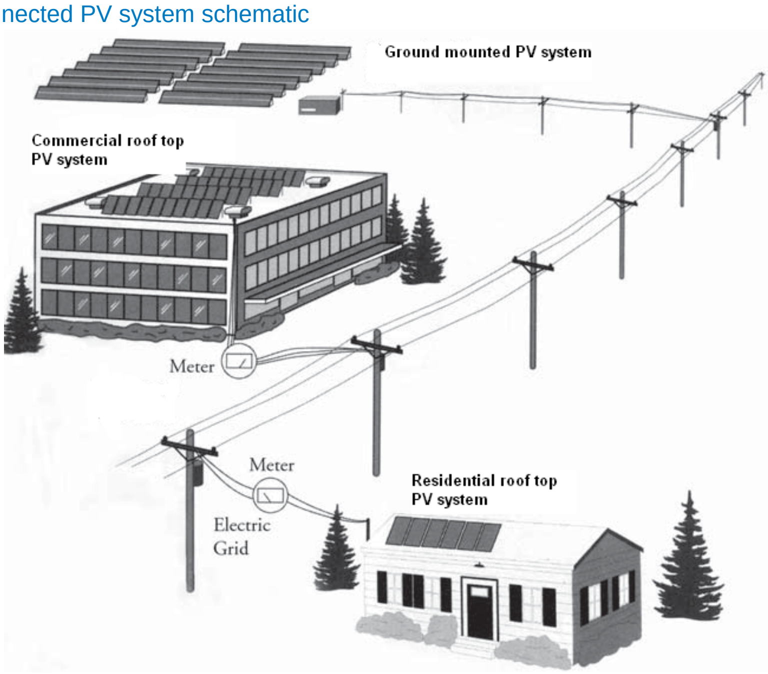
Key sources of information have included public domain web-based sources, academic papers and Mott MacDonald's knowledge of PV primarily acquired through our technical advisory role in around 3000 MW of PV projects worldwide.

[7] This shows discount rates for offhshore wind falling from a current 12% to 10.5% in 2020 and 8.3% in 2040.

3.3.1 Introduction

Simply put, Photovoltaic (PV) technology is a means of converting energy from sunlight directly into electricity. The basic building block of a PV system is the solar cell and without delving too deeply into the physics, it is sufficient to understand that the solar cell is made from a specific material called a 'semiconductor' which generates a small electrical charge when subjected to sunlight; this is known as the 'photovoltaic effect'. A number of solar cells are arranged together on a solar module, which is installed on the roofs of houses or in large ground mounted installations (shown in Figure 3-1).

Figure 3-1: Grid connected PV system schematic



Source: RETScreen - Photovoltaic Project Analysis, adapted from Ross and Royer, 1999

Solar modules generate Direct Current (DC) electricity, which needs to be converted into Alternating Current (AC) before it can be fed into the electricity grid and used in our homes and businesses[8]. The device used to convert DC to AC is called an inverter and thus the two key components of PV generation are both the modules and the inverter.

The UK is a small player in the international PV market and so it is not possible to look at price trends in the UK without looking at the broader global context. Since around 2005 the global market in PV generation has been expanding exponentially (as shown in Figure 3.2) and this has mainly been as a result in renewable energy incentive programmes. Increased markets for PV technologies has led to investments that have improved the supply chain, led to technological advancements and created economies of scale that have caused significant decreases in the installed cost of PV. For example, prices for installed Photovoltaic systems were reported to have declined 30% between 1998 and 2008 according to a study by Lawrence Berkerley National Laboratory (2009), which covered 16,000 PV installations in the US. The downward trend in prices is predicted to continue.

[8] It is possible to store the electricity in batteries rather than exporting it to the grid but this is only likely to be the case in a small number of 'island generation' cases. For the purposes of this economic review we are considering only grid-connected PV systems.