

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.

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[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).

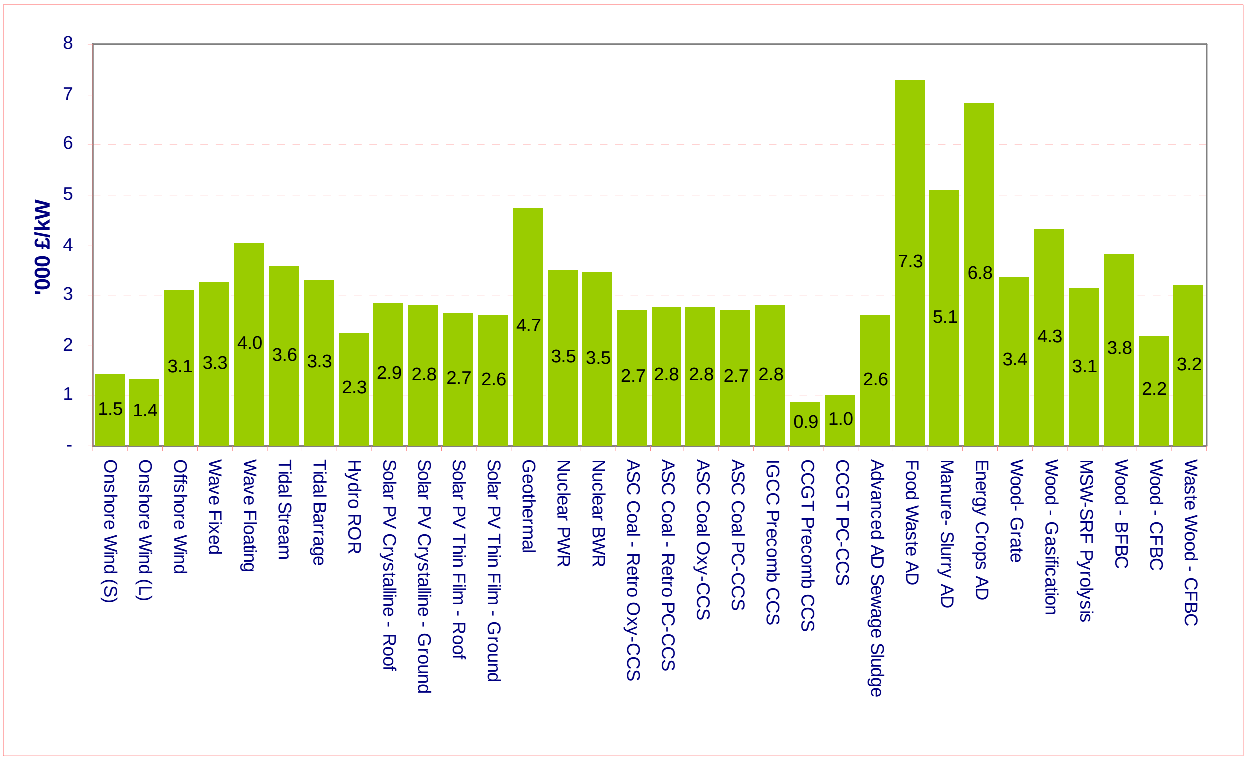
The prime mover[2] is typically the largest item for renewable technologies, however its share varies considerably depending on the extent of civil support/containment structures and feedstock treatment (for biomass). For instance, for onshore and offshore wind the wind turbine generator accounts for 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.

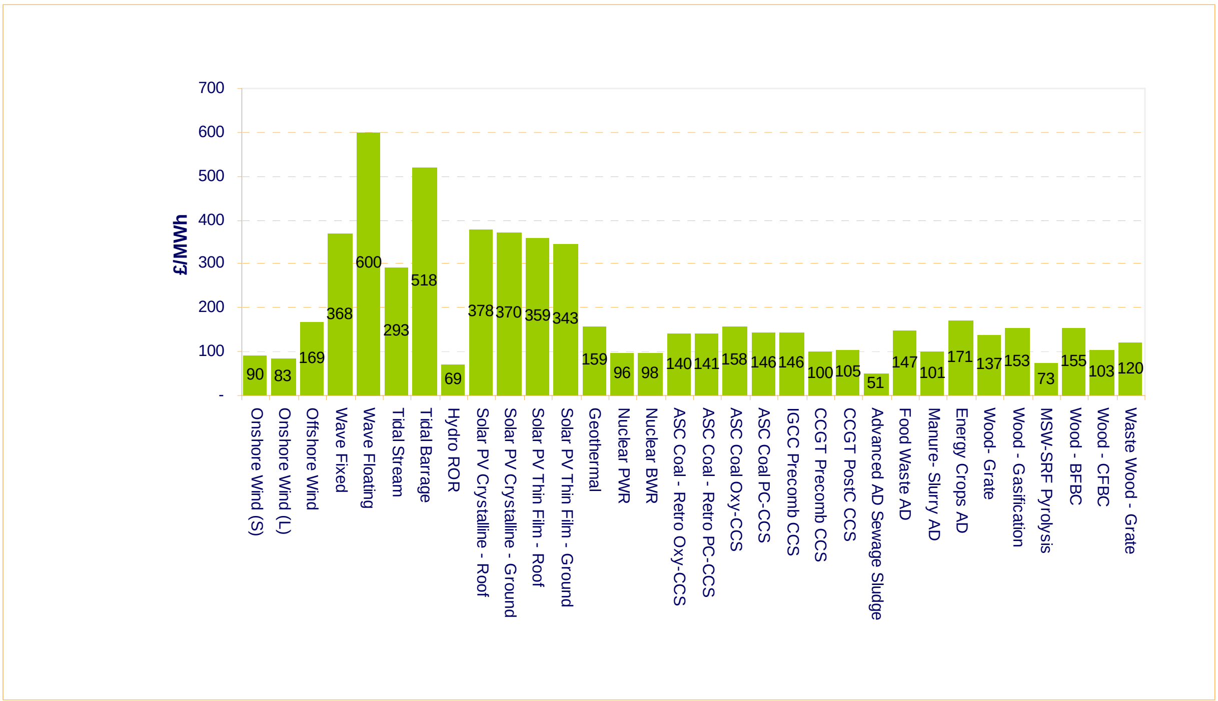
Of the other low carbon technologies now being considered for wide deployment, solar PV is quite clearly very expensive at £343-378/MWh. This reflects the early stage of this technology and the low annual capacity factors (~10%) achievable in a UK setting.

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.

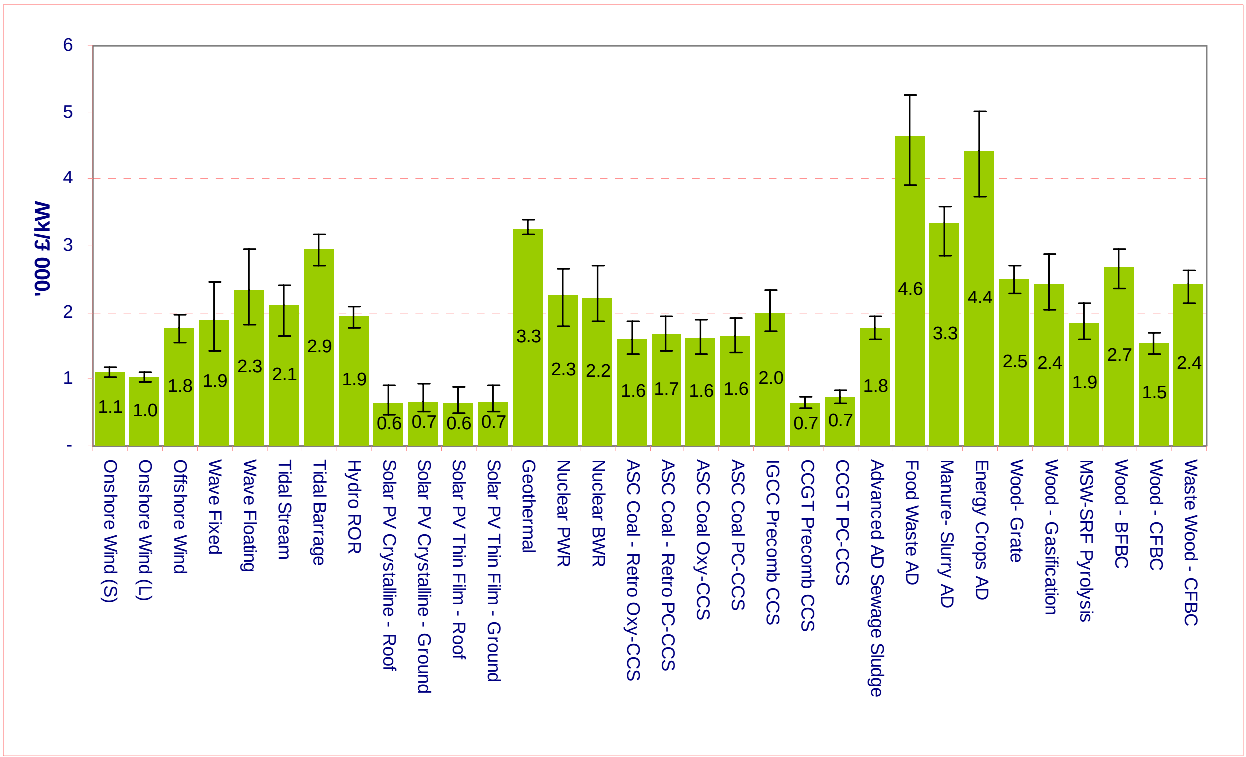
- The extent of market congestion will clearly depend on the balance of supply and demand in each market segment. We have taken the view that the market will rebalance in the long term. In practice, there may be periods of scarcity and surplus which would drive a large wedge between prices and underlying 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



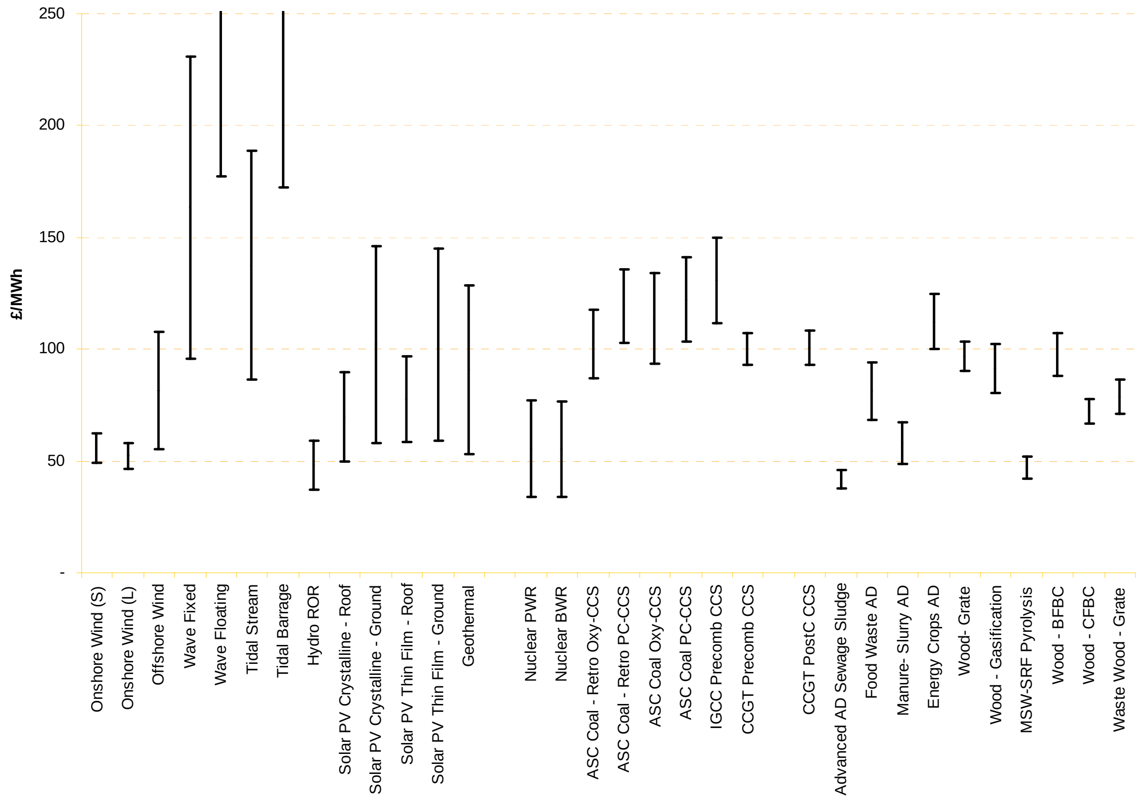
Source: Mott MacDonald

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).

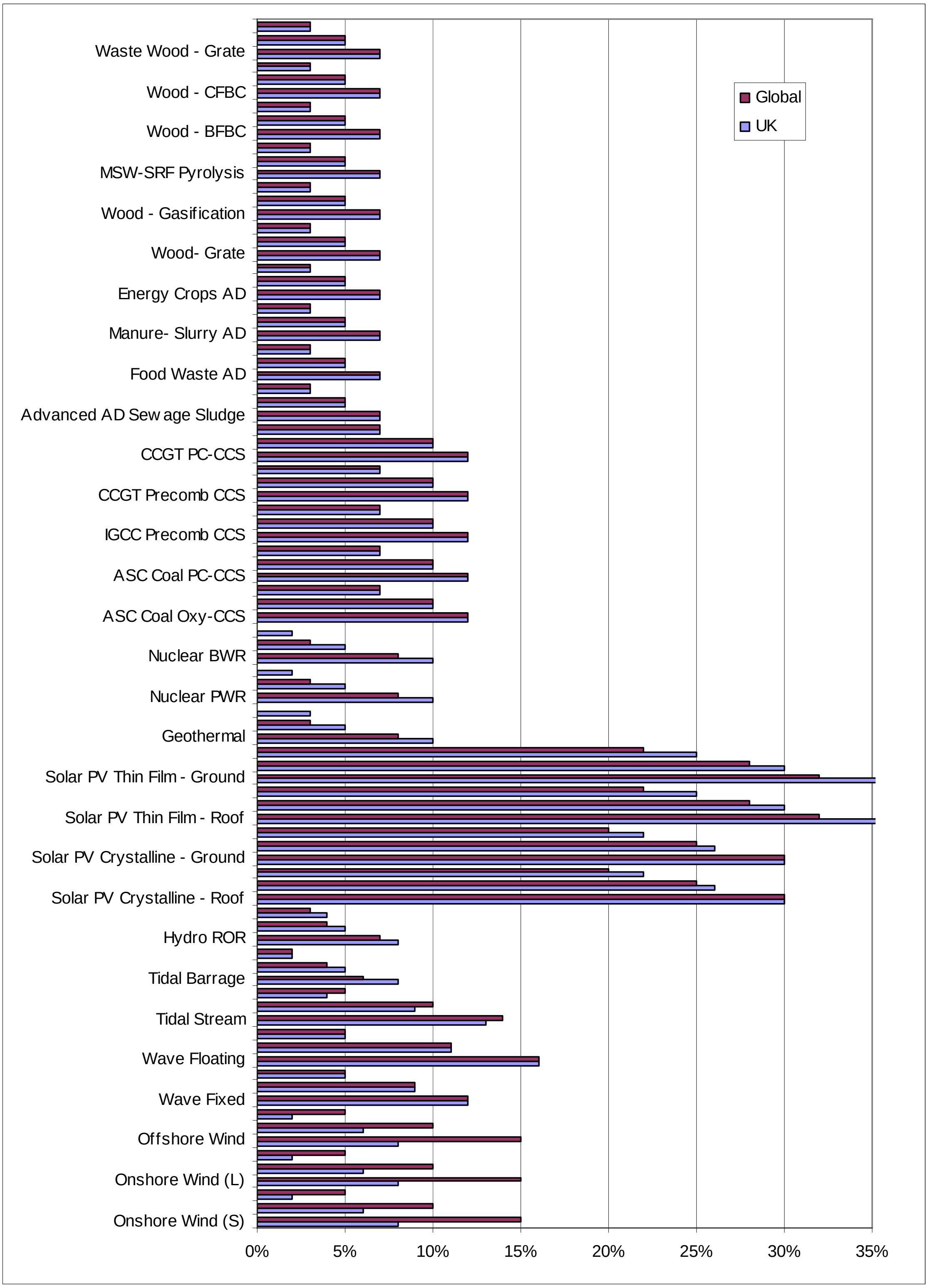
The learning curve approach has been applied as back-up and one which we can benchmark against. In recent years, several major studies have reviewed historical evidence and findings from examining learning rates applied to energy technologies, most notably the EU-funded NEEDS, the Dutch ECN and for offshore 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

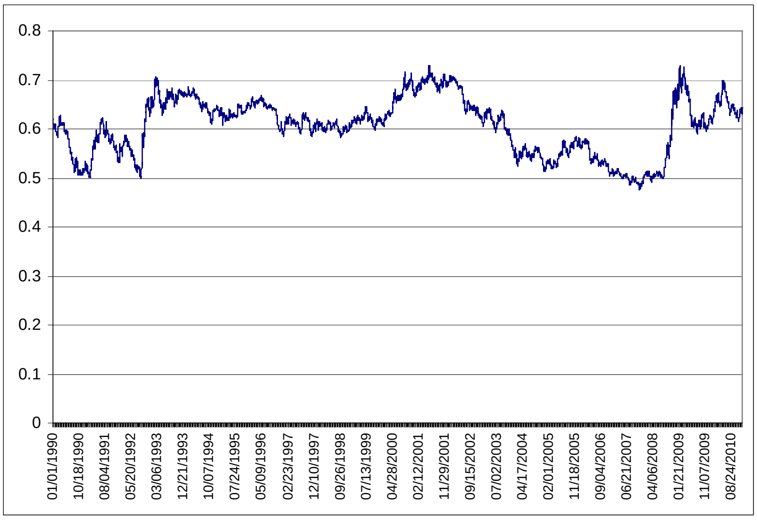
2.3.2 Exogenous drivers

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.

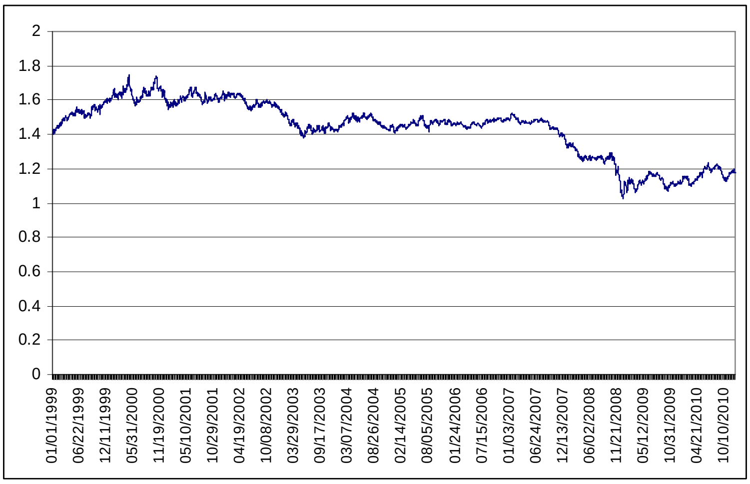
Movements in exchange rates can have a considerable impact on capex prices in the short term, as has been seen in the WTG and GT markets in recent years (where the former is priced in Euros the latter in US dollars). However, over a longer cycle these effects balance out. There is a question as to whether 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

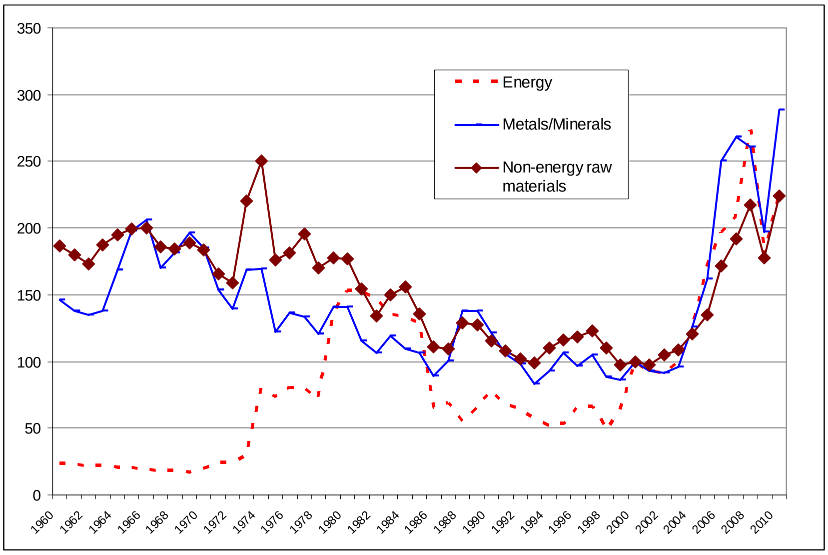


Source: Oanda

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.

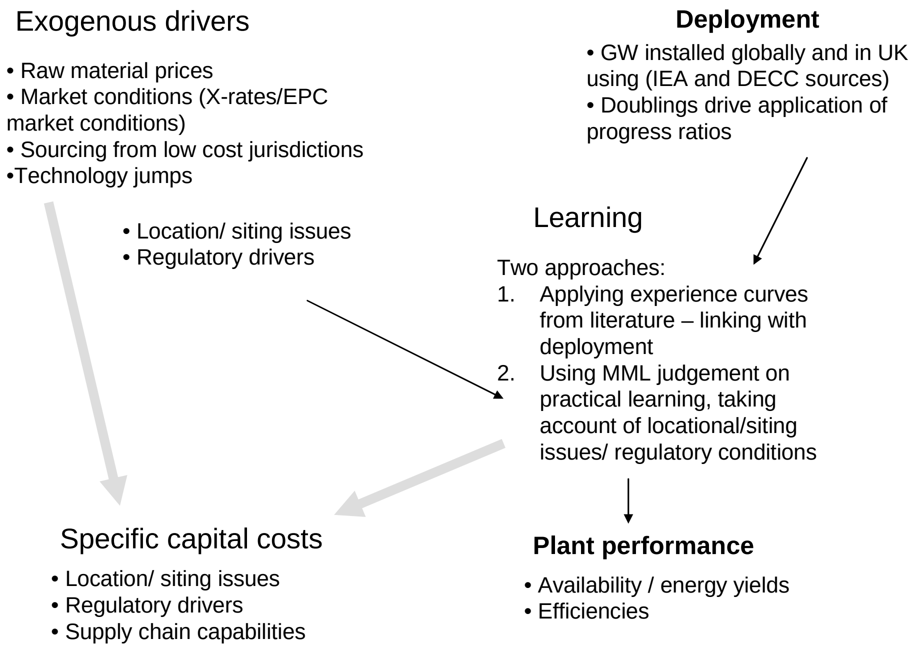
It is mentioned above that the supply chain and production improvements are included as one half of the learning effect. However, this excludes the potential step changes in costs arising from competition from low cost jurisdictions, the so-called “China affect” although it may be other jurisdictions 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.

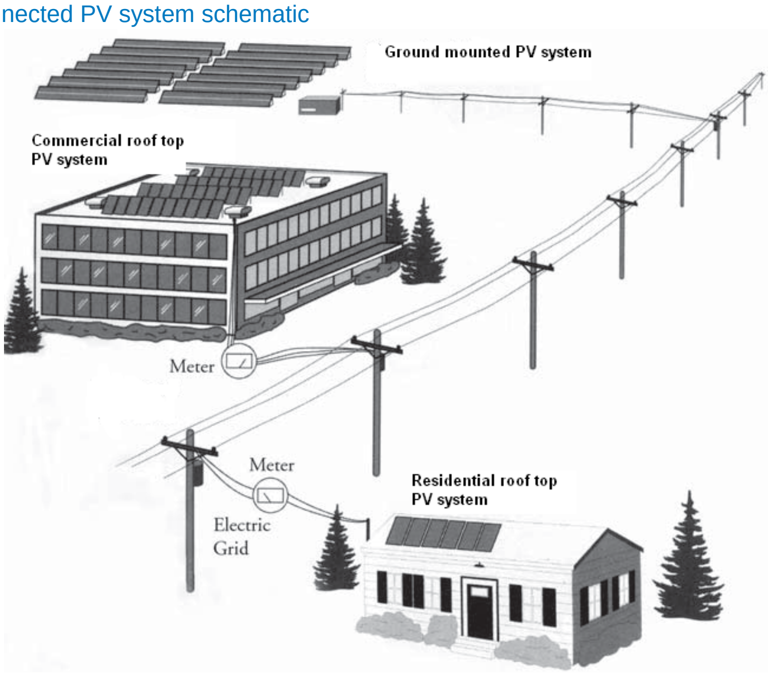
Key sources of information have included public domain web-based sources, academic papers and Mott MacDonald's knowledge of PV primarily acquired through our technical advisory role in around 3000 MW of PV projects worldwide.

[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



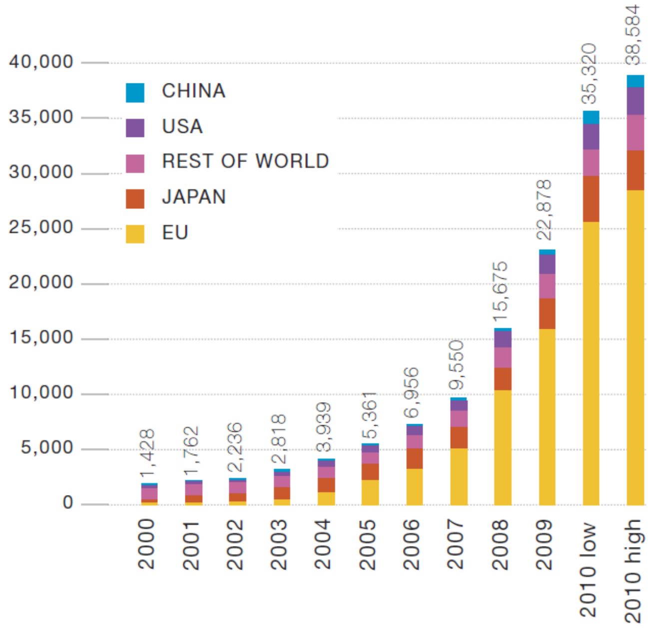
Source: RETScreen - Photovoltaic Project Analysis, adapted from Ross and Royer, 1999

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.

Figure 3.2: Global PV installed Capacity

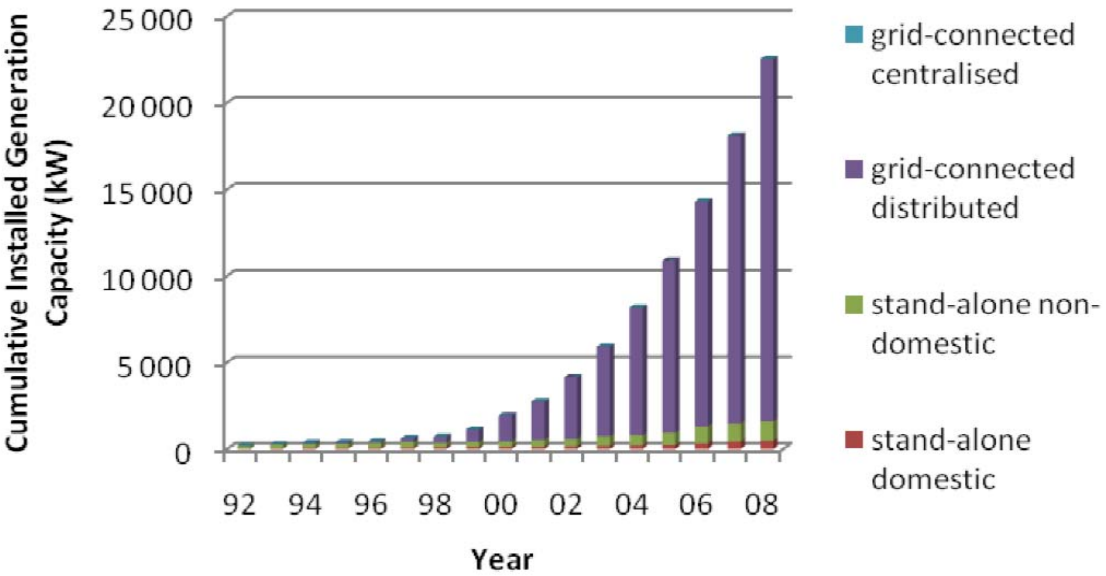


Source: Global Market Outlook for Photovoltaics until 2014, EPIA, May 2010

Growth of the installed PV capacity in the UK has followed the global trend and is shown in Figure 3-3, which has been stimulated by the fall in installed costs and supportive measures such as the Low Carbon Buildings programme and Feed in Tariff. Importantly, Figure 3-3 shows that the proportion of stand-alone (non grid connected)[9] PV installations in the UK is very small and gives justification for Mott MacDonald to consider only grid-connected installations for economic modelling.

[9] Grid connected included PV installations on households connected to the network.

Figure 3-3: Trends in UK installed PV power -1992 to 2008



Source: National Survey Report of PV Power Applications in the United Kingdom 2008 –(DECC)

Installations of grid-connected PV tend to be mounted either on roof tops or on the ground. The mounting system can be designed either as fixed or it can be articulated to track the movement of the sun across the sky. The benefits of tracking installations are yet to be clearly proven and Mott MacDonald has seen a preference for fixed systems, which are chosen for their lower cost and lower complexity. Thus for this modelling exercise we will consider only fixed mounted systems.

There are two key types of semiconductor material used to make solar cells, which can be defined as thin-film and crystalline. Crystalline cells are made from solid crystals of silicon and were the first type of PV technology to be widely commercialised. Efficiencies of 17-19% have been reached, which exceeds current efficiencies from thin film. Crystalline PV has the additional advantage that it does not degrade significantly over time and for these reasons it has dominated the solar PV market up until around 2005 but it is a bulky material and further significant cost reductions in these basic material costs are unlikely.

Thin film technologies use more exotic materials such as Cadmium or Gallium, which enables manufacturers to significantly reduce the amount of material required to create a solar cell. Though this reduces material cost, it has also been shown to reduce energy conversion efficiency. Nevertheless, thin-film silicon cells have become popular for commercial developers due to cost, flexibility, lighter weight, and ease of integration, compared to crystalline cells.

3.3.2 Emergent solar PV technologies

There are a range of emerging technologies that go beyond already discussed foreseen reduction of material intensity in module production, including concentrating photovoltaics (CPV) and organic solar cells, as well as novel concepts with significant potential for performance increase and cost reduction of PV. In this section we aim to review these technology trends and provide an outlook for future cost reductions.

The main source of silicon feedstock for PV cells is virgin polysilicon, purification of which is resource heavy. There are many attempts to replace current processes, based on chemical gaseous purification, by cheaper alternatives including metallurgical purification. Although significant progress has been achieved in recent years and several pilot plants have been put into operation, these new materials have not yet been widely adopted by manufacturers. It is expected that the future will bring more efficient purification processes to the fore.

Examples of other promising novel PV technologies comprise advanced inorganic thin film technologies as well as organic solar cells. Within the organic cells area, there are different technology branches such as the dye sensitised solar cell (a hybrid approach of an organic cell retaining an inorganic component) and fully organic approaches. Organic solar cells are potentially low cost technologies that only recently entered niche applications. Their relevance for energy production en masse, however, remains to be proven. Another emerging PV technology is based on the concept of thermo-photovoltaics whereby a high efficiency PV cell is combined with a thermal radiation source.

As an alternative to plate technologies which use the naturally available sunlight, concentrated photovoltaic (CPV) technology has been proposed. The CPV system makes use of lenses or mirrors to concentrate solar energy onto miniature solar cells that are exceptionally efficient in converting solar energy into electricity. Such arrangement is meant to address the number one problem with the use of solar PV systems – the expensive silicon-based solar panel. Unquestionably, it has another attractive feature of much smaller solar cell area required. Although many journals have already reported significant claims on how effective this technology is in a laboratory setting (efficiencies beyond 40%), the challenge remains on whether this technology will be viable in the commercial market. Several companies have taken up this challenge and are now making significant headway by bringing CPV panels out into the market. The technology is increasingly moving from pilot facilities to commercial-scale applications. Further R&D efforts are required in optical systems design, module assembly and tracking systems.

Intensive efforts are also being directed at achieving ultra-high efficiency solar cells by developing active layers which best match the solar spectrum or which modify the incoming solar spectrum. Both approaches build on progress in nanotechnology and nano-materials. Quantum wells, quantum wires and quantum dots are examples of structures introduced in the active layer. Further approaches deal with the collection of excited charge carriers (hot carrier cells) and the formation of intermediate band gaps. Their market relevance will depend on whether they can be combined with existing technologies or whether they lead to entirely new cell structures and processes. Mass market deployment of such concepts can reasonably be expected in the medium to long term.

Inverter mean time between failure (MTBF)[10] is reported to be in the range of 5 to 10 years, which has obvious consequences on the competitiveness of PV systems. It is expected through R&D next-generation inverters will have higher reliability, and better performance leading to reduced burden on total PV system cost. Ideally, inverters would last as long as other PV system components (i.e. 25 years). In the near-to medium-term, an MTBF of >10 years is likely to be achievable through improving quality control, better heat dissipation, and reducing complexity. Greater design improvements may not be economically viable.

Further foreseen developments include design of common inverters shared by various distributed generation (DG) sources such as fuel cells, PV, small wind. This design will benefit from economies of scale resulting in cheaper renewable energy installations.

[10] This means that the inverter needs to be replaced every 5-10 years. The cost of this replacement is included in the operating cost.

Finally, the operational lifetime of panels is expected to increase from current industry standard of 25 years to 40. Needless to say this will improve the economics of PV installations but this is not considered in the analysis here.

3.3.3 Defining a representative plant for Capex estimate

In order to estimate the capital cost of PV systems in the UK it is necessary to define a representative plant and to specify key features such as the technology used and the installation type. PV is usually installed either on rooftops or on the ground and the two applications are quite different in nature and incur different costs. In addition, the module type can be either thin-film or crystalline and so, for completeness, we have selected four representative cases for estimating the capital cost trends for PV in the UK. All are assumed to be grid connected, although for the household installations, this is via the normal mains supply link.

- Roof mounted thin film;
- Roof mounted Crystalline;
- Ground mounted thin-film; and
- Ground mounted Crystalline.

3.3.3.1 Roof Mounted Crystalline Solar PV

PV systems are sized at around 2 to 4kWp for typical residential installations and up to 100kWp when deployed on the roofs of commercial buildings such as warehouses. In the UK, the feed-in tariff for renewables has been targeted at increasing domestic production of energy and thus, for capex estimations we have considered a typical system size of 2.5kWp using crystalline modules with an efficiency of circa 14% and a single phase string inverter. These technologies are typical of UK residential installations. The modules will be roof- mounted using aluminium rails and roof hooks.

Table 3.8: Key features of a representative plant for the UK

Feature	Description
Capacity	2.5kWp
Module type	215Wp Crystalline module with 14% efficiency
Inverter type	2.5kW Single phase string inverter
Current Capital cost	£2,850/kWp

Source: Mott MacDonald estimates based on recent projects

The capital cost for roof top PV system with crystalline modules has been broken down into the following five high cost items as presented in Table 3.9 below:

Table 3.9: Solar PV crystalline (roof top) system - Capex Estimates (2010)

Cost Item	Estimated Cost per kW	Proportion of cost
Project development (site preparation, planning & consenting)	£300	10%
Modules	£1450	51%
Inverters	£450	16%
Installation (electrical and civil) works	£300	11%
Balance of Plant (BOP) that includes structure, foundations, cables, junction boxes, monitoring equipment, other electrical equipment – transformer, switchgear and lines into nearest substation	£350	12%
Total	£2850	100%

Each cost item is discussed separately below and an explanation is given as the assumptions regarding the current cost and the forecasted adjustment to costs.

3.3.3.2 Ground Munted Crystalline Solar PV

Large ground mounted systems range from 100KWp to more than 20MWp. For capex estimations we have considered a typical system size of 10MWp using crystalline modules with an efficiency of circa 14% and three phase central inverters. A step up transformer and medium voltage (20kV) switchgear is envisaged to export the power generated by the modules to the grid. The modules will be mounted on a fixed support structure made from aluminium and will use concrete or screw foundations.

Table 3.10: Key features of a representative plant for the UK

Feature	Description
Capacity	10MWp
Module type	200Wp Crystalline module with 14% efficiency
Inverter type	500kW, three phase central inverter
Current Capital cost	£2,800/kWp

Source: Mott MacDonald estimates based on recent projects

Capital costs for PV system have been broken down into the following five high cost items as presented in Table 3.11 below:

Table 3.11: Solar PV crystalline (ground mounted) system - Capex Estimates (2010)

Cost Item	Estimated Cost: £ per kW	Proportion of cost
Project development (site preparation, planning & consenting)	300	11%
Modules	1450	52%
Inverters	200	7%
Installation (electrical and civil) works	330	12%
Balance of Plant (BOP) that includes structure, foundations, cables, junction boxes, monitoring equipment, other electrical equipment – transformer, switchgear and lines into nearest substation	520	18%
Total	2800	100%

Source: Mott MacDonald estimates

The capital cost of ground mounted systems is slightly lower than for roof top installations. The base module cost is assumed to be the same because these would be bought in bulk by the developer. Elsewhere, the economies of scale in installation costs for the ground mounted scheme are largely offset by the additional cost of a higher voltage grid connection as shown in Table 3.11 – where the grid connection costs are included within the Balance of Plant category. This conclusion is similar to that reported by the Lawrence Berkeley National Laboratory[11].

Each cost item is discussed separately below and an explanation is given as the assumptions regarding the current cost and the forecasted adjustment to costs.

[11] The Installed Cost of Photovoltaics in the U.S. from 1998-2009 (December 2010)

3.3.3.3 Roof-mounted Thin Film Solar PV

The PV system size for residences is typically in the 2 to 4kWp range. For commercial buildings, the system size can range up to 100kWp or more. For capex estimations we have considered a typical system size of 2.5kWp using thin film modules with an efficiency of circa 8% and single phase string inverter. The modules will be mounted on the roof using aluminium rails and roof hooks.

Table 3.12: Key features of a representative plant for the UK

Feature	Description
Capacity	2.5kWp
Module type	75Wp Crystalline module with 14% efficiency
Inverter type	2.5kW Single phase string inverter
Current Capital cost	£2,650/kWp

Source: Mott MacDonald estimates

Capital costs for roof mounted PV system using thin film modules are cheaper than for crystalline modules, as would be expected. The key cost items have been broken down and presented in Table 3.13 below:

Table 3.13: Solar PV thin film (roof mounted) system - Capex Estimates

Cost Item	Estimated Cost: £ per kW	Proportion of cost
Project development (site preparation, planning & consenting)	300	11%
Modules	1200	46%
Inverters	450	17%
Installation (electrical and civil) works	300	11%
Balance of Plant (BOP) that includes structure, foundations, cables, junction boxes, monitoring equipment, other electrical equipment – transformer, switchgear and lines into nearest substation	400	15%
Total (£ / Kw)	2650	100%

Source: Mott MacDonald estimates

3.3.3.4 Ground Mounted Thin Film Solar PV

Large ground mounted systems range from 100KWp to more than 5MWp. For capex estimations we have considered a typical system size of 5MWp using thin film modules with an efficiency of circa 8% and three phase central inverters. A step up transformer and medium voltage (20kV) switchgear is envisaged to export the power generated by the modules to the grid. The modules will be mounted on a fixed support structure made from aluminium and will use concrete or screw foundations.

Table 3.14: Key features of a representative plant for the UK

Feature	Description
Capacity	5MWp
Module type	75Wp then film module with 8% efficiency
Inverter type	500kW, three phase central inverter
Current Capital cost	£2,600/kWp

Source: Mott MacDonald estimates based recent projects

Capital costs for ground mounted PV system using thin film modules have been broken down into the following five high cost items as presented in Table 3.15 below:

Table 3.15: Solar PV Thin Film (ground mounted) system - Capex Estimates

Cost Item	Estimated Cost: £ per kW	Proportion of cost
Project development (site preparation, planning & consenting)	300	12%
Modules	1200	46%
Inverters	200	8%
Installation (electrical and civil) works	350	13%
Balance of Plant (BOP) that includes structure, foundations, cables, junction boxes, monitoring equipment, other electrical equipment – transformer, switchgear and lines into nearest substation	550	21%
Total	2600	100%

Source: Mott MacDonald estimates

3.3.4 Explanation of Capex model inputs

3.3.4.1 Project Development

Project development cost is currently estimated at about £300/kW. This includes all costs incurred in order to secure project finance, such as environmental impact assessments, yield estimates, design, tendering and contract negotiations. A 2.5kWp system would have a surface area of about 25m^2 and so would still be subject to planning and consenting processes as well as commercial negotiations.

The cost estimate is based on Mott MacDonald's experience in multi MW range PV projects worldwide. Effort and time spent on the engineering and planning of projects is not proportional to system capacity so we have assumed the development costs to be similar to ground mounted systems on a watt peak basis.

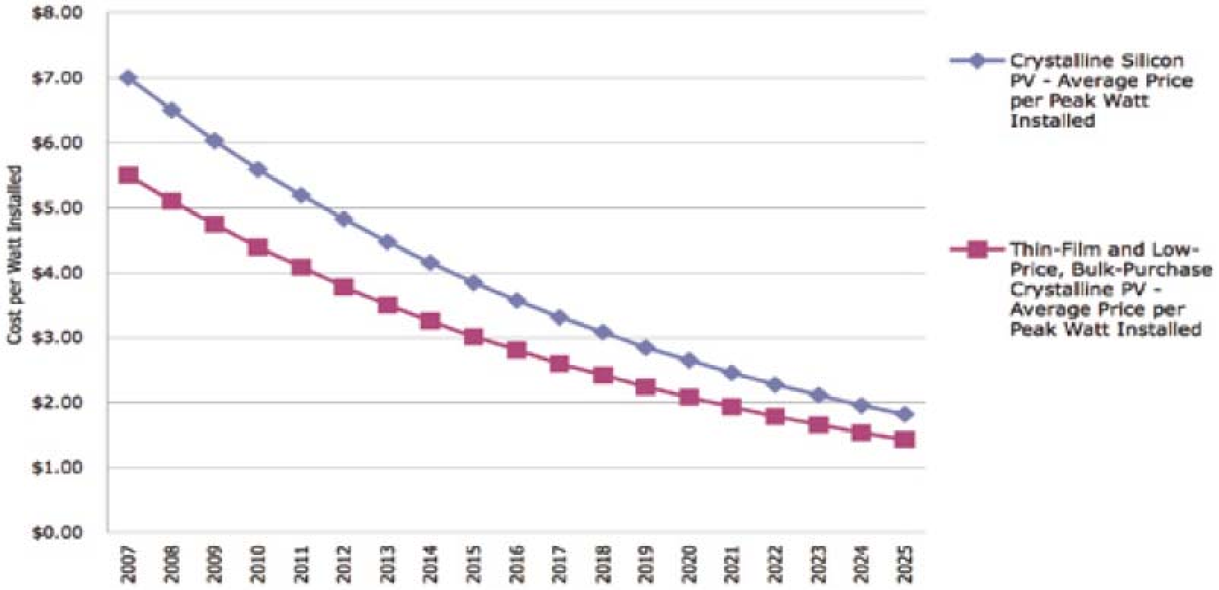
It is expected that up to 2020, the cost of project development is likely to fall as lenders become more comfortable with the commercial risks and project finance becomes less onerous. In addition, the reliability of energy yields is likely to increase as experience is built up and more robust solar resource data will be available and the cost of yield forecasting is expected to reduce. By 2020 it has been assumed that the development costs will fall by over 30%. Further streamlining of project development post-2020 is expected to bring further savings in the order of 30% by 2040.

3.3.4.2 Crystalline Module

Crystalline silicon solar technology was the first type of PV technology to be widely commercialised and is a proven technology with a 30 year track record. The photovoltaic material is a wafer thin layer of either a single crystal of silicon (mono-crystalline) or of a collection of crystals (poly-crystalline). Monocrystalline is the more expensive of the two but has the advantage of higher energy conversion efficiencies and has been selected for developing our representative case because it is commonly used in domestic PV installations.

Monocrystalline PV has been shown to achieve module efficiencies of 15-19% and industry is targeting module efficiency improvements of up to 25% over the coming decades. The cost is widely reported by respected industry bodies such as the International Energy Association to fall by around 70% by 2030 as shown in Figure 3.4, which is typical of other industry predictions.

Figure 3.4: Estimated Crystalline PV System Cost Reductions to 2025



Source: Clean Edge, Utility Solar Assessment (2008)

The current capex price of modules estimated at £1450/kWp (€1750/kWp) is based on Mott MacDonald's experience in recent projects in Europe. The future price is reliant on several key factors including:

- increased production capacity,
- industry learning,
- material prices.

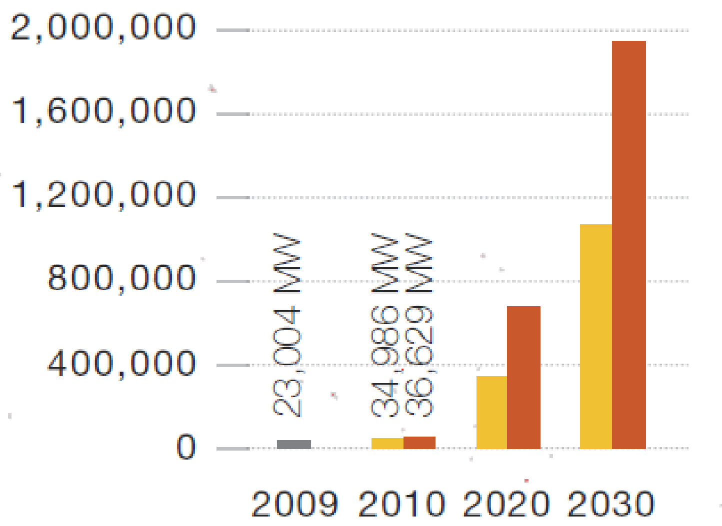
Over the past 30 years the price of PV modules has reduced by 22% each time the cumulative installed capacity (in MW) has doubled[12] and this trend is likely to continue into the future. It was predicted in 2007 that global production of crystalline cells would more than double to 500 MW/year by 2015 (US Dept. of Energy, 2007) and the trends in PV deployment have surpassed such predictions; the international installed capacity of PV systems has increased by 40% annually since 2006 and several large capacity production facilities came online in 2008 and 2009[13].

New manufacturing capacity that began coming on-line in 2008 has led to very large reductions in PV cost and has had an unsettling effect on the market as project developers delay their projects in order to benefit from even lower future PV prices. Indeed, the supply market is perhaps oversubscribed at present, which has led to the large price falls. The ramp up in production capacity of module manufacturing has lead to a reduction in the unit production cost of crystalline modules and a costs of crystalline PV as low as $1/Wp are reported to be imminent.

[12] EPIA, Solar Voltaic Energy Empowering The World, February 2011 and available online at http://www.greenpeace.org/international/Global/international/publications/climate/2011/Final%20SolarGeneration%20VI%20full%20report%20lr.pdf

[13] Renewable Energy World, December 2009.

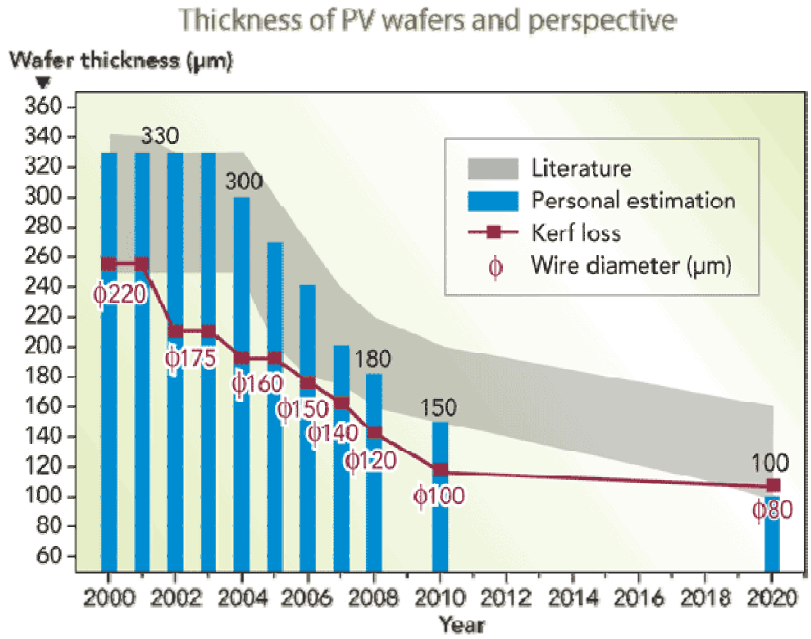
Figure 3.5: Expected Growth in Global PV installation (high-low range)



Source: EPIA, Solar Voltaic Energy Empowering The World, February 2011

Targeted research and development is ongoing to reduce the material intensity of crystalline modules. Silicon wafers currently represents up to 40% of the cost of a crystalline PV module so improved manufacturing methods and efficiencies are driving reductions in the quantities of materials used in solar cells. Figure 3-6 gives shows the trend in wafer thickness over the past decade and supports the view that material intensity should continue to fall.

Figure 3-6: Wafer thickness in crystalline modules



Source: Photovoltaics World Nov/Dec 2010

Considering that Module manufacturing is undergoing rapid industry growth and development, and taking into account industry learning, supply chain development and material savings, we project strong short term reductions in module cost of about 70% by 2020 and a further almost 80% reduction between 2020 and 2040.

Our predictions are broadly in line with those of a recent and respected industry report by the European Photovoltaic Industry Association (EPIA) and Greenpeace International (February 2011), which lends weight to our forecasts.

3.3.4.3 Thin film modules

The thin film technology, in its most common form, comprises a thin silicon layer deposited on a low cost flexible substrate. The lower consumption of silicon reduces the costs considerably and the trade-off is that the efficiency is considerably lower than for crystalline modules, approximately 6-12% compared to the 15-19% efficiency of crystalline modules. However, thin film technologies using more exotic materials such as the CIGS module (copper, indium, gallium, diselenide/disulphide) and CdTe (cadmium telluride) show potential for efficiencies that may rival crystalline technology. Table 3.16 shows a recent assessment of efficiencies available for thin film modules, both commercially and in the lab.

Table 3.16: Efficiency comparisons of the key thin-film technologies

Thin Film Technology	Record Commercial Module Efficiency	Record Lab Efficiency
Amorphous Silicon	7.1%	10.4%
a-Si/µ-Si	10%	13.2%
CdTe	11.2%	16.5%
CIGS	12.1%	20.3%

Source: European Photovoltaic Industry Association. "Solarvoltaic Electricity Empowering the World" 2011

Although the thin film technology is less efficient that crystalline technology, it is the cheapest PV technology and has demonstrated successful application in large ground mounted systems. Many commentators are projecting that the market share of thin film modules will increase substantially in the medium term – Renewable Energy World quotes a doubling to 31% by 2013[14]. R&D efforts in this technology are currently focused on achieving a reduced cost of $0.8 to $1 per Wp (£0.5 to £0.6/Wp) by improving cell efficiencies to 10 -12% by 2015 (IEA Solar PV Technology Roadmap). First Solar in the US claims production costs of less than $1/Wp[15].

Mott MacDonald's experience in recent projects in Europe suggests costs are much higher than the claimed level, with modules prices around £1200/kWp (€1450/kWp) being typical.

We have assumed that a combination of a scale up in production facilities, reduced material costs and efficiency improvements will bring about the deep reductions that the solar industry is expecting. Our central projection is that module costs will reduce by over 70% by 2020 and almost another 80% by 2040. This takes module costs down to a small fraction of current levels and so fundamentally changing the component cost build up of solar PV on an installed basis.

[14] http://www.renewableenergyworld.com/rea/news/article/2009/11/thin-films-share-of-solar-panel-market-to-double-by-2013

[15] First solar press release, *First Solar Passes $1 Per Watt Industry Milestone,* February 24 2009.

3.3.4.4 Inverter

Inverters convert the DC power generated by a PV module to AC power and are therefore essential for grid-connected PV as it makes the energy generation compatible with the electricity distribution network and most common electrical appliances. The current price of string inverters (circa 2.5kW) is estimated at around £450/kWp based upon Mott MacDonald's experience in recent projects in the UK and Europe.

The price of inverters has followed a similar trend to that of PV modules and has decreased substantially over the past 30 years. There is no evidence to suggest that the learning curve will not continue and inverters remain an area of focused R&D efforts. The promising attribute of inverters is that they are common to all module types and so whether thin film, crystalline or an emerging technology wins the race to be the module of choice in the future, inverters will inevitably follow the trend.

With the expansion of the PV sector in the few years between 2005 and 2008, manufacturing capacity was a limitation in allowing inverter suppliers to keep up with demand. The high technological expertise required to manufacture inverters coupled with the fast-moving nature of technological advancement and efficiency improvements act as a market barrier to new entrants. It has been reported that the top ten inverter manufacturers produce more than 80% of the inverters sold on the market[16]. Nevertheless, the continued growth of the PV market has meant that there are large incentives for inverter manufacturers to increase production and to encourage new market entrants, especially from the Far East. We expect to see substantial cost savings from mass production and supply chain savings between now and 2020.

One of the areas of current research involves replacing the large centralised inverter that is standard with current PV installations with micro-inverters that are integrated within the module. Such a move would also reduce the amount of Balance of Plant works necessary. The other area of key research is to extend the life of inverters, which currently require replacement every five to ten years. Extending inverter life will lead to significant operational savings. These costs are incorporated in the operating costs assessment.

Overall, we are estimating that inverter costs will halve by 2020 and halve again by 2040 as new market entrants, more established supply chains, increased competition and technological advances bring deep cost reductions.

3.3.4.5 Balance of Plant (BoP)

BoP accounts mainly for the cost of the mounting structure, cables, junction boxes, monitoring equipment and other electrical equipment such grid interconnection panels and meters. Roof mounted systems are significant cheaper since they can be connected to the distribution grid without the need for switchgear and Medium Voltage connections. Otherwise, the BoP costs of roof mounted systems are quite similar to ground mounted systems on a cost per kW basis as although the roof mounted systems are more labour intensive to install, they do not require the same planning and development costs or foundation cost. The current price of BoP is estimated at £350/kWp. In contrast, ground mounted system cost around £520-550/kWp, because of the heavier duty connection requirements.

The cost of structures, cables and junction boxes is expected to reduce until 2020 with the bulk of this reduction attributed to improved module efficiencies that will result in less area per kWp installed and therefore reduced material intensity (steel, aluminium and copper). Similarly, although the cost of

[16] EPIA, Solar Voltaic Energy Empowering The World, February 2011

transformers and medium voltage switchgear may not change significantly, the increase in module efficiencies will result in fewer cables and junction boxes per kWp, thereby reducing the overall cost of electrical infrastructure for ground mounted system too. Further savings will come from better design of the supporting structures (i.e. less kg/Wp or simpler, faster installation) and also use of frameless panels.

The reduction in overall weight and the reduced need for strong supporting structures is likely to result in the development of lighter and cheaper fixings and cost reductions for BoP. Our central case assumes these costs reduce by 33% by 2020 and a further 33% by 2040.

3.3.4.6 Installation

The cost of installing PV is estimated at £300-350/kWp, with higher values for ground mounted installations, given the need for significant civil works. This is clearly a labour intensive activity, and one where the scope for cost reduction will be linked to the energy density of the panels as much as the application of more streamlined assembly procedures and practiced installation teams. We are estimating a cost reduction of 35% by 2020 and 43% between 2020 and 2040.

Conclusion

PV costs for all the main installation types are expected to see very significant cost reductions, led by the module costs which will shrink from around half of current installed costs to some 12-18% of costs in 2040 under the MML central projection. Total installed costs for all four installation types are projected to more than half by 2020 and then halve again by 2040. This would take PV costs to between £650-£700/kW by 2040. As today, the costs of the systems are very close, although the component breakdown is a little different. Table 3.17 shows the projections for the four installation types by component under this central projection. This is of course, just one of many plausible projections. The main uncertainties relate mainly to how fast the non-module costs can be brought down, as module costs themselves are set to become a small fraction of their current level.

Table 3.17: Projected costs per kW of installed PV to 2040 for four main installation types under central case using MML assessments

PV type/ mounting and components	2011	2020	2040	% of 2011 costs in 2020	% of 2011 costs in 2040
Crystalline roof mounted					
Site prep/ licensing	300	204	184	68%	61%
Modules	1450	412	113	28%	8%
Inverters	450	212	102	47%	23%
Installation works	300	194	109	65%	36%
BoP	350	237	159	68%	45%
Total	2850	1258	667	44%	23%
Crystalline ground mounted	**2011**	**2020**	**2040**	**% of 2011 costs in 2020**	**% of 2011 costs in 2040**
Site prep/ licensing	300	204	184	68%	61%
Modules	1450	406	112	28%	8%
Inverters	200	94	44	47%	22%
Installation works	330	213	120	65%	36%
BoP	520	352	236	68%	45%

PV type/ mounting and components	2011	2020	2040	% of 2011 costs in 2020	% of 2011 costs in 2040
Total	2800	1268	696	45%	25%

Thin film roof mounted	**2011**	**2020**	**2040**	**% of 2011 costs in 2020**	**% of 2011 costs in 2040**
Site prep/ licensing	300	204	184	68%	61%
Modules	1200	345	74	29%	6%
Inverters	450	213	101	47%	23%
Installation works	300	194	109	65%	36%
BoP	400	270	181	68%	45%
Total	2650	1226	650	46%	25%

Thin film ground mounted	**2011**	**2020**	**2040**	**% of 2011 costs in 2020**	**% of 2011 costs in 2040**
Site prep/ licensing	300	204	184	68%	61%
Modules	1200	354	72	30%	6%
Inverters	200	93	44	47%	22%
Installation works	350	226	127	65%	36%
BoP	550	370	248	67%	45%
Total	2600	1247	675	48%	26%

Source: Mott MacDonald estimates (central case)

Outlook for levelised costs

Taking the above capital cost assessments, our central case projections for other plant cost and performance parameters and Oxera's central discount rate case (both outlined in Chapter 6) gives an indicative current levelised cost of £330-375/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 gives a levelised cost in 2020 and 2040 of £137-198/MWh and £63-120/MWh, respectively. The comparable figures using the learning curve approach are £145-200/MWh and £43-78/MWh. This is only considering capex uncertainty. 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.

3.4 Biomass

3.4.1 Introduction

Biomass is any organic matter that is available on a renewable or recurring basis and includes forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants and municipal and industrial wastes. Biomass can be used in solid form or converted into gaseous or liquid form before use.

The biomass sector is varied both from a technology and an input fuel perspective. The technologies range from those that are proven commercially (for example, solid fuel combustion) through to those that are entering commercial demonstration and proving commercial reliability (for example, gasification). The situation is complicated by the combinations of technologies, fuels and sizes with some combinations of integrated systems only now in the emerging stages of commercialisation. The impact of this is a large spread on capital costs from £2,200/kW through to over £7,200/kW.

To effectively develop productive energy from biomass resources a number of considerations need to be addressed such as availability of resource; economics of collection, storage and transportation; evaluating and delivery of technical, environmental and publicly acceptable options for conversion into useful electricity (and heat).

The availability of the feedstock in close proximity to the biomass power project is a critical factor in the efficient utilisation of this resource and will often dictate the technology and size of the proposed project in addition to dramatically impacting on the financial model (for example, quantity of fuel needed, maintenance cycle, cost of fuel/gate fee).

The main biomass fuels available include:

- Energy crops: short rotation coppice willow or poplar and miscanthus (some energy crops will likely be available from the world market)
- Crop residues: straw from wheat and oil seed rape
- Stemwood: hardwood and softwood tree trunks
- Forestry residues: wood chips from branches, tips and poor quality stemwood (some forestry residues will likely be available from the world market)
- Sawmill co-product: wood chip, sawdust and bark (some sawmill co-product may be available from the world market)
- Arboricultural arisings: stemwood, wood chips, branches and foliage
- Waste wood: clean and contaminated (some waste wood may be available from the world market)
- Organic waste: paper/card, food/kitchen, garden/plant and textiles wastes
- Sewage sludge: from waste water treatment
- Animal manures/slurry: from cattle, pigs, sheep and poultry
- Landfill gas: captured from biodegradable waste decomposition
- First generation bio-fuels: ethanol (from sugar and starch crops), bio-diesel from oil crops
- Algae: oil and biomass from photosynthetic algae (are emerging as a potential fuel source).

As noted above many of the technologies being considered as part of this study are well established. Learning rates vary for individual components that will vary with main areas of improvement generally being focused on the handling and management of fuels, development of new 'cleaner' fuels and an improved understanding and experience of integration and operation of technologies.

The technologies considered in this study are summarised in Table 3.18.

Table 3.18: Summary of technology assumptions

Technology	Unit Size (MWe)	Assumed number of units	Conversion technology	Conversion technology commercialisation	Prime mover technology	Prime mover technology commercialisation
Advanced AD sewage sludge	5	1	Anaerobic digestion	Commercially proven but room for improvement in gas production speed and quantity (partially linked to fuel)	Gas engine	Commercially proven albeit with few examples of AD linked at this size
Food waste AD	1.5	2				
Manure/Slurry AD	1	1				
Energy Crop AD	1	2				
Wood Grate	10	1	Fixed bed	Commercially proven	Steam	Commercially proven

Technology	Unit Size (MWe)	Assumed number of units	Conversion technology	Conversion technology commercialisation	Prime mover technology	Prime mover technology commercialisation
			boiler		turbine	
Wood Gasification	1	2	Fixed bed gasifier	Emerging / demonstration	Gas turbine	Commercially proven but not with low heating value biogas
MSW-SRF Pyrolysis	1	2	Pyrolysis	Commercial demonstration	Gas Engine	Commercially proven albeit with few examples of pyrolysis linked at this size
Wood BFBC	40	1	Fluidised bed boiler	Commercially proven	Steam turbine	Commercially proven
Wood CFBC	150	1	Fluidised bed boiler	Commercially proven	Steam turbine	Commercially proven
Waste wood Grate	40	1	Fixed bed boiler	Commercially proven	Steam turbine	Commercially proven

Source: MM Assumptions

3.4.2 Anaerobic Digestion (AD)

3.4.2.1 Technology Description

Anaerobic Digestion (AD) is a process whereby bacteria break down organic feedstocks in the absence of oxygen to produce a gas that is rich in methane. The resulting biogas can be used in direct combustion to generate heat and/or power or further refined to produce bio-methane for vehicle fuel or injection into the gas grid network. The by-product is an organic digestate that has potential to be returned to the land as soil improver[17].

The technological developments in AD are not so much associated with the generation equipment but more with the Digester technology and the clean-up of the resultant gases before combustion. Electricity generation from biomass is often achieved using gas engine generators, which are largely based upon established diesel technology. Only relatively minor adjustments are necessary for the different fuel type. Leading gas engine suppliers offer an energy conversion efficiency of up to 42% and no significant efficiency increases are expected in the future. Heat can also be used (as covered later).

[17] Not possible when the feedstock contains hazardous materials

Figure 3-7: Farm-based bio-digestor. Germany

Source: Mott MacDonald

The digestion process must be designed to meet the project-specific demands for feedstock type and retention time (the time that the feedstock is in the digester). Standardised plants are available in Continental Europe for processing silage-based feedstocks but in projects where the predominant feedstock is something more unusual such as municipal waste or abattoir waste, for example, the process needs to be changed to reflect the properties of the feedstock.

The challenges faced by technology providers trying to achieve the same process under controlled conditions are more to do with husbandry of the bacteria, controlling the conditions such as pH, heat and trace element concentration, whilst increasing the loading rate to make the Facility more economic. The next ten years are likely to bring an increase in operational experience with various feedstocks in which time it may be possible to develop a set of standardised plants to suit. Once this occurs economies of scale are likely to come into place and the cost of plant is likely to fall; as is already being seen with silage-based facilities.

The current capital cost of an AD is quoted in continental Europe at around £ 4,000/kW but experience from early projects in the UK has put the cost typically in the range £5-8 million/MW, which reflects an emerging industry with limited supply routes and a reliance on imported technology. With the proper incentives, the biogas industry in the UK has potential to expand and costs could be expected to fall in line with those of our European cousins. It is noted that costs for sewage sludge AD plant can be significantly lower, in the order of £3000/kW, however, the opportunities for such digesters are likely to be limited in the UK due to the link to the water treatment process and the pipeline of projects in this area.

Bio-digesters are a proven technology but there is still some experimentation going on with regards to scale and market chain management. The waste industry in Europe is in a state of flux as the effects of the EU landfill directive (1999/31/EC) and EU waste directive (2006/12/EC) make their effects felt. The current trend of waste companies is towards increased composting and anaerobic digestion of organic material to divert it from landfill. As this trend continues there may become greater competition for feedstock and the market may change substantially from today's where some anaerobic digestion facilities can charge a gate fee for accepting waste to site. These developments are market based rather than technology based and will not be covered in any more detail in this report.

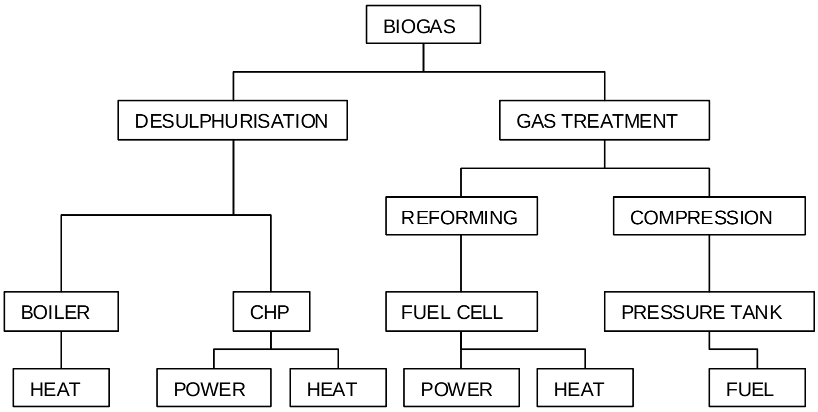
The overall energy efficiency of AD schemes can be dramatically improved if a use can be found for the heat available as a by-product of the electrical generation. In continental Europe and especially Germany, Denmark and Austria, it is becoming more popular to link anaerobic digestion facilities to existing local heat distribution networks. The challenges to do this in the UK are largely ones of capital costs and of public acceptance where we do not have a history or network of public heat networks. The cost of installing heat distribution is an important factor in their likely future uptake. Heat distribution mains have a diameter comparable to other water pipes and often require to be laid pre-insulated underground (to avoid damage) which is potentially disruptive and costly. A more viable approach is to link a few large industrial process heat users, which reduces the capital cost of the pipework (and metering) but also very importantly increases the annual load factor. It is likely that we will see an increase in heat recovery and distribution in the UK where AD plants are sited near large loads although this will not be limited to biomass technologies. For the purposes of this analysis we have not included any costs for heat distribution, as the comparisons are all on an electricity only basis.

Biogas from the digestion process is a combination mainly of methane (50 to 65%) and CO_2 with smaller amounts of hydrogen sulphide (H_2S) and ammonia (NH_3). Trace amounts of hydrogen (H_2), nitrogen (N_2), saturated or halogenated carbohydrates and oxygen (O_2) are occasionally present in the biogas. Usually, the gas is saturated with water vapour and may contain dust particles and organic silicon compounds (e.g siloxanes). The properties and composition of biogas depend on the feedstock and the type of digestion process. Typically the calorific value (CV) of biogas is around half that of natural gas, and so a greater volume is required to give the same energy output. It is possible to 'upgrade' the gas (remove non-combustibles) to increase the methane content and hence the CV. It is also necessary to remove impurities such as hydrogen sulphide (H_2S) before combustion.

The AD process produces gas with relatively low energy content from dilute energy sources, and hence significant volumes are required to produce a useful biogas output. In addition the fuel sources typically used (manure, slurry and food waste) tend to be scattered. Because of this AD plants tend to be relatively small scale, and even larger plants with on site electricity generation do not usually exceed a few MW of electrical capacity. A proportion of the heat is usually required to heat the digesters (to maintain mesophillic temperatures), but there is often a significant surplus that can be used for producing hot water. Given the relatively low output, AD plants must either be located close to heat demand, or the biogas must be transported to an offsite location by some means. It is possible to upgrade biogas to pipeline standard 'bio-methane' for injection to the natural gas network. Upgrading is typically done using the 'pressure swing adsorption' process which removes the vast majority of CO_2, H_2O, H_2S, N_2, O_2 and other impurities, the resulting purified gas is known as 'bio-methane'. The gas CV must closely match that of the natural gas in the network, if the quality is acceptable the gas is odourised, compressed and injected to the distribution network.

Biogas can also be compressed and used as a renewable transport fuel. Biogas can be used in all natural gas appliances provided that upgrading of the gas quality is carried out. The main potential routes for biogas utilisation are depicted in Figure 3-8.

Figure 3-8: Biogas Utilisation



Source: (BERR 2008)

The main technologies involved in biogas treatment are largely established and only incremental improvements are expected although it may be expected that such facilities will become available at a smaller scale in order to suit the relatively low biogas yield of AD facilities.

Whilst the technology for Anaerobic Digestion is largely established, it is the social acceptance[18] and market structure that will require the largest developments as AD grows to contribute a greater share of energy to the UK. Given the technical characteristics which restrict the plant's scale of only a few MW and the limits on feedstock supply, the consensus view is that it cannot be expected to be deployed at the same scale as other technologies like offshore wind.

3.4.2.2 Explanation of Capex model inputs

The AD Options considered in this study alongside the respective total indicative capex costs are summarised in Table 3.19.

Table 3.19: AD Capital Cost Breakdown

Item	Advanced AD Sewage Sludge		Food Waste AD		Manure- Slurry AD		Energy Crops AD	
	Est. cost per kW	Proportion of cost	Est. cost per kW	Proportion of cost	Est. cost per kW	Proportion of cost	Est. cost per kW	Proportion of cost
Consultancy / Design	£469	18%	£916	13%	£560	11%	£858	13%
Civils	£339	13%	£1,106	15%	£866	17%	£1,036	15%
Fuel handling / prep	£443	17%	£1,452	20%	£917	18%	£1,361	20%
Electrical / BoP	£182	7%	£582	8%	£408	8%	£545	8%
Converter system	£782	30%	£2,526	35%	£1,834	36%	£2,366	35%
Prime mover	£391	15%	£696	10%	£509	10%	£652	10%
Total	**£2,605**	**100%**	**£7,278**	**100%**	**£5,094**	**100%**	**£6,818**	**100%**

[18] AD plants are often objected to on the grounds of visual intrusion, odour, transport disruption, etc

The capital cost breakdown shown above picks out the main components of biomass schemes. The costs have been built primarily from EPC costs known by Mott MacDonald, where appropriate this has been supplemented by information in the public domain and judgement of our engineers.

The key elements incurring costs are the digesters and associated processing and clean-up elements. These comprise in the order of 30-35% of the capex costs. Other major components are the fuel handling and preparation (approximately 20%) and the prime mover which is in the order of 10-15% of the capex costs. It is noted that the selection of fuel can impact heavily on the project cost due to additional stages such as pasteurisation being required in order to meet with UK legislation. In general terms civil costs are typically in the range of 10-20%; electrical costs range between 15-25% with mechanical components accounting for upwards of 75%.

Consultancy / Design

The range of costs associated with the development of these technologies is based on Mott MacDonald's experience in supporting projects. The costs reflect the elements associated with project development, consents and planning. The variance between the costs reflects the relative complexities of different schemes and the respective fuel supply arrangements. The total costs of sewage sludge are on a subtly different basis as this cost excludes the associated costs of the water treatment works producing the sludge. Food waste is potentially more complex to design and consent due to the potential variety of fuel, volume of waste and complexities in securing adequate fuel supply and handling.

It is expected that to 2020 the costs of development will likely fall marginally. Such reductions will arise as the development and consenting process becomes more experienced with these technologies and the associated components. For example, a significant barrier for food AD is securing, collecting and supplying of the fuel. With more interest in this technology, the benefits and the changing incentive/regulatory structure in the UK there is more interest in the development of these technologies.

Post 2020 it is anticipated that there is likely to be a reduction in the availability of fuel sources and optimal sites and as such the opportunities for cost reductions will be smaller.

Civils

Cost estimates for the civils components are based on Mott MacDonald's experience and estimates generated from EPC costs. These tend to be similar in proportion for all the variations of projects considered. In relation to sewage sludge we have assumed that a large proportion of the fuel production and civil works is effectively part of the waste water treatment process and thereby excluded from the costs presented here. With on-farm AD the overall civil works costs are smaller but the proportions larger which reflects the assumed smaller installed capacity for this type of plant.

To 2020 savings associated with both the quantity of materials and the maturity of designs are anticipated as more of these plants are developed. Beyond 2020, we consider that additional savings will be possible as changes in fuels used / development of new fuels increase the efficiency of process and help reduce the ratio of civils to the installed capacity.

Fuel Handling and Preparation

The pre-treatment and on-site handling/processing of fuels can be a significant proportion of biomass capital costs. The processing system for AD can be manual but will likely be automated for the larger capacity schemes. Common steps include separation, sizing, removal of non-combustibles (depending on source of fuel), control of moisture content, dewatering (once processed) and handling of process by-products (typically for onward sale).

To 2020 it is anticipated that there are opportunities for the process of fuel handling to mature and improve as more experience is gained from processing certain fuels and through the development of more AD schemes. Beyond 2020 opportunities for cost savings arise primarily through the development of new fuels increasing the efficiency of this process through a reduction in the need for preparation and handling.

Electrical and Balance of Plant

These costs cover the equipment necessary for connection of the plant to the grid but does not include the costs of transmission lines. The balance of plant costs include the cost of control and monitoring systems along with other costs that are not easily defined into other categories. Both to 2020 and beyond 2020 the opportunities for cost reductions in this area are considered modest. The systems are relatively mature with some potential savings on the controls associated with biogas treatment as new fuels potentially reduce the need for pre-combustion gas cleanup.

Converter System

The converter system includes the anaerobic digesters, gas collection systems and some of the gas treatment systems. The costs have been developed from EPC cost estimates that Mott MacDonald hold supplemented by expert judgement for plant of these sizes.

AD draws on well established principles and technologies, however, there is room for development and cost reductions driven by increasing scale from sub-MW to MW sized units, better understanding and control on the digestion processes and greater proving of the integration of technologies at the larger scale in the UK. It is expected that to 2020 and beyond improvements in the conversion process of the fuel to the gas (and by-product) will result in the greatest area of potential reduction in capital cost for the AD process. This relates to both the development of new fuels but also the design and learning through testing and demonstration of specific UK fuels. Improvements in the digestion process may help to optimise the gas production, perhaps reducing the residence time for the fuel processing thereby allowing the production of greater quantities of gases. Realising such fuel related savings is also a combination of the input fuels and better use and control of the process (enzymes, pH, temperature etc.). Minor savings may be possible through improvements in equipment design and the reduction of materials in manufacture although, as with other biomass technologies, such impacts are anticipated to be relatively minimal.

The improvements in fuels could, for example, result in a reduced need to clean the gas prior to combustion removing contaminants that can corrode / erode and reduce the heating value of the gas through combustion. This would in turn lead to improved operation and a reduction in maintenance requirements.

Prime Mover

The prime mover relates to the power generation technologies and includes the converter and any in-line elements such as particulate matter filters etc. Gas engines have been assumed for this component as these represent the most efficient method by which the gas can be converted to electricity (and heat, if appropriate). They are fast to start up and have a good load following ability. There is extensive field experience and numerous models available in the market.

This technology is mature and there may be developments in smaller scale technologies, such as fuel cells, that will increase applications in the future. In general improvements in the production of cleaner fuels have been assumed to result in a reduction in cost over time as incremental improvements are achieved and machines from lower cost areas become demonstrated for this application.

3.4.2.3 AD Conclusions

The technologies involved in the production of electricity via the AD process are well established and to an extent demonstrated. There are opportunities to demonstrate integration with particular fuel streams and at larger scales. Over longer timescales the breakthroughs in technology could include modularised AD units but the majority of step changes are likely to involve fuel related developments and the ability to better control the biological processes. Examples of the latter could include bacteria with a greater tolerance to process changes and fuel types or in a reduced residence time. This could also include bacteria that are able to produce cleaner gases which could result in the ability to directly combust the syngas in engines, resulting in costs reductions through the removal or reduction of the gas clean-up phase. The outlook for AD capital costs is summarised in Table 3.23.

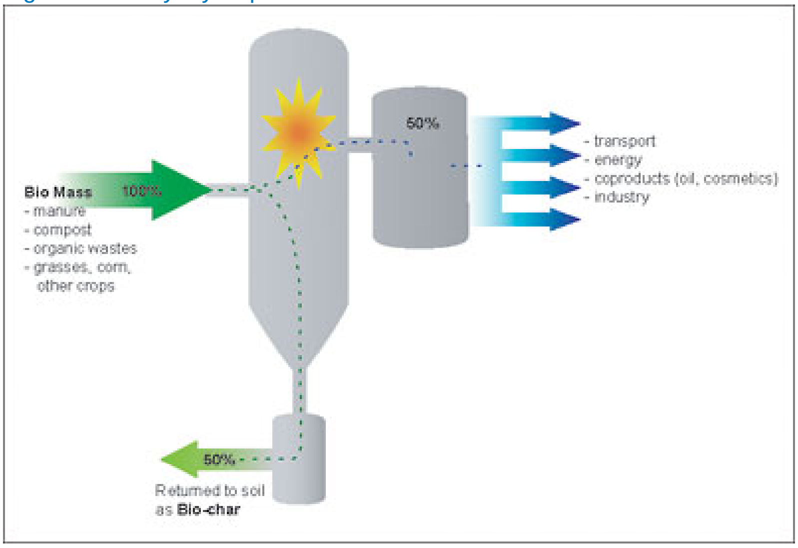
3.4.3 Pyrolysis

3.4.3.1 Technology Description

Pyrolysis is the heating of a material in the complete absence of air (or oxygen) that results in a gas, liquid and solid, all of which are combustible and can be used for energy generation. The proportions of gas and liquid, in particular depend on the temperature and chemical conditions within the pyrolyser. The reactions that occur within the material on heating will not then produce any heat output, so heating has to be applied externally. Provision of this heating will usually be by taking a significant side-stream of the combustible products produced, or of the electrical output of down-stream generation.

‘Fast pyrolysis’, usually in small reactors, produces mainly pyrolysis oil from waste or biomass feedstocks. The minority pyrolysis gas produced can often be used to heat the process. Pyrolysis oil can be refined for other uses, notably as a substitute for diesel oil in transport applications but it would not usually be used for electrical power generation.

Figure 3-9: Pyrolysis process



Source: www.carboncommentary.com

The pyrolysis process produces a gas with a similar CV to oxygen gasification (12 -27MJ/m3), but also produces a solid component (char) and a liquid (bio-oil). The proportions of each phase depend on the conditions within the pyrolyser and the residence time. The higher CV is due to the lack of nitrogen as no air is used in the process. However, the gas has very high levels of tar which condense on cooling. As a result if the gas produced is intended to be combusted directly, then gasification is typically employed as it produces a cleaner gas.

Pyrolysis char contains a large part (>20%) of the input chemical energy of the feedstock. It is therefore important to find a beneficial use for this material. Possibilities include the use as 'activated carbon'; use as a fuel in a solid fuel process (including power generation plants); or carbon sequestration as 'biochar' for soil improvement. One possible future technological development might be adjustment of the pyrolysis conditions and atmosphere, and/or the addition of catalysts, to minimise or eliminate the char production. Experiments of this sort are currently at laboratory scale only, so even if successful would take many years to influence the commercial technology.

Pyrolysis is known as an 'advanced combustion technology', where the heating and combustion phases of normal incineration are separated. It is a relatively complex process that is sensitive to the fuel input and the process design. As operational experience grows then it is likely that design improvements will lead to better reliability, which has caused the slow uptake of pyrolysis generation. Waste and biomass pyrolysis (excluding fast pyrolysis) generally requires pre-treatment of material to remove metals and other inert material that may otherwise upset the pyrolysis equipment. Fuels are also generally mascerated and dried to give a homogeneous high-CV feedstock. The costings here are based on using a mixed municipal solid waste (MSW) and solid recovered fuel (SRF).

3.4.3.2 Explanation of Capex model inputs

An indicative capital cost breakdown for pyrolysis of municipal waste is provided in Table 3.20.

Table 3.20: Capital Cost Breakdown for a Pyrolysis Plant using Municipal Waste

Item	MSW-SRF Pyrolysis	
	Est. cost per kW	Proportion of cost
Consultancy / Design	£166	5%
Civil works	£438	14%
Fuel handling / preparation	£178	6%
Electrical / Balance of plant	£156	5%
Converter system	£1,875	60%
Prime mover	£313	10%
Total	£3,125	100%

Source: Mott MacDonald estimates

The key capex related elements of pyrolysis centre of the converter system (the pyrolysis unit) accounting for approximately 60% of the capex costs. This cost includes gas clean-up prior to combustion. Breakthroughs in gas cleanup technologies could increase the potential for direct combustion of syngas and reduce the overall costs of production. The generator and civils elements comprise comparatively smaller parts of the costs (10% or less and under 15% of the capex costs respectively).

Consultancy / Design

These costs reflect the elements associated with project development, consents and planning. The modular format assumed for the technology supports lower development costs although it is anticipated that some improvements can be achieved as these technologies become more widespread and confidence and experience grow. Beyond 2020 modularisation and potential lower cost production could result in additional efficiency gains in the consultancy and design.

Civils

Cost estimates for the civils components are based on Mott MacDonald's experience. Evolution of these costs is predicted to result in reductions associated with familiarity. Some material savings are anticipated although the benefits are estimated to be small as with a modular system the opportunities for design improvement are comparatively limited. Beyond 2020 it is estimated that additional savings may be realised again related to the more efficient delivery of modular systems and progress in materials use.

Fuel Handling and Preparation

Fuel handling and processing requirements are dictated by the pyrolysis unit and the fuel input often requires sorting, drying, segregation and blending. Note these costs exclude the costs associated with mechanical biological treatment [19](MBT) producing solid recovered fuel (SRF). This process is assumed to

[19] This is sophisticated compost heap.

be automated with some manual handling at the start of the process. The feedstock is assumed to be formed primarily from solid recovered fuel which reduces some of the associated costs. To 2020 modest reductions in the capital cost are anticipated which are estimated to be driven from the production of better quality solid recovered fuels and improvement gains through the experiences from other plant. Beyond 2020 improvements in the handling of fuels are anticipated to continue as the process of fuel sorting and provision improves significantly.

Electrical and Balance of Plant

These costs cover the equipment necessary for connection of the plant to the grid but does not include the costs of transmission lines. The balance of plant costs include the cost of control and monitoring systems along with other costs that are not easily defined into other categories. Both to 2020 and beyond 2020 the opportunities for cost reductions in this area are considered modest. The systems are relatively mature with some potential savings on the controls associated with syngas treatment as new fuels potentially reduce the need for pre-combustion gas cleanup.

Converter System

The converter system includes the pyrolysis plant, gas collection systems and solid/liquid collection systems. The costs have been developed from EPC cost estimates that Mott MacDonald hold supplemented by expert judgement for plant of these sizes. The converter system is the standout element of the capital costs. The evolution of costs to 2020 are anticipated to be driven through two areas: modularisation of the plant (as is emerging) and experiences gained as this technology demonstrates commercial deployment in the UK. Beyond 2020 these improvements are anticipated to continue as economies of scale in the modular production support a reduction in costs.

Prime Mover

The prime mover relates to the power generation technologies and includes the converter and any in-line elements such as particulate matter filters etc. Gas engines have been assumed for this component as these represent the most efficient method by which the gas can be converted to electricity (and heat, if appropriate). They are fast to start up and have a good load-following ability. There is extensive field experience and numerous models available in the market.

3.4.3.3 Pyrolysis Conclusions

Pyrolysis is still in the pre-commercial demonstration phase and plants are typically 1 to 3 MWe in size. Future scale-up of the unit sizes is thought to be very limited, so the implementation of large projects would require multiple small modules. Modularised systems could result in cost reductions as the technology becomes proven and demonstrated as it increases the potential for such parts to be mass produced in lower cost jurisdictions. The current capital cost of pyrolysis generation of MSW-SRF is estimated at about £3,000/kW and our view is that future costs should fall below £2000/kW by 2040 – see Table 3.23

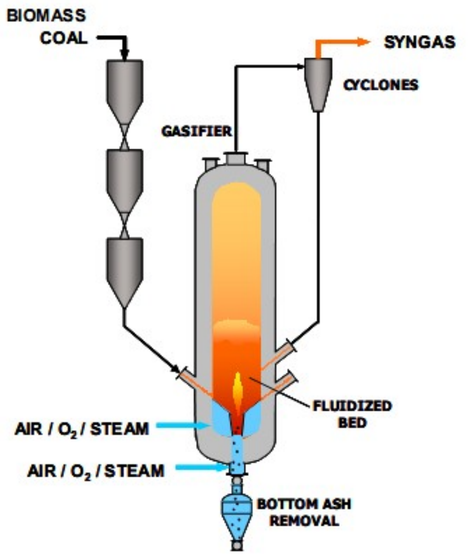
Full commercialisation of pyrolysis is expected in the future and one of the key prospects is the use of pyrolysis gas and pyrolysis oil, following extensive chemical refining, to be used as fuels and non-fuel products, and this approach is expected to become more common in future years, possibly in preference to power generation projects.

Gasification

3.4.3.4 Technology Description

Gasification involves the partial combustion of a feedstock, in conditions of restricted air or oxygen and in the presence of steam to produce a fuel gas rich in methane, carbon monoxide and hydrogen.

Figure 3-10: Gasification Process



Source: http://newenergyandfuel.com

Oxygen-blown gasifiers have been used as part of coal-fired integrated gasification combined cycle demonstration projects, and produce a medium calorific value gas (a mixture mostly of methane, CO, hydrogen and CO_2). Most waste or biomass gasification technologies use air and steam as the gasification atmosphere, and produce a very low calorific value gas (typically 4 to 5 MJ/Nm^3) due to the addition of nitrogen (a dilutant from the feed air) to the fuel gas mixture.

The gasification process produces a gas consisting of hydrogen, carbon monoxide and a range of other non-combustible gases such as nitrogen. The gas has a low CV (typically around 4MJ/kg), a higher CV can be achieved by injecting oxygen (reducing inert N_2 present in air). Injecting steam increases the H_2 content by secondary reactions in the gasifier, known as the water gas shift reaction; this also increases the CV.

Where the fuel gas is to be used in an engine or gas turbine power equipment, it requires extensive clean-up, as with pyrolysis gas. The technology for this cleaning still requires long-term demonstration to prove reliability.

There are a number of gasification technologies that have been developed and these can be grouped into four types based on the configuration of the process equipment as follows:

a. up-draught – fixed bed
b. down-draught – fixed bed
c. entrained-flow, or ‘transport’ reactors
d. fluidised bed (i) atmospheric, or (b) pressurised

Demonstration projects are in use, but may still be considered as non-commercial and awaiting reliable, continuous and long-term operation. Costs per unit of fuel energy output are generally too high to encourage widespread adoption at present, except in niche applications.

Entrained-flow gasifiers are most common in specialised industrial applications and have not been widely proposed for power projects.

Fluidised bed gasifiers can be used for larger biomass projects. They are more tolerant of feedstock properties than the grate-based systems, including up-draught and down-draught reactors, due to turbulent reaction conditions established in the bed.

Circulating fluidised bed gasifiers are commercially available, e.g. from Finnish boiler suppliers, but are not expected to be economically viable except in very large sizes (e.g. >40 MWe) which is generally larger than appropriate for biomass (or waste) projects. A pressurised circulating fluidised bed gasifier was demonstrated, during the 1990s, at Varnamo in Sweden. This was 10 MWe and used wood chip feedstock to give a low calorific value gas which was used in a 5 MWe gas turbine. The system also included a 5 MWe steam turbine (from gas turbine exhaust, and process cooling steam) and a steam-bled wood chip drying stage. The project was discontinued after 3 years when it had achieved its demonstration aims, as it was otherwise uneconomic.

'Plasma gasification' uses high temperatures available from (electrically-powered) plasma torches to provide the heating for gasification but this results in high auxiliary power demand and therefore reduced electrical efficiency. At present this technology has only been demonstrated for hazardarous material disposal rather than as a viable energy generation technology from municipal waste.

Present technologies for waste 'gasification' from companies such as Energos, Cyclamax, and Energy Products of Idaho (EPI), mostly involve only staged combustion where a syngas is produced fleetingly before being immediately burned. As a result, these technologies compare poorly with 'traditional' combustion-type incinerators. They have the same emissions and stack gas clean-up requirements, (with the possible exception of reduced NOx), but lower net electrical efficiency, due to lower pressures of steam produced and increased auxiliary loads.

Waste gasification generally requires pre-treatment of material to give a homogeneous high-CV feedstock and this calls for an additional pre-processing stage and additional auxiliary loads for power generation. However, some 'true' waste gasification systems are under development that would be able to use un-processed municipal solid wastes as a feedstock, but these are still pre-commercial.

3.4.3.5 Explanation of Capex model inputs

An indicative breakdown of a 2MW woodchip gasification based power plant is presented in Table 3.21

Table 3.21: Gasification Capital Cost Breakdown

Item		Wood – Gasification
	Est. cost per kW	Proportion of cost
Consultancy / Design	£258	6%
Civil works	£559	13%
Fuel handling / prep	£245	6%
Electrical / Balance of plant	£172	4%
Converter system (gasifier)	£2,679	62%
Prime mover	£387	9%
Total	**£4,300**	**100%**

Source: Mott MacDonald estimates

The capital cost breakdown shown above picks out the main components of a fixed bed biomass gasifier based on two 1MW modules driving a gas engine and generator. The costs have been built primarily from EPC costs known by Mott MacDonald, where appropriate this has been supplemented by information in the public domain and judgement of our engineers.

The capital cost is currently estimated in the order of £4,300/kW based on the few pre and early commercial stage projects in the UK. Capital cost is likely to fall as proven and reliable models become established but it is difficult to apply a time frame to these developments.

The breakdown of costs is comparable to pyrolysis with the key elements being the converter unit (the gasifier) and associated gas clean-up technologies. In many respects the opportunities for reduction in costs are similar to pyrolysis. Developing cheaper processes for the cleaning and upgrading of gases coupled with improved fuel handling and processing equipment could result in cost reductions. Gasification technology has a wide variety of applications and the demonstration and deployment of these will potentially reduce the costs of installation.

Consultancy / Design

These costs reflect the elements associated with project development, consents and planning. Future reduction in the capital cost is limited with the majority associated with the benefit of increased installed capacity in the UK system and some standardisation of design.

Civils

Cost estimates for the civils components are based on Mott MacDonald's experience. Evolution of these costs is predicted to result in reductions associated with experience from installed plant. As with pyrolysis some material savings and improvements in design are anticipated to result in cost reductions although the benefits are estimated to be comparatively small.

Fuel Handling and Preparation

Fuel handling and processing requirements are potentially significant with the fuel input often requiring sorting, drying, processing and blending. This process is assumed to be automated with some manual handling at the start. The feedstock is assumed to be formed primarily from wood which reduces some of the associated costs in design. To 2020 modest reductions in the capital cost are anticipated which are estimated to be driven from the the supply of consistent fuel and improvement obtained via the experiences from other plant. Beyond 2020 improvements in the handling of fuels are anticipated to continue as the process of fuel sorting and provision is improves significantly.

Electrical and Balance of Plant

These costs cover the equipment necessary for connection of the plant to the grid but does not include the costs of transmission lines. The balance of plant costs include the cost of control and monitoring systems along with other costs that are not easily defined into other categories. Both to 2020 and beyond 2020 the opportunities for cost reductions in this area are considered modest. The systems are relatively mature with some potential savings on the controls associated with syngas treatment as new fuels potentially reduce the need for pre-combustion gas cleanup.

Converter System

The converter system includes the gasification plant and gas collection systems along with the majority of the gas cleaning systems. The costs have been developed from EPC cost estimates that Mott MacDonald hold supplemented by expert judgement for plant of these sizes. The converter system is the standout element of the capital costs. The evolution of costs to 2020 is anticipated to be driven primarily through experiences gained as this technology demonstrates commercial deployment in the UK. In addition the development of the technology in the UK will enable some improvements in the gasification process to occur. Beyond 2020 these improvements are anticipated to continue as the technology matures. It is noted that modular systems are emerging but these remain at small scales. Should these become proven there may be some cost benefits from employing modular construction techniques.

Prime Mover

The prime mover relates to the power generation technologies and includes the converter and any in-line elements such as particulate matter filters etc. Gas engines have been assumed for this component as these represent the most efficient method by which the gas can be converted to electricity (and heat, if appropriate). They are fast to start up and have a good load following ability. There is extensive field experience and numerous models available in the market. Cost reductions over time are likely to be small but may be achieved through a combination of design demonstration and efficiency gain. Additional benefits could arise from lower cost gas engines becoming proven and gaining the reliability recognition that allows better penetration of the UK market.

3.4.3.6 Gasification Conclusions

As is the case with pyrolysis gasification technology is becoming demonstrated in the UK. The technology still requires mainstream commercial demonstration but this will happen in the next five years. Developments in the gasification process for specific fuels may result in cost savings. Application of gasification to other fuels has some potential but some of these combinations will need to demonstrate viability and performance before being able to penetrate the market. Conversion of the syngas is likely to be through gas engines but other options exist including the development of fuel cells. Consideration of the evolution of fuel cells is beyond the scope of this study. The outlook for capital costs is summarised in Table 3.23.

3.4.4 Bubbling Fluidised Bed (BFB) Combustion

3.4.4.1 Technology Description

BFBs are designed to provide a highly turbulent environment for combustion reactions, thereby reducing both combustion temperatures (and associated thermal NOx) and excess air requirements, which then improves thermal boiler efficiency due to reduced stack heat loss. A BFB is very similar to the Circulating Fluidised Bed Boiler (CFB). It differs due to the slower fluidisation velocity of the introduced high pressure air which is fed in through the bottom of the boiler and causes a bubbling effect and allows most of the bed material (normally sand) to be retained in the lower furnace. This type of technology does not have the same level of ability as the circulating technology to retain sorbents due to the lack of a cyclone material recovery stage, and so require greater feed rates to absorb sulphur dioxide or HCl. BFBs are normally used to burn lower-quality fuels with high volatile matter including biomass.

BFBs are a well established commercial technology, used in the scale ranging from a few MW to 100 MWe; we have assumed a 40 MWe scheme.

Figure 3-11: Bubbling Fluidised Bed (BFB)

Source: www.metso.com

BFBs are susceptible to damage through ash fusion. This can be a problem, especially on cereal-based biomass fuels which are high in potassium, so care has to be taken with material proportions in the feed where such problem fuels are used. Use of BFBs for waste combustion has to allow for 'bed drainage' of bottom ash which may contain very large items derived from the input Municipal Solid Waste (MSW). Special designs have been developed and are now operating (e.g. Allington), however, these designs were originally problematical as was the case in Dundee. For this costing analysis we have assumed that the feedstock is wood chips or pellets[20].

[20] The use of other feedstocks will have implications for the feedstock handling and preparation, emission control requirements and potentially plant availability. In general, the impacts will be reduced where the feedstock has a high degree of homogeneity, low

No major technology breakthroughs are expected on biomass firing. However, fluidised beds may become more widely used for sorted MSW, subject to over-coming planning permission restrictions on all incinerators. The total plant capex is currently about £3,800/kW with the boiler forming the majority of the costs. Some cost reduction may be possible through the continued demonstration of this technology and improvements in the fuel handling and processing. Such gains are likely to be relatively limited as is shown in Table 3.23, where a 25% reduction is seen by 2040.

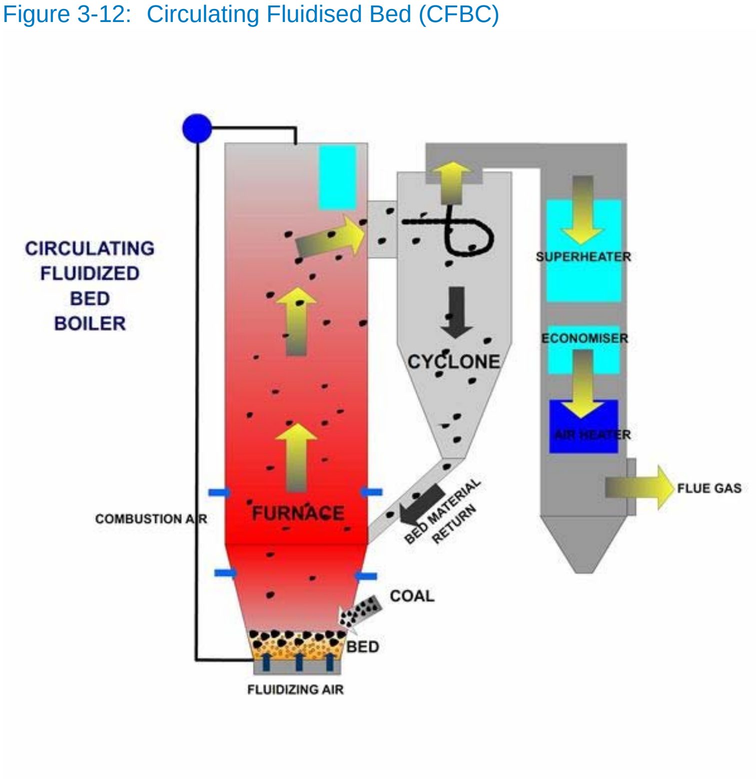
3.4.5 Circulating Fluidised Bed (CFBC) Combustion

3.4.5.1 Technology Description

CFBCs are a development from BFBs and are now well established for applications of large capacity and low volatile fuels, or ones where extensive in-bed sorbent use is needed due to the nature of the fuel. A bed of inert material (normally sand) sits on the bed of the boiler furnace where the fuel spreads. High pressure combustion air is fed into the boiler from the bottom of the furnace, suspending the bed material and fuel particles in the air. Combustion then takes place during suspension.

Fine particles of the partly burned fuel and bed material rise up to the top of the furnace along with the flue gas into the attached cyclone. The heavy particles e.g. the bed material, separate from the gas and fall to the cyclone hopper. These particles are then returned to the furnace to be used again. The hot gases that remain in the cyclone are then passed to the heat transfer surfaces and out of the boiler. CFBCs achieve more efficient use of sorbent than BFBs, due to longer residence time.

Figure 3-12: Circulating Fluidised Bed (CFBC)



moisture and narrow size range.

Source: www.coalpowerplant.us

CFBCs are susceptible to damage through ash fusion, which can be a problem especially on cereal-based biomass fuels (which are high in potassium) so care has to be taken with material proportions in the feed where such problem fuels are used.

CFBC systems are not usually considered below ~30 MWe and an upper limit for single units at present is 450 MWe (coal-fired) or 300 MWe (100% biomass-fired). They are the technology of choice for large combustion projects on fossil fuels or biomass due to superior environmental performance without any significant increases in capex or opex compared to pulverised fuel-fired systems

It is expected that CFBCs will achieve wider use on large projects worldwide, displacing or supplementing existing pulverised fuel technology on fossil fuels. In terms of unit size, the equipment has probably reached a limit. This is especially true for biomass which would require extensive infrastructure to transport enough fuel for 300 MWe projects (such as proposed by Drax Power). More use of smaller capacities, up to 100 MWe, may be more appropriate. For the purposes of modelling we have assumed one unit sized at 150 MWe with a woodchip/ pellet feedstock.

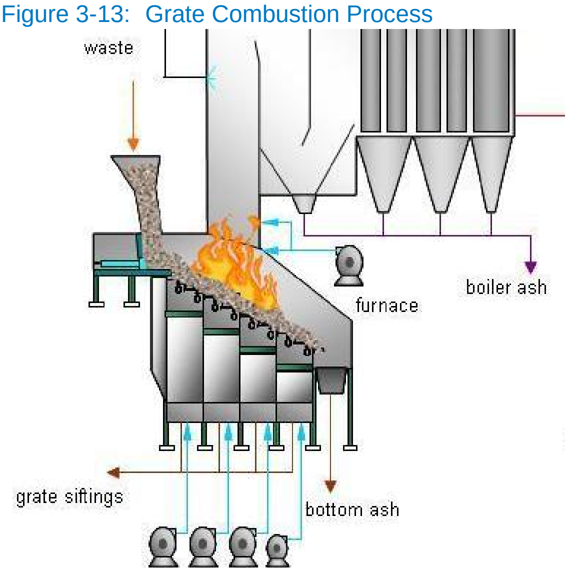
The approximate capital costs of CFBC are in the order of £2,178/kW noting that there are significant economies of scale with the size of the plants in the hundreds of MW. In terms of cost savings the situation is similar to BFB boilers with the majority of the capital costs focused on the boiler system. Looking forward, the same drivers apply as with the bubbling bed technology, and so we are projecting a similar cost reduction over time – see Table 3.17.

3.4.6 Grate Combustion

3.4.6.1 Technology Description

Grate combustion is the use of a grate to enable the slow movement of fuels through the boiler furnace. Combustion of feedstocks on a moving grate is suitable for projects from 1 to 30 MWe unit sizes. It is an old and well established technology, which is suitable for biomass firing.

Figure 3-13: Grate Combustion Process



Source: www.winderickx.pl

Higher excess air is present during grate combustion than for Circulating Fluidised Beds (CFBs) and Bubbling Fluidised Beds (BFBs). This, combined with its lower burn-out efficiency, results in a lower overall thermal efficiency. The advantage of grate technology over CFBs and BFBs is that Grate Combustion technology is not damaged by ash fusion and can therefore be used for problem biomass fuels such as straw. A common design, for a large number of projects now in China for example, uses a sloping vibrating grate for combustion of wheat straw or rice straw at 25 MWe unit size. However, post-combustion clean-up is still required for acid gases, and particulates.

Whenever a waste incinerator is proposed, major public opposition is inspired by Grate Combustion technology due to the perceived health impacts from stack gas emissions, although in practise, the actual emissions are normally well within EU limits on such processes. Public opposition has been a significant barrier to growth of this technology.

As noted above, Grate Combustion is an old and well established technology and so no major technical developments are expected. Costs vary depending on size with cost reductions with scale being quite significant; for example, from approximately £3,000/kW for ~ 30MW plants through to approximately £2,100/kW for a ~150MW unit. In our analysis we have considered 10MW and 40MW grate plants fired on wood chips and waste wood, respectively.

3.4.6.2 Explanation of Capex model inputs

The biomass combustion options considered in this study alongside the respective total indicative capex costs are summarised in Table 3.22.

Table 3.22: Biomass Combustion Capital Cost Breakdown

Item	Wood- Grate		Wood – BFBC		Wood - CFBC		Waste Wood - Grate	
	Est. cost per kW	Proportion of cost	Est. cost per kW	Proportion of cost	Est. cost per kW	Proportion of cost	Est. cost per kW	Proportion of cost
Consultancy / Design	£335	10%	£526	14%	£299	14%	£595	19%
Civils	£436	13%	£550	14%	£313	14%	£432	14%
Fuel handling / preparation	£402	12%	£407	11%	£232	11%	£427	13%
Electrical / Balance of plant	£235	7%	£409	11%	£233	11%	£307	10%
Converter system	£1,675	50%	£1,640	43%	£933	43%	£1,281	40%
Prime mover	£268	8%	£295	8%	£168	8%	£147	5%
Total	£3,350	100%	£3,828	100%	£2,178	100%	£3,190	100%

Source: Mott MacDonald estimates

The capital cost breakdown shown above picks out the main components of biomass schemes. The costs have been built primarily from EPC costs known by Mott MacDonald, where appropriate this has been supplemented by information in the public domain and judgement of our engineers.

Consultancy / Design

These costs reflect the elements associated with project development, consents and planning. Future reduction in the capital cost is limited with the majority associated with the benefit of increased installed capacity in the UK system and some standardisation of design. The combustion of waste wood results in an increased consultancy/design costs in order to respond to regulatory and public pressures.

Civil works

Cost estimates for the civils components are based on Mott MacDonald's experience. Evolution of these costs is predicted to result in reductions associated with experience from installed plant. Some material savings and improvements in design are anticipated to result in cost reductions although the benefits are estimated to be comparatively small.

Fuel Handling and Preparation

Fuel handling and preparation is an important process for biomass plant. This process is automated and the quantity of fuel is significant especially for the larger plant. In relation to the BFB and CFB technologies the preparation of the fuel is more significant and some cost reductions may be possible as such plant become more common. To 2020 modest reductions in the capital cost are anticipated which are estimated to be driven from the supply of consistent fuel and improvement obtained via the experiences from other plant. Beyond 2020 improvements in the handling of fuels are anticipated to continue as the process of fuel sorting and provision is improves significantly.

Electrical and Balance of Plant

These costs cover the equipment necessary for connection of the plant to the grid but does not include the costs of transmission lines. The balance of plant costs include the cost of control and monitoring systems along with other costs that are not easily defined into other categories. Both to 2020 and beyond 2020 the opportunities for cost reductions in this area are considered modest/small.

Converter System

The converter system comprises the majority of the capital costs for CFB and BFB technologies. The costs have been developed from EPC cost estimates that Mott MacDonald hold supplemented by expert judgement for plant of these sizes. The evolution of costs to 2020 are anticipated to be driven primarily through experiences gained as this technology demonstrates commercial deployment in the UK. In addition the development of the technology with biomass fuels may help improve issues with reliability (which links back to fuel preparation for CFC and BFB. There are economies of scale to be gained from larger units although the overall size of these plants will be limited due to fuel supply constraints. Economic locations for the development of larger biomass plant will be limited and therefore longer term opportunities for new larger plant may in turn be limited. Beyond 2020 developments are anticipated to continue as the technology matures which will lead to cost reductions.

Prime Mover

The prime mover relates to the power generation technologies and includes the converter and any in-line elements such as particulate matter filters etc. Steam turbines have been assumed for this component as these represent the most efficient method to convert the heat to electricity. They have high reliability and a long life. There is extensive field experience and numerous models available in the market. Cost reductions over time are likely to be small but may be achieved through a combination of design demonstration and efficiency gain.

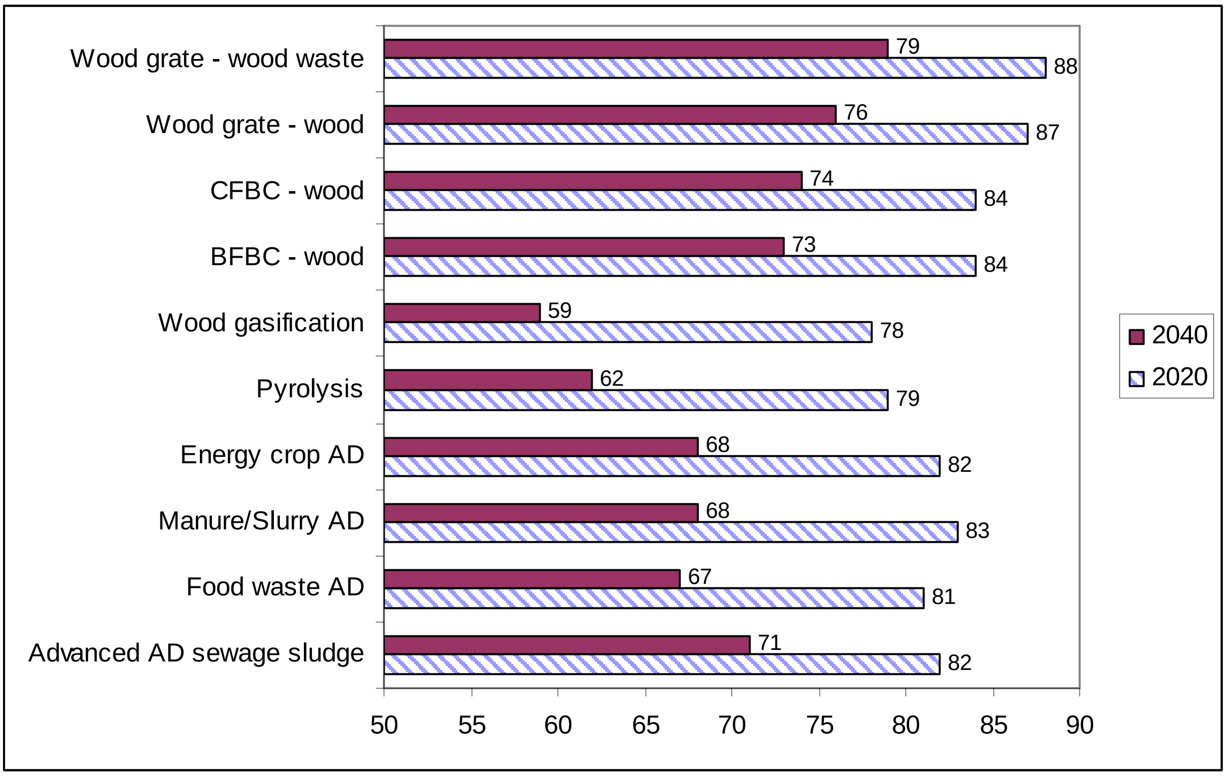
3.4.6.3 Biomass Combustion Conclusions

These are mature technologies and are generally bankable if fuel supply issues can be resolved. The grate systems are the most established and are known to work/are flexible with fuels. CBF and BFB require more processing but provide the potential to attain greater capacities. As noted above the key to the development of these technologies is the availability and reliability of suitable feedstocks.

3.4.7 Summary on biomass technology capital cost developments

Figure 3.14 and Table 3.23 show the projected development of installed capital costs across the 10 selected biomass technologies considered in this study under the MML central case assessment. Although biomass fired generation technologies are not perceived to be undergoing dramatic technological change or cost reductions through scale up compared to solar and wind, we still see significant cost reductions across all technologies through to 2040. The greatest reduction is projected for advanced gasification and pyrolysis, the technologies at earliest stage of deployment, with reductions on 2011 by 2020 and 2040 of 41% and 38%, respectively. At the other end of the scale are the fixed bed boiler technologies (using grates and firing solid wood) which see comparatively modest improvements of about 20% by 2040. The AD technologies are expected to achieve reductions in the middle range, of 30-34%. In all most cases, the main components seeing the cost reductions are the fuel converter systems and the fuel handling and preparation. Projected savings on the prime mover are less as these technologies are well established. Civil, electrical and balance of plant is similarly expected to see modest reductions, expect where there is a major change in a components characteristics or the system integration is altered, only really possibilities for gasification and pyrolysis.

Figure 3.14: Projected capital costs in 2020 and 2040 as % of 2011 level



Source: Mott MacDonald estimates

Table 3.23: Projected installed capital cost in 2020 and 2040 under MML central case

	Capex cost as share of 2010/11 level		Projected installed capital cost: £/kW	
	2020	2040	2020	2040
Advanced AD sewage sludge	82	71	2137	1847
Food waste AD	81	67	5928	4842
Manure/Slurry AD	83	68	4217	3488
Energy crop AD	82	68	5569	4517
Pyrolysis	79	62	2450	1945
Wood gasification	78	59	3349	2551
BFBC – wood	84	73	3210	2798
CFBC – wood	84	74	1824	1615
Wood grate – wood	87	76	2917	2621
Wood grate - wood waste	88	79	2815	2524

Source: Mott MacDonald estimates

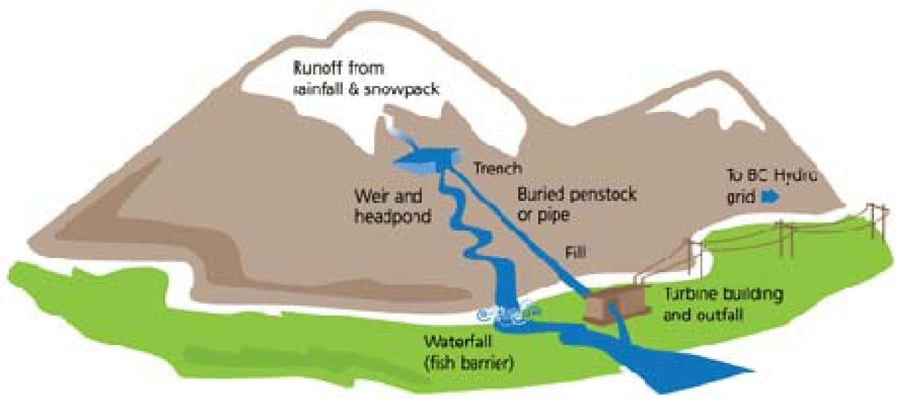
Outlook for levelised costs

Taking the above capital cost assessments, our central case projections for other plant cost and performance parameters and Oxera's central discount rate case (both outlined in Chapter 6) gives an indicative current range of levelised cost of £51-171/MWh across the range of biomass technologies. Advanced AD on sewage sludge is the lowest cost while AD on energy crops is the most expensive. Most of the other biomass technologies, except pyrolysis of municipal wastes are above £100/MWh. These costs include any market congestion premium on the capex, however this is small in the case of all the technologies here. 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 gives a levelised cost in 2020 and 2040 of £43-149/MWh and £32-129/MWh, respectively. The ranking of technologies remain broadly the same as currently. These ranges only consider capex uncertainty. 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.

3.5 Run of river hydropower

Run of river hydropower (Hydro RoR) is the process of capturing kinetic energy produced from the natural down stream flow of rivers without damming the flow. Run of river schemes work by diverting a portion of a river's flow down a channel and through a water turbine before being returned back to the river. Run of river schemes are often more favourable than larger hydropower schemes that use dams because of the environmental issues associated with both the construction of dams and the subsequent flooding of large areas of land.

Figure 3-15: Diagram of a typical Hydro ROR scheme



Source: http://jagadees.wordpress.com

Historically, planning constraints combined with a lack of financial incentives have meant that there has been a relatively small installed capacity of Hydro ROR installed in the UK, estimated at approx100 MW. The UK government has introduced incentive schemes including the Feed In Tariff (FITs), which are expected to stimulate an uptake in Hydro RoR.

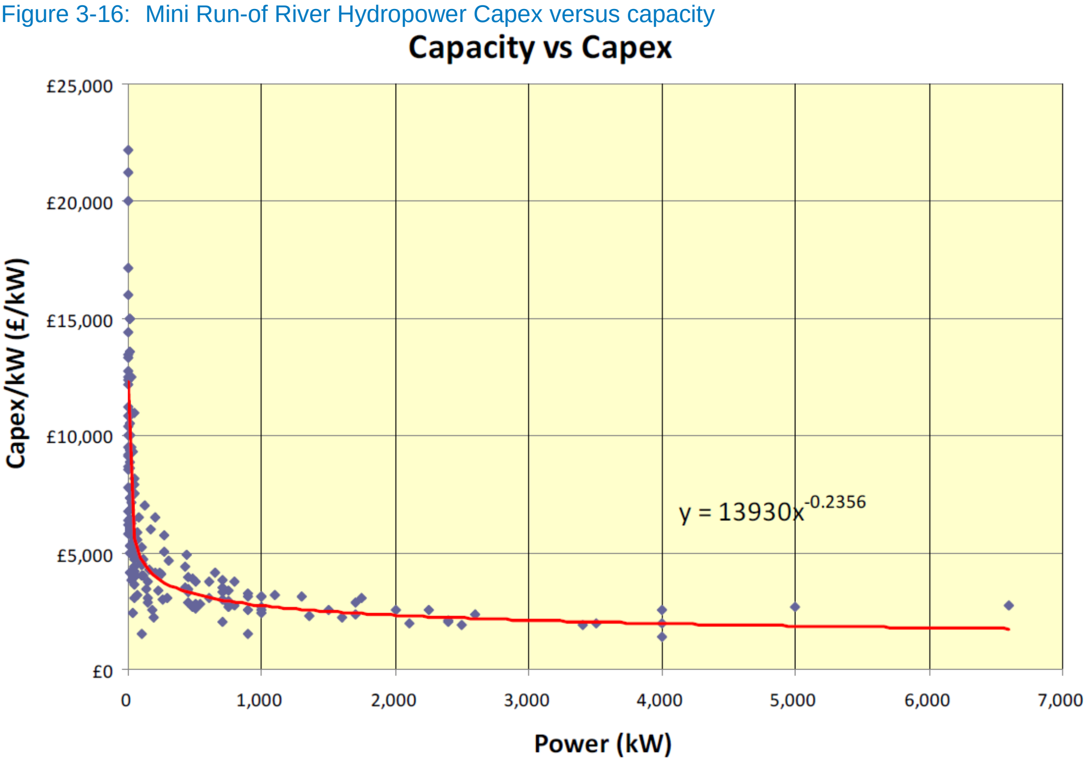
It is estimated that there is useable resource in the UK for a maximum installed capacity of between 300 – 600 MW. However, the viability of such schemes is dependant on future planning conditions, and the commercial case, based on the FIT or RO rates, which are revised periodically.

Hydro-turbines are a well established technology with a long commercial track record and no substantial future developments are expected in the design of Hydro ROR schemes themselves. However, adaptation of the schemes to include storage could improve efficiency and allow the use of up to 90% of the water resource for generation compared to the 50% which is typical of current Hydro ROR schemes. These conversions could be by way of bolted on storage or the use of existing reservoirs. The addition of pumped storage may also be a way of improving existing schemes in the future.

There are only a few established UK based providers of Hydro ROR plant and with relatively little competition between providers, the current cost of RoR plant is considered relatively high. Civil works costs vary depending upon a particular scheme. The supply cost of plastic pipelines and fuel for civils is subject to fluctuations in oil prices (for example the cost of plastic pipes is estimated to have increased by as much as 15 – 20% during late 2010 and early 2011 due to oil price fluctuation). Future rises in oil prices may therefore have a direct effect on the capital cost of Hydro ROR schemes. Gilkes, who are the largest manufacturer of hydro turbines and associated equipment in the UK, have produced an estimated cost curve for run of river schemes based on actual schemes constructed in the UK. The curve fits the following formula:

$$\text{Capital Cost} = 13930\ (\text{Capacity in kW})^{-0.2356}$$

Figure 3-16: Mini Run-of River Hydropower Capex versus capacity



Source: Gilkes, The Feed In Tariff - The consultation story and opportunities for the hydro industry

Mott MacDonald has reviewed the Gilkes' equation against its own project experience and found it to be a reasonable representation of recorded Capex figures (+/- 20%). In general, capital cost (£/kW) of a Hydro RoR scheme decrease exponentially as the capacity of the scheme increases. Capital cost is around £2,000 – £2,500/kW installed for a typical scheme between 1MW and 5MW. This cost is not likely to change much in the near future unless the schemes are adapted for storage.

O&M cost is currently estimated at 3% of capital cost but can vary depending upon the scheme size, profile location and the number of schemes being serviced (known as clustering).

Provided that government incentives stay in place and planning constraints do not differ greatly, Hydro ROR schemes will remain a proven and reliable technology that are likely to see reductions in capital cost due to increased competition between equipment suppliers.

Indicative levelised costs for mini hydro (2MW), on the basis of an annual capacity factor of 45%, are currently £69/MWh, based on Oxera's central discount rate assumption. Looking forward, under the MML capex assessments and using the central case discount rate projection gives a levelised cost range in 2020 and 2040 of £63-67/MWh and £52-58/MWh, respectively. Only a limited cost reduction is expected from capital cost reductions.

3.6 Tidal barrage

Tidal barrage schemes are a technology that has attracted interest in the UK for several decades given the UK's high tidal range and number of estuaries where such schemes could be deployed. However, while there is evidence that the technology can be made to work reliably, as the Rance Estuary scheme in northern France has demonstrated there is considerable uncertainty about the costs in a modern UK context. These costs comprise the direct costs of the massive civil works and the mechanical and electrical equipment but also the indirect costs of habitat compensation, which for some locations and scheme designs can be the same order of magnitude as the direct costs.

Below we briefly outline the technology options, then consider current cost drivers and indicative costs and finally comment on future developments.

3.6.1 Technology description

Tidal range technologies utilise a solid structure to impound water at a high level, and release it back to the main body of water at a lower level. This can be accomplished whenever there is a change in water level, and so energy can be extracted on both the ebb (outbound) and flood (inbound) tides, although flood generation typically has lower capacity for generation. The energy potential of any tidal range scheme is fundamentally dependent on the difference between high and low tide, otherwise known as the tidal range, the amount of water that flows past the impounding structure and the area of the impoundment or basin area.

There are two slightly different approaches to providing this impoundment structure; tidal barrage and tidal lagoon.

The basic constituent elements of a tidal barrage are; caissons, embankments, sluices, ship locks and turbines. The sluices, turbines, and ship locks are housed in caissons, which are effectively very large concrete blocks that act to impound the water. The role of the embankments is to seal the basin where it is not sealed by the caissons themselves. Sluices are the gates in the structure which allow the water to flow in ebb and flood directions. Ship locks are crucial to allow the transit of marine vessels through that body of water and need to be sized accordingly to suit the vessel size. For the low-heads and high flows required in tidal barrage schemes the turbines employed are axial-flow turbines; like ships propellers, located within an enclosed duct. They are related to hydro turbines, but certainly are not interchangeable.

The basic premise of operation for tidal barrage schemes is relatively simple. Acting in the simplest mode of generation, the water is allowed through sluices in the barrage in the flood direction. The water level in the estuary then rises. The sluices are closed and the tide begins to ebb. When the water level outside the barrage has fallen sufficiently the turbines are opened, and water in the estuary is released back to the sea generating electricity. This is called ebb generation. There are variations on the mode of generation, in which generation is on the flood cycle, or else a dual operation.

Tidal lagoon schemes adopt a similar principal to tidal barrage schemes in that they comprise a solid structure that is used to impound water which is then released through turbines leading to generation of electrical power. The difference is that they impound only part of the water in the channel in contrast to tidal barrage schemes which span the entire width of a channel. Although, proposals have been made for Swansea Bay and the Severn Estuary, no tidal lagoon schemes have been constructed to date. It is envisaged that tidal lagoons can be configured in two ways; either as land-connected lagoons or as stand-alone structures which are isolated in the middle of the basin.

Tidal reefs are in principle tidal impoundment barrages that operate with a low head. They are intended to operate on a lower head differential, with the objective of limiting impact on the natural tidal cycle compared with a conventional barrage to minimise the environmental impact. Tidal reefs require a less sophisticated civil works, but the turbines are less proven than conventional barrage turbines and hence there is greater uncertainty of operational characteristics. Again, there is no track record of tidal reefs.

3.6.2 Cost drivers and current indicative cost estimates

The nature of tidal barrage schemes is that they are designed for a certain location, and as such the cost build up will depend on the site and design configuration. Invariably, in terms of the direct scheme costs, the major items will be the civil works; the barrage itself. These civil costs clearly comprise a significant element for materials (cement and building aggregates, steel, etc) but tend to be dominated by on-site labour and supervision and construction equipment and services. After civils, the next biggest item is normally the turbine equipment. Given the maximum rating of these machines (rarely larger than 200MW) and the high capacity of some of planned schemes (up to 8GW in the case of the Cardiff-Weston Severn scheme), there is often a requirement for tens of turbines. The third largest direct cost item is the electrical connection to the main grid. This is ignoring any potential requirement for deeper grid reinforcement, which is excluded in this analysis (as it is for generation types).

Given that most tidal barrage schemes will lead to substantial changes in the local habitats, most notably loss of wetlands, there is normally a requirement on scheme designers to carryout additional civil works to provide habitat compensation. Clearly, this requirement can be reduced through mitigation measures in terms of scheme design and/or operation that would reduce the detrimental impacts, however these mitigation measures often increase capital costs and/or reduced energy production, so offsetting the gains on the compensation account. For the largest schemes under considerations, such as on the Seven, these compensation costs are several £bn, and they become the second largest item after the civil works.

The latest capital cost for the Severn tidal schemes[21] and other seen by MML for Solway, Mersey and elsewhere indicate that the specific capex costs can be comparable with other low carbon generation at £2800-4000/kW for larger schemes. Some of these estimates exclude optimism bias, which the government often adds as a contingency in carrying out cost-benefit appraisals. It is also unclear whether they include the full habitat compensation costs. Capital costs are very dependent on site conditions and to a lesser extent the scheme design (barrage versus lagoon, and generation cycle). For this analysis we have estimated costs for a hypothetical 2GW tidal barrage scheme on a west coast estuary. Table 3.24 shows our indicative capital cost build up for a large hypothetical 2GW tidal barrage scheme on a UK west

[21] Severn Tidal Power, feasibility study conclusions and summary report, PB Power, October 2010.

coast estuary. This shows a total installed cost of £3300/kW, of which just over half are civil works. This total excludes habitat compensation costs on the grounds that the scheme is designed and would operate to mitigate these impacts. Likewise optimism bias is excluded in order to ensure consistency with other technologies considered in this study.

Table 3.24: Indicative current capital cost build up for a large tidal barrage scheme (2 GW)

	Base price: £/kW	% share of total
Site prep/ licensing	400	12%
Turbines	900	27%
Civil works	1750	53%
Electrical works	100	3%
BoP	150	5%
Total	3300	100%

Source: Mott MacDonald

While the capacity costs may not appear exceptional, tidal barrage schemes tend to have a comparatively low annual capacity factor, typically in the 15-18% range. This is limited by tidal patterns and there is no scope to increase this (except through a pumping cycle, which is not considered further here). Operating costs are low as percentage of capital costs – comparable to hydropower. We have assumed that there are no operational habitat compensation costs.

3.6.3 Future costs developments for tidal barrages

There is little indication of any significant developments that would allow tidal barrage schemes to be carried out at significantly lower costs to those currently envisaged. It is possible that innovations in turbine production techniques could in the long term reduce turbine costs, however, it is difficult to see how the costs of building caissons, embankments, sluices etc will be substantially reduced. On the other hand, the habitat and other compensation costs may increase as estuarine and coastal areas are further developed.

Our central case projection sees an 8% reduction in real capital costs by 2040, with the turbine costs seeing the largest decrease. This is the smallest reduction of any of the renewable technologies and reflects the limited scope for learning and technical innovation.

Indicative levelised costs

Indicative levelised costs for tidal barrage schemes, on the basis of an annual capacity factor of 17% would be currently over £500/MWh, based on Oxera's central discount rate assumption of 14.5%. Looking forward, under the MML capex assessments and using the central case discount rate projection (12.9% and 10.2% in 2020 and 2040) gives a levelised cost range of £403-439/MWh and £271-312/MWh, in 2020 and 2040 respectively. Much of the cost improvement reflects the discount rate reduction, rather than capital cost reduction. Actual project costs will vary considerably around this and may be significantly influenced by habitat compensation costs, which are assumed to zero here through appropriate mitigation measures built into the design and operational modes.

3.7 Wave and Tidal Stream

3.7.1 Introduction

Wave and tidal stream power generation technologies are at a very early stage of development with no commercial scale deployment. The largest devices are at a few MW scale, in most cases they are under 1 MW, one or two scale stages below the expected scale of deployment. UK installed capacity in January 2010 was 0.85 MW wave and 1.55MW tidal stream (Renewables UK 'state of the industry report', March 2010). In addition, the operating experience of most of the tested devices has shown that the marine environment is more challenging than the designers had expected. However, the considerable promise of low variable cost carbon free energy in the UK's offshore has and is still attracting considerable interest and there is a widely held view that wave and tidal stream could together deliver 10-30 TWh a year by 2040.

There are many differential devices under development worldwide for both wave and tidal stream generators, with different design philosophies. It is not the remit of this study to assess the viability and cost outlook of these particular devices, instead we have commented on the generic cost drivers and the necessary preconditions for the successful application of three types of devices – shore based fixed wave generators, floating wave generators and tidal stream generators.

Marine devices need to contend with marine growth; sand abrasion; extreme wave and tidal turbulence; and salt. This is all the more challenging if the prime mover is submerged below the water, which of course it is not for wind.

Floating wave devices have the advantage versus tidal stream (and offshore wind) of avoiding the need for foundations, although they still require significant cost in tethering arrays and longer cabling distances, since they will be located potentially a long way offshore. Our view is that a robust first generation floating wave device is going to cost somewhere between £3500-4500/kW.

Tidal stream costs would be expected to have a lower specific capex cost, given the higher energy density, assuming that a low cost foundation and installation techniques can be used. On this basis the first generation full scale tidal stream device could have a specific capex of £3500-4500/kW. While there is no data yet available, our view is that tidal stream devices should achieve a much higher annual capacity factor than wave devices, about 35-40% assuming that they are located in the best sites (Pentland Firth, being considered one of the best) versus about 20% for wave. This has yet to be confirmed and some recent modelling studies indicate a much smaller advantage for tidal stream versus wave. If this significant differential is confirmed it will clearly have major implications for the levelised costs of electricity from these schemes; a point picked up later.

The implication is that tidal stream appears a move promising technology than floating wave devices. This largely reflects the much higher energy harvesting rate for tidal versus wave, which is inherently more difficult to exploit.

It should be noted as a disclaimer that although there are a lot of aspirations for marine renewable generation to contribute to the UK's energy mix, the industry is still very much in its infancy and is not currently at a state of commercial availability[22]. As the industry is at such an early stage of development there are a number of technology concepts developing side by side. It is hoped that in time the marine

[22] Marine Renewable Energy: State of the industry report. Produced by Renewable UK in association with Entec. March 2010

energy industry will consolidate and development efforts will become focussed only on those most promising options and thus accelerate the rate of learning. Estimates for future capital costs are highly speculative as not only are they dependant upon the specific requirements of wave device design (which is highly variable between concepts) but also on the learning curve of the industry overall, which will be reliant on demonstration projects being implemented. Demonstration plants will only go ahead if the various enabling mechanisms allow.

Renewables UK (RUK) has reported an industry ambition of deploying a combined capacity of 1-2GW of wave and tidal stream by 2020. This looks challenging, given the scale and pace of current demonstration projects. RUK also reports a study by Carbon Trust that shows a rapid fall in levelised costs (75%) as the industry moves from 1MW to 1000MW. While there is the prospect of some learning as capacity is rolled out, the evidence from the offshore wind sector is that it is likely to be initially at a much lower rate of improvement. The emphasis in the first stage will be getting the technology to work reliably.

Once the initial de-snagging stage is completed, it would seem reasonable to apply the learning rates observed in the literature. RUK says a learning rate of 10-15% per doubling could be expected. The issue is what is the appropriate starting point for calculating the doublings. If we apply a 100MW level then moving to 1000MW gives just over 3 doublings and a cost reduction of 25-40%, while if a 10MW start was assumed the reduction would 50-65%. In practical engineering terms, even the more modest 25-40% reduction looks aggressive, by the first 1000MW, unless there is a rapid consolidation around a few devices.

In the longer term there is certainly scope for cost reductions in wave and tidal stream and in principle tidal stream costs could be comparable with offshore wind. Achieving these costs for floating wave may be more difficult given its lower energy density, greater exposure to weather hazard, further distance offshore and a lower annual capacity factor.

In summary the main preconditions for success in this arena are:
- Devices (including the array structures) will need to be very robust – which probably means few mechanical parts;
- They will also need to be designed/located so as to minimise weed and other sand bar risks and/or also allow easy access/ retrieval of equipment for services in order to achieve high availabilities;
- Equipment costs will be aided by having low material input per kW, modular design in order to enable mass production in a control assembly site;
- It should be designed to be easily deployed, for instance “dropped” on seabed, anchored to a secure hub.

Fixed wave devices, which can be designed into a breakwater or sea-wall structures, have an advantage in that one only need consider incremental costs, reconfiguring the civil design and adding the mechanical and electrical plant. They also have the advantage of avoiding undersea cable connections. This suggests a capital cost considerably below that for floating wave and tidal stream devices. A lower energy density and capacity factor would partly offset these devices’ capex advantage, such that the levelised cost might be expected to be just a little lower than for tidal stream devices.

3.7.2 Wave Floating (hypothetical)

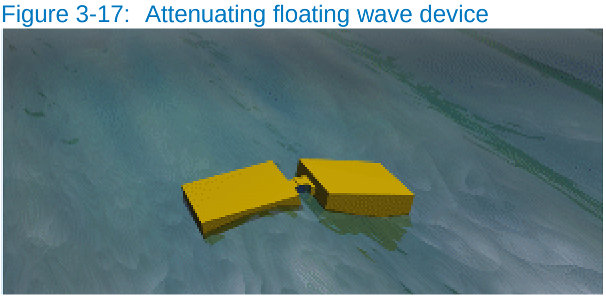
A brief description is given of what floating wave energy is and how it would be harnessed in the UK. Key features of a generic floating wave device that would be suitable for the UK are defined and these form the basis of our 'representative case', which is used to build up the capital cost model. The key assumptions used for the cost model are then described.

Key sources of information have included public domain web-based sources including reports by the Carbon trust, Renewables UK and DECC that present an appraisal of the capital cost of marine renewables.

3.7.2.1 Technology description

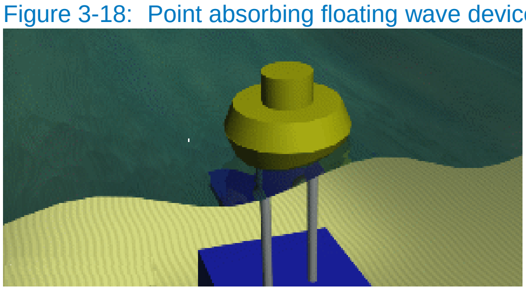
A floating wave device is the term used to describe devices that are placed offshore and float on the surface of the sea where they generate electricity. There are several concepts that fit the description of 'floating wave devices' and two of those that have reached the furthest stage of development and testing are the attenuating device and the point absorber as illustrated in Figure 3-17 and Figure 3-18. A detailed description of how these technologies function is available on the European Marine Energy Council's website http://www.bwea.com/marine/devices.html.

Figure 3-17: Attenuating floating wave device



Source: EMEC

Figure 3-18: Point absorbing floating wave device



Source: EMEC

Floating wave devices are typically located several miles offshore and are anchored to the sea-bed via moorings or foundations depending upon the concept design.

3.7.2.2 Defining a representative plant for Capex estimate

There is no data available for the capital cost of an installed commercially viable floating wave device because the technology has not yet developed to that stage. In addition, it would not be sensible to use the cost data from existing prototype and pilot projects upon which to base learning curve projections as it is understood that these current projects would be disproportionately expensive (currently estimated at £10 million / MW[23]). It is therefore necessary to define a hypothetical cost for a commercially available technology at some point in the future assuming that all of the enabling actions have been put in place.

A 1 MW device has been chosen as a representative scale of installation and it is assumed that the device is operating 25km offshore where the depth is 20m. These figures are based upon typical figures for offshore wind turbines and consistent with a study recently performed by MML in its advisory role for Renewable Energy Technology Development. The device is assumed to be anchored to the seabed via moorings or foundations depending upon the concept design. In order to keep the results generic, it has been assumed that the cost of moorings/foundations will be similar to that for an offshore wind farm on a £/MW basis and it is fair to assume this because even though the foundations for floating devices would not

[23] "The Next Steps for Marine Energy – Action Plan" published by Renewables UK (March 2010)

need to be as strong as for offshore wind turbines, the capacity of each device is likely to be lower than the 3-5 MW offshore wind turbines and so the cost per MW is likely to be in the same range.

The hypothetical capital cost of the installation is £ 4,040 / kW which is an estimate based upon the results of a survey performed in a study for the Marine Energy Group (reference) for a project that would be commercially available in 2014. The capital cost estimate is supported by the cost of the demonstration project for the Pelamis floating wave energy device in Portugal, which was reported to have cost £3,226 / kW[24]. The £4,040 / kW figure assumes that all enabling measures have been put in place to allow the industry to develop to a commercial state by 2014.

3.7.2.3 Explanation of Capex model inputs

The estimated breakdown of capital cost for floating wave power is shown in Table 3.31.

Table 3.25: Breakdown of capital cost for a floating wave energy device

Item	Estimated Cost per kW	Proportion of cost
Development and Planning	£440	11%
Prime mover	£2,000	50%
Foundations / moorings	£700	17%
Electrical grid connection	£660	16%
BoP (including assessment and demonstration)	£240	6%
Total	£4,040	100%

Source: Adapted from MEG supply chain results table (reference)

Development and Planning - £ 440 per kW (or 11% of total Capex)

The figure of £400/kW for development and planning was quoted by DECC in its 2009 report[25] on the cost of offshore wind energy. Although no explanation of what exactly was included, the figure is consistent with Mott MacDonald's experience of the likely cost for securing project finance, which includes all the development necessary before a project can begin construction including environmental impact assessments, yield estimates, design, tendering and contract negotiation. It has been recognised that the costs associated with achieving project finance are likely to be more onerous for an unproven technology such as floating wave energy than for offshore wind so an additional 10% has been added to bring the total estimate to £ 440/kW.

It is expected that up to 2020, the cost of project development is likely to fall as lenders begin to get comfortable with the commercial risks and project finance becomes a viable option. In addition, the reliability of energy yields is likely to increase as experience is built up of wave power generation and the cost of yield forecasting is expected to reduce.

Post 2020, there is likely to be a reduction in the availability of good sites as there will be a large number of offshore wind farms by that time. A modest 5% increase in the cost of project development has been assumed.

[24] Marine Renewable Energy: State of the industry report. Produced by Renewable UK in association with Entec. March 2010

[25] From DECC report '*Cost of and financial support for offshore wind'* report number URN 09D/534 published April 2009

Prime Mover – £2,000 per kW (or 50% of total Capex)

Prime mover cost includes the cost of the mechanical plant, electrical generation plant and the cost of the structure upon which they are mounted. The cost also includes the proportionate share of vessels, port charges and other shared costs.

There is not expected to be much of a change in the cost of the prime mover between now and 2020. This is because there are likely to be few competitors in this emerging market and production is unlikely to be on such a scale as to offer mass production and supply chain savings.

We have assumed a 5% reduction in materials post 2020 as a preferred concept becomes apparent and R&D efforts are focused on improving the performance and material intensity (as has been seen in the offshore wind industry). Savings of 10% have been assumed as a result of new market entrants and a more established supply chain giving increased competition and driving down production costs.

Foundations / moorings - £700 per kW (or 17% of total Capex)

A floating wave device implies that the design would be anchored to the sea-bed via some manner of foundation or mooring. The best estimation for the cost of foundations is based upon the equivalent capacity of offshore wind, which typically implies a foundation / mooring cost of £1.4 million per location[26]. The early offshore wind turbines were typically 2 MW in capacity and it has been assumed that a single foundation will similarly support 2 MW floating wave device; thus foundation cost is £700/kW. Whilst moorings are likely to be less costly than offshore foundations, they are expected to be associated with smaller capacity devices than would be attached to permanent foundations and so we have assumed a standard cost of £700 / kW.

Foundation / mooring costs include manufacturing the structure (potentially including large quantities of steel and concrete) thus a high material intensity of 20% has been assumed for the capital model.

The cost of foundations / moorings also includes transportation and installation costs plus a share of the support vessels and harbour facilities. Offshore wave projects will likely be competing against offshore wind for many of these services and as offshore wind is better established, foundation supply companies are likely to favour offshore wind for lower commercial risks. The net affect of mass production cost savings in addition to wave energy being a less favourable market for foundation suppliers is that there is little change expected in foundation cost by 2020.

It has been assumed that post 2020, the material intensity can be reduced by 10% as foundation / mooring design becomes tailored to wave energy devices and benefits are felt from learning from the predicted growth of the offshore wind industry. Material costs themselves have been assumed to increase 10% in the base case model as the carbon intensive production of steel and concrete is likely to incur greater costs as it comes under increasing pressure to reduce emissions.

By 2020 it is expected that there will be more installation and support vessels available than there are today and that there will be more companies offering foundation / mooring construction services so a cost saving of 10% has been assumed.

[26] MML internal database of offshore wind energy projects

Electrical grid connection - £660 per kW (or 16% of total Capex)

The cost of electrical infrastructure was estimated by DECC (with support for Ernst and Young) in its 2009 report[27] as £600 per kW but it is likely that the size of a wave installation will not have the same capacity as a typical wind farm (several hundred MW) and so the fixed costs of electrical connection will not be spread as far for wave energy. An additional 10% has been added to account for the likely increase in the cost per kW.

Material intensity has been calculated at 20% for the total electrical scope of works. The MML internal database shows that around 60% of the total electrical Capex is associated installation activities and 40% for supply. Of the supply portion, it has been estimated that half is associated directly with the material cost as large volumes of copper are used in the multi-kilometre electrical connection to shore.

Post 2020, it has been assumed that the cost of connection to shore will increase by 10% as much of the connection capacity is expected to have been taken by offshore wind projects, leaving only the more costly connection points.

Balance of Plant - £240 per kW (or 6% of total Capex)

Balance of plant (BoP) items account mainly for the cost of project management, the cost of control and monitoring systems and other costs that can not easily be defined into the other categories.

It is expected that there will be significant savings in the costs of project development up to 2020 as lenders become more comfortable with the project risks following the first few installations. By 2020 it has been assumed that the 10% premium that was added to the capital cost of project development can be removed. Further streamlining of project development post-2020 is expected to bring further savings in the order of 5%.

3.7.2.4 Conclusions on floating wave

Although this estimate is highly speculative and based upon the support being available for projects to develop to such a stage that capital costs of £4000/kW are achievable by 2015 then floating wave devices show significant potential for cost saving. We anticipate modest savings by 2020 (some 12%) and more marked reductions by 2040, when capital costs are projected to be 73% of "current" levels, with most of reduction coming from cost savings in the prime mover, the wave power device itself – see Table 3.26.

Table 3.26: Projected capital costs of a floating wave device in £/kW installed

	2011	2020	2040	Costs in 2020 as % of 2011 costs	Costs in 2040 as % of 2011 costs
Site preparation & licensing[28]	440	422	401	96%	91%
Prime mover	2000	1694	1286	85%	64%
Foundations and moorings	700	617	527	88%	75%
Electrical works	660	608	530	92%	80%
Balance of plant	240	228	212	95%	88%

[27] From DECC report '*Cost of and financial support for offshore wind'* report number URN 09D/534 published April 2009

[28] This is effectively the same as development and planning, in other cost breakdowns.

	2011	2020	2040	Costs in 2020 as % of 2011 costs	Costs in 2040 as % of 2011 costs
Total	4040	3569	2956	88%	73%

Source: Mott MacDonald estimates

3.7.3 Shoreline Wave

A brief description is given of what shoreline wave energy is and how it would be harnessed in the UK. Key features of a generic fixed wave device that would be suitable for the UK are defined and these form the basis of our ‘representative case’, which is used to build up the capital cost model. The key assumptions used for the cost model are then described.

Key sources of information have included public domain web-based sources including reports by the Carbon trust, Renewables UK and DECC that present an appraisal of the capital cost of marine renewables.

It should be noted as a disclaimer that although there are a lot of aspirations for marine renewable generation to contribute to the UK’s energy mix, the industry is still very much in its infancy and is not currently at a state of commercial availability[29]. As the industry is at such an early stage of development there are a number of technology concepts developing side by side. It is hoped that in time the marine energy industry will consolidate and development efforts will become focussed only on those most promising options and thus accelerate the rate of learning. Estimates for future capital costs are highly speculative as not only are they dependant upon the specific requirements of wave device design (which is highly variable between concepts) but also on the learning curve of the industry overall, which will be reliant on demonstration projects being implemented. Demonstration plants will only go ahead if the various enabling mechanisms allow.

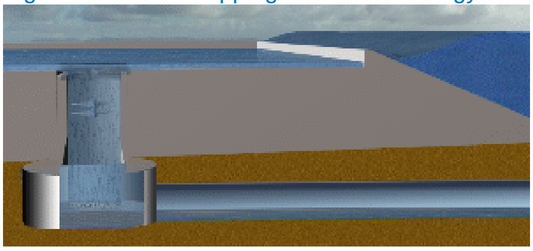
3.7.3.1 Technology description

A shoreline energy devices are mounted on the shoreline rather than out at sea and generate electricity from the interaction of the moving waves with a fixed structure. Two of the concepts that have reached the furthest stages of development are the Oscillating water column and the overtopping devices as illustrated in Figure 3-19 and Figure 3-20 respectively; the companies developing these technologies include Wave Dragon and Wavegen respectively. A detailed description of how shoreline wave technologies function is available on the European Marine Energy Council’s website http://www.bwea.com/marine/devices.html.

Figure 3-19: Oscillating water column fixed wave device

Source: EMEC

Figure 3-20: Overtopping fixed wave energy device



Source: EMEC

[29] Marine Renewable Energy: State of the industry report. Produced by Renewable UK in association with Entec. March 2010

The technology is essentially shore-based and does not require significant off-shore works or long electrical connections to shore, leading to large savings in the capital cost. The cost savings are likely to be offset by the large amount of additional civil and structural engineering necessary to build the fixed structure that channels / captures the waves.

3.7.3.2 Defining a representative plant for Capex estimate

There is little data available for the capital cost of an installed commercially viable fixed wave device because the technology has not yet developed to that stage although the Wavegen Limpit deployed on the island of Islay, Scotland claims to be the world's first grid-connected commercial scale wave energy plant and has been generating electricity since November 2000. It is necessary to define a hypothetical cost for a device that is capable of wider commercial application assuming that all of the enabling actions are been put in place.

A 50 MW array of fixed wave devices has been chosen as a representative scale of installation and it is assumed that generation will occur on the shoreline at a distance of several hundred metres from a grid connection point. A 50 MW installation is justified as a representative plant because it is typical of the scale of developments planned for the Pentland Firth under Round 1 of the Crown Estate's tidal and wave energy leases[30]. The Pentland Firth wave and tidal development is the world's first leasing round for commercial wave and tidal generation, which covers 600 MW of wave generation. The agreed developments and their respective capacities are listed as follows, which justifies the choice of 50 MW as a representative case.

- SSE Renewables Developments Ltd, 200 MW for Costa Head site
- Aquamarine Power Ltd & SSE Renewables Developments Ltd, 200 MW for Brough Head site
- Scottish Power Renewables UK Ltd, 50 MW for Marwick Head site
- E.ON, 50 MW for West Orkney South site
- E.ON, 50 MW for West Orkney Middle South site
- Pelamis Wave Power Ltd, 50 MW for Armadale site.

The Pentland Firth projects are not scheduled until 2020 so it must be stressed again at this point that the 50MW plant is a hypothetical case provided that wave energy R&D continues to develop at the necessary rate. A capital cost estimate of £ 3,270 / MW is highly speculative and reliant upon all enabling measures to be put in place to allow the industry to develop to a commercial state by 2020.

3.7.3.3 Explanation of Capex model inputs

The estimated breakdown of capital cost for a 50 MW fixed wave power development is shown in Table 3.32.

Table 3.27: Breakdown of capital cost for a fixed wave energy device

Item	Estimated Cost per kW	Proportion of cost
Development and Planning	£440	13%
Prime mover	£850	26%
Civil structure	£1,700	52%
Electrical grid connection	£40	1%
BoP (including assessment and demonstration)	£240	7%

[30] Crown Estate Press Release. March 2010. http://www.thecrownestate.co.uk/newscontent/92-pentland-firth-developers.htm

Item	Estimated Cost per kW	Proportion of cost
Total	£3,270	99%

Source: Adapted from MEG supply chain results

The capital cost breakdown shown above has been based upon a Marine Energy Group report[31] in which a number of wave and tidal energy developers were approached for their estimated capital costs. Some of the cost items have been adjusted to reflect the different nature of shoreline-based wave energy devices to off-shore floating wave devices, in particular the costs associated with civils and structural works is much higher for a shoreline device. In addition, the complicated mechanical power conversion devices associated with floating devices can be substituted for a comparatively straight forward turbine when generation is shore-based, which makes the cost of the prime mover significantly cheaper. A more detailed explanation of the assumptions behind the cost model for fixed wave devices is given in the following paragraphs.

Development and Planning - £ 440 per kW (or 13% of total Capex)

The figure of £400/kW for development and planning was quoted by DECC in its 2009 report[32] on the cost of offshore wind energy. Although no explanation of what exactly was included, the figure is consistent with Mott MacDonald's experience of the likely cost for securing project finance, which includes all the development necessary before a project can begin construction including environmental impact assessments, yield estimates, design, tendering and contract negotiation. It has been recognised that the costs associated with achieving project finance are likely to be more onerous for an unproven technology such as floating wave energy than for offshore wind so an additional 10% has been added to bring the total estimate to £ 440/kW.

It is expected that post-2020, the cost of project development is likely to fall as lenders become more comfortable with the commercial risks and project finance becomes less onerous. In addition, the reliability of energy yields is likely to increase as experience is built up of wave power generation and the cost of yield forecasting is expected to reduce. Thus the 10% premium is removed after 2020.

Post 2020, there is likely to be a reduction in the availability of good sites as there will be a large number of offshore wind farms by that time. A modest 5% increase in the cost of project development has been assumed.

Prime Mover – £850 per kW (or 26% of total Capex)

Prime mover cost includes the same cost of the mechanical plant and electrical generation plant that was included in the cost estimate for floating wave energy. The additional cost of structure is now assumed to be unnecessary and the equivalent cost has been ascribed to building the concrete and steel structure for channelling waves and creating the over-topping or oscillating column effect.

Installation of a shoreline device will not require the same vessel and port charges that a floating wave device would entail and 90% savings on vessel charges have been assumed over a floating wave-farm case.

[31] Marine Energy Roadmap, August 2009.

[32] From DECC report '*Cost of and financial support for offshore wind'* report number URN 09D/534 published April 2009

There is not expected to be any change in the cost of the prime mover between now and 2020 as it is only by 2020 that this technology is expected to be available on a commercial scale. Post-2020 there are likely to be few competitors in an emerging market and competitive pressures will not be present to drive down the cost of generators significantly. Production is unlikely to be on such a scale as to offer mass production and supply chain savings.

It has been assumed that the technological maturity is currently 70% by 2020 and may improve to 90% by 2040. The large expected improvement in technological maturity reflects the state of an emerging market.

Current material intensity is estimated at 5% and it is not assumed that there will be any reduction in the material intensity post-2020 because the technology is comparatively simple and well understood.

Cost savings of 10% have been assumed post 2020 as a result of new market entrants and a more established supply chain giving increased competition and driving down production costs.

Civil structure - £1,700 per kW (or 52% of total Capex)

A shoreline wave device requires a significant amount of structural steel and concrete to build the structure for channelling / capturing waves. The cost of civil works, estimated at £1,700, has been built up by adding the costs of the structure and the foundation for a floating device. The cost of civil works also includes transportation and installation costs plus a share of the support vessels.

Foundation cost includes manufacturing the structure (including large quantities of steel and concrete) thus a high material intensity of 20% has been assumed for the capital model, which is consistent with the material intensity estimates for foundations for offshore devices.

It has been assumed that post 2020, the material intensity can be reduced by 5% as designs become more developed and benefits are felt from learning from previous projects or modelling. Material costs themselves have been assumed to increase 10% in the base case model as the carbon intensive production of steel and concrete is likely to incur greater costs as it comes under increasing pressure to reduce emissions.

The heavy civil work necessary for shore-line wave energy will put the technology in direct competition with other large infrastructure projects for resources. It is difficult to predict whether there are likely to be costs savings from new market entrants but because the scale of the industry is likely to be limited by the number of suitable sites it has been assumed that no savings will arise as a result of increased market competition.

Electrical grid connection - £40 per kW (or 1% of total Capex)

The cost of electrical infrastructure is more inline with onshore generation than off-shore so the cost of connecting an equivalent capacity 50 MW onshore wind farm has been used as the basis of a price estimate. Onshore wind farms will be a good guide because they are also often in remote locations and at the end of the distribution network. MML's database of recent connection costs for on-shore wind gives us a guide capital cost of £2 million for connecting a 50 MW fixed wave facility, which equates to £40 / kW (less than a tenth of the cost of offshore connection).

Smaller material volumes are used in the connection of a shore based technology than for an off-shore technology and from the MML internal database of connection agreements it is estimated that 10% of the connection cost relates to the cost of materials.

Post 2020, it has been assumed that there will be no change to the cost of connection.

Balance of Plant - £240 per kW (or 7% of total Capex)

BoP accounts mainly for the cost of project management, the cost of control and monitoring systems and other costs that can not easily defined into the other categories.

It is expected that there will be significant savings in the costs of project development up to 2020 as lenders begin to get comfortable with the project risks following the first few installations. By 2020 it has been assumed that the 10% premium that was added to the capital cost of project development can be removed. Further streamlining of project development post-2020 is expected to bring further savings in the order of 5%.

3.7.3.4 Conclusions on capex for shoreline wave

Although this estimate is highly speculative and based upon the support being available for projects to develop to such a stage that capital costs of £3,270/kW could be achievable by 2015 then shoreline wave devices show significant potential for cost saving. We project that by 2020 capital costs could fall by over one fifth and two fifths compared with current levels by 2020 and 2040, respectively. The main cost reductions are expected to occur in the major civil works/moorings and the prime mover – see Table 3.28.

Table 3.28: Projected capital costs for fixed wave device in £/kW installed

	2011	2020	2040	Costs in 2020 as % of costs in 2011	Costs in 2040 as % of costs in 2011
Site preparation & licensing	440	396	356	90%	81%
Prime mover	850	632	422	74%	50%
Foundations and moorings	1700	1281	915	75%	54%
Electrical works	40	34	27	85%	67%
Balance of plant	240	205	175	85%	73%
Total	3270	2548	1896	78%	58%

Source: Mott MacDonald estimates

3.7.4 Tidal Stream (hypothetical)

A brief description is given of what tidal stream energy is and how it would be harnessed in the UK. Key features of a generic tidal stream device that would be suitable for the UK are defined and these form the basis of our ‘representative case’, which is used to build up the capital cost model. The key assumptions used for the cost model are then described.

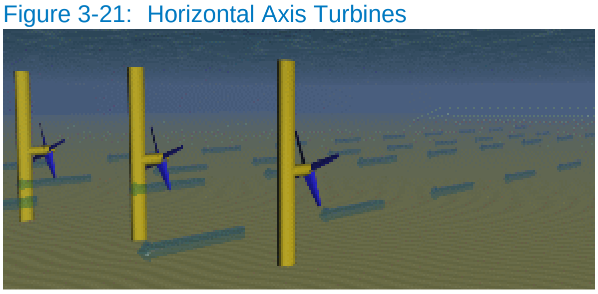
Key sources of information have included public domain web-based sources including reports by the Carbon trust, Renewables UK and DECC that present an appraisal of the capital cost of marine renewables.

It should be noted as a disclaimer that although there are a lot of aspirations for marine renewable generation to contribute to the UK’s energy mix, the industry is still very much in its infancy and is not currently at a state of commercial availability[33]. As the industry is at such an early stage of development there are a number of technology concepts developing side by side. It is hoped that in time the marine energy industry will consolidate and development efforts will become focussed only on those most promising options and thus accelerate the rate of learning. Estimates for future capital costs are highly speculative as not only are they dependant upon the specific requirements of tidal stream or wave device design (which is highly variable between concepts) but also on the learning curve of the industry overall, which will be reliant on demonstration projects being implemented. Demonstration plants will only go ahead if the various enabling mechanisms allow.

3.7.4.1 Technology description

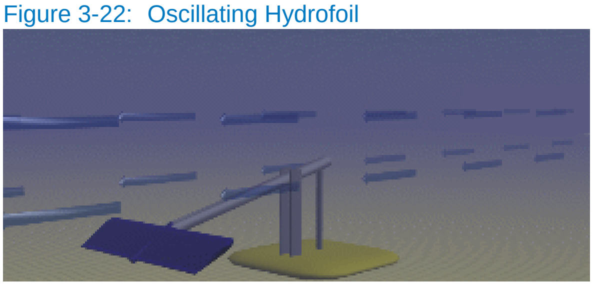
A tidal stream device is the term used to describe devices that are placed offshore and generate electricity from mechanical motion caused by tidal currents. There are several concepts that fit the description of 'tidal stream devices' and two examples are the Horizontal axis turbine and the oscillating hydrofoil as illustrated in Figure 3-21 and Figure 3-22. A detailed description of how these technologies function is available on the European Marine Energy Council's website http://www.bwea.com/marine/devices.html.

Figure 3-21: Horizontal Axis Turbines



Source: EMEC

Figure 3-22: Oscillating Hydrofoil



Source: EMEC

Floating wave devices are typically located several miles offshore and are anchored to the sea-bed via moorings or foundations depending upon the concept design.

3.7.4.2 Defining a representative plant for Capex estimate

There is no available data for the capital cost of installed commercially viable tidal stream devices because the technology has not yet developed to that stage and only a limited number of demonstration projects have been built. It would not be sensible to use the cost data from existing prototype and pilot projects upon which to base learning curve projections as it is understood that these current projects would be disproportionately expensive (currently estimated at £10,000/ kW[34]). Mott MacDonald is unable to verify this estimate but it appears to be at the high end of our expectations, which is consistent with a document that was written to encourage government investment in the industry. Press reports for the demonstration device at Strangford Lough in N.Ireland put the price at £8.5 million for the 1.2MW Seagen device, which is more in line with our expectations, equating to £7,083/ kW.

The 1.2MW Seagen horizontal axis turbine at Strangford Lough has been chosen as a representative scale of installation and it is assumed that the device is operating within 500m of shore where the depth is 10-

[33] Marine Renewable Energy: State of the industry report. Produced by Renewable UK in association with Entec. March 2010

[34] "The Next Steps for Marine Energy – Action Plan" published by Renewables UK (March 2010)

15m. The device is assumed to be anchored to the seabed via pile foundations. In order to keep the results generic, it has been assumed that the cost of foundations will be similar to that for an offshore wind farm on a £/MW basis and it is fair to assume this because even though the foundations for floating devices would not need to be as strong as for offshore wind turbines, the capacity of each device is likely to be lower than the 3-5 MW offshore wind turbines and so the cost per MW is likely to be in the same range. It is worth noting that the jack-up barge used to install the Seagen device is the same vessel that has been used to install several offshore wind farms, A2Sea's 'Jumping Jack'.

The capital cost of a tidal stream installation is estimated at £3,200 – 4,000 / kW which is an estimate based upon the results of a survey performed in a study for the Marine Energy Group (the August 2009 RoadMap report) for a project that would be commercially available in 2014. The capital cost estimate is supported by the cost of Strangford Lough, which is estimated at £7,000/kW, which, as a demonstration project, would be expected to see capital costs significantly higher than a commercial plant. The £ 3,200 – 4,000 / kW estimate assumes that all enabling measures have been put in place to allow the industry to develop to a commercial state by 2014. We have taken the mid point of these figures for the purposes of our analysis.

3.7.4.3 Explanation of Capex model inputs

The estimated breakdown of capital cost for tidal stream device is shown in Table 3.29.

Table 3.29: Breakdown of capital cost for a floating wave energy device

Item	Estimated Cost per kW	Proportion of cost
Development and Planning	£440	12%
Prime mover	£1,500	41%
Foundations / moorings	£800	22%
Electrical grid connection	£660	18%
BoP (including assessment and demonstration)	£240	7%
Total	£3,640	100%

Source: Adapted from MEG supply chain results table (reference)

For want of more detailed publicly available information, and recognising that there are still several concepts for tidal stream generation and that a proven technology has yet to clearly emerge, the capital cost estimates are thought to be a little less than floating wave devices.

3.7.4.4 Conclusions on tidal stream capex

Although this estimate is highly speculative and based upon the support being available for projects to develop to such a stage that capital costs of £3,200 – 4,000/kW are achievable by 2015 then tidal stream devices show significant potential for cost savings by 2040. In the near to medium term we expect to see only moderate reductions in Capex as there will still be few market entrants and the technology will have to gain some operational experience before technology developers and financiers invest in larger production facilities that will lead to savings in the supply chain. As things stand, there is no clear preferred technology and until a concept emerges as operationally proven it is hard to be anything but generic about capital cost estimates. Even so by 2020, given a strong push we could see reductions of around a fifth on current, with further reductions to 73% of current levels after this.

Table 3.30: Projected capital costs for tidal stream devices in £/kW installed

	2011	2020	2040	Costs in 2020 as % of costs in 2011	Costs in 2040 as % of costs in 2011
Site preparation & licensing	440	418	397	95%	90%
Prime mover	1300	780	557	60%	43%
Foundations and moorings	1000	741	571	74%	57%
Electrical works	660	506	446	77%	68%
Balance of plant	240	195	176	81%	73%
Total	3640	2640	2147	73%	59%

Source: Mott MacDonald estimates

3.7.4.5 Outlook for levelised costs of electricity from marine technologies

The projected reductions in capex for the three generic marine technologies mentioned above indicate a significant improvement in levelised costs. This is compounded by a projected decline in the risk premiums for these technologies which sees the discount rates falling several percentage points. On the basis of the significantly higher ACF projected for tidal stream versus wave (and the comparable capex and opex) we are projecting that tidal stream will have the lowest levelised cost of electricity (LCOE) of the devices, falling from a hypothetical current cost of £293/MWh to £180/MWh and £120/MWh in 2020 and 2040 respectively, using our central case discount rates. The comparable LCOE for floating wave devices in 2020 and 2040 is £300/MWh and £200/MWh, respectively. Shoreline wave devices are projected to have a LCOE that falls between tidal stream and floating devices, largely reflecting its capex advantage versus floating devices. These projections and the relative positions of the technologies remain highly uncertain, as we lack practical evidence of out-turn production and installation costs, device reliability and availabilities.

3.8 Geothermal

A brief description is given of what geothermal energy is and how it would be harnessed in the UK. Key features of a generic geothermal plant that would be suitable for the UK are defined and these form the basis of our ‘representative case’, which is used to build up the capital cost model. The key assumptions used for the cost model are then described.

Key sources of information have included public domain web-based sources such as EGS Energy, academic papers and interviews with Mr R.Law (Chairman of the UK Deep Geothermal Group), and M.Feliks, (Geothermal representative for DECC).

3.8.1 Technology description

An engineered geothermal system (EGS) harnesses the energy in the earth to produce commercial quantities of electricity. The basic principle of an EGS is to access the high temperature available at depth and manipulate the underground rock mass to enhance permeability so that cooled water can be injected from one well and steam or hot water is returned from other wells, at an acceptable cost.

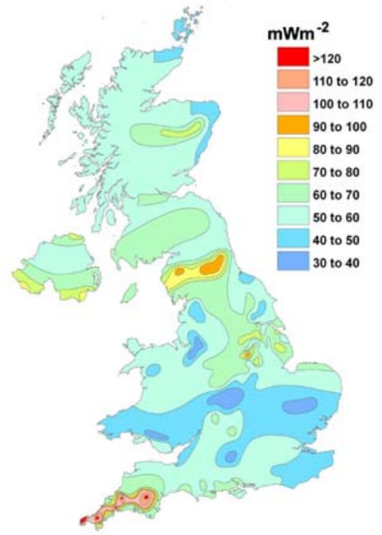
Hot igneous rocks can be at considerable depths in the earth’s crust, as in the UK, and so reaching them with conventional drilling equipment is costly and difficult. First, there needs to be exploration to locate high-temperature rocks within achievable drilling distance. Second, the rocks need to be sufficiently fractured or demonstrate potential for artificial fracturing to allow hot water to be circulated and produced at sufficiently high rates.

The hot water (150+°C) once brought to the surface is then used to drive a conventional turbine, with each two well module generating between 3-6MW. A three well system might produce 10-15MW gross.

3.8.2 Defining a representative plant for Capex estimate

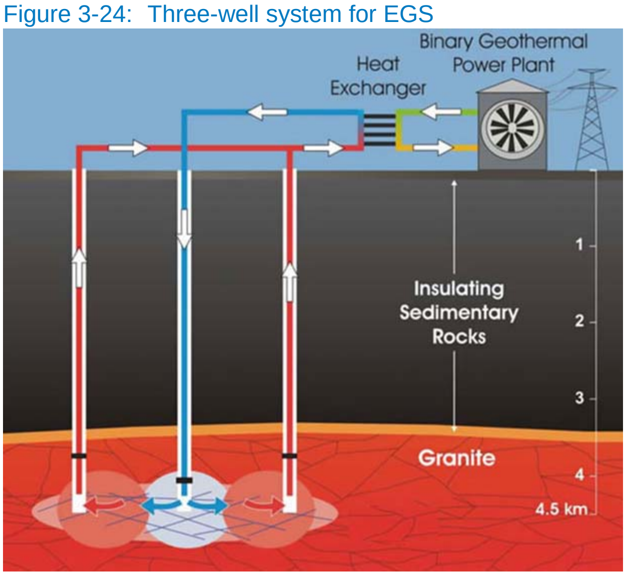
Because they have the highest heat conductivity and are considered the easiest win, granite outcrops are preferred for EGS. The location of the granite outcrops corresponds with the darker coloured areas on the heat flow map of Britain (Figure 3-23). In the granite areas, temperatures of around 180^{o}C are to be expected at this depth. We have assumed a three-well configuration as shown in Figure 3-24, which means that there are two outer wells for extracting hot water and one central return well (which returns the 'cooled' water back to the ground in a closed loop).

Figure 3-23: Heat flow map of the UK



Source: British Geological Survey website. www.bgs.ac.uk/research/energy/energy_geothermal.html

Figure 3-24: Three-well system for EGS



Source: Katusa, M. *A hot future for geothermal* energy" http://www.marketoracle.co.uk/Article15742.html

The target capacity of 10 MWe (gross) is achievable for an EGS in the UK and there is additional opportunity to extract 10-50 MW_{th} of thermal energy but that will depend upon the local demand for low grade heat and what cascading is used. It should be noted that the parasitic load on EGS is high due to the large pumping and cooling requirement. A 10MWe (gross) facility is likely to export in the region of 7 MWe.

The key features of a representative UK enhanced geothermal system are given in Table 3.31, which form the basis of the capital cost estimate. It should be noted that although a 10 MWe geothermal plant would be capable of providing up to 50 MWth of additional heat energy, the equipment required to harness the thermal energy has not been included in the capital estimate. Low-grade heat (typically <90^{o}C) is useful for heating or potentially thermal chilling. The focus of this capital cost exercise has been in terms of electrical generation so the additional thermal energy should be considered as a side benefit that would require additional investment for heat exchangers, heat grids and metering before it could be used.

Table 3.31: Key features of a representative plant for the UK

Feature	Description
Size and configuration	10 MWe (gross) binary plant
Drilling depth	5,000m
Number of wells	Three (two production and one return)
Temperature	180°C
Current Capital cost of geothermal	£4,600/kWe

Source: MML Assumptions

3.8.3 Explanation of Capex model inputs

Capital costs for geothermal energy have been broken down into the following five, high cost items as presented in Table 3.32 below:

Table 3.32: Geothermal Capex Estimates

Cost Item	Current estimated cost for 10 MWe facility £/kW	Proportion of total Capex (%)
Drilling and Casing	2400	52
Binary Process Plant (Fully wrapped EPC)	1500	32
Project set-up development (resource assessment, planning & consenting)	300	6
Geophysical tests during drilling	200	5
BoP and Electrical Connection	200	5
Total	4600	100

Source: MML Estimates 2010

Each cost item is discussed separately below and an explanation is given as the assumptions regarding the current cost and the forecasted adjustment to costs.

Drilling and Casing – The drilling work, currently estimated at £24 million, includes installation of steel tubular casing and is heavily dependant upon the availability of drilling rigs, developments in drilling technology and the cost of steel for the casing.

We are aware that Germany has begun to build bespoke drilling rigs for geothermal wells and when there are a number of drilling rigs then the increased competition is expected to bring down the cost of drilling before 2020.

It has also been suggested that there may be a step change in drilling technology, post-2020, that would lead to large reductions in cost (in the order of 20%) by 2040. It has been assumed that the technology is perhaps 70% developed at present and is expected to be 75% developed by 2020 and possibly 95% developed by 2040. Although such predictions are largely subjective, it is thought that as companies gain experience in drilling geothermal wells and as expertise are transferred and adapted from the oil industry that such savings are achievable.

The overall cost of drilling and casing has been estimated to be 10% reliant on material costs due to the steel involved in the well casing. Steel is a carbon intensive industry and is likely to be affected by international carbon prices so the projections for materials pricing have been considered for the future cost projections.

Binary Process Plant – The cost of and EPC contract for a Binary process plant has been estimated at £15 million based upon experience from the United Downs geothermal power station in Cornwall[35] and other published data. The Capex estimate of £15 million (or 32% of the total Capex) is consistent with an estimate described by Thorsteinsson, et al. (2008)[36], which gives the following equation for estimating binary plant cost where 'C' is the cost in USD/kWe and 'T' is the temperature in ^{0}C.

$$C = 2,642 - 3.5T$$

For a design temperature of 180^{o}C, the cost would be $2,012 per kW which equates to roughly £13 million pounds for a 10 MWe project.

It has been noted that there are a growing number of binary plant companies in the market and that process plant costs are expected to fall perhaps 5% by 2020. The plant has been considered to be near to technical maturity with technology improvement limited to around 5% by 2040. Furthermore, binary plant has been assumed to have a materials intensity of 10% and will likely be affected by world prices for steel and other materials.

Project set-up and development. – Project set-up cost has been estimated at £4 million and includes the cost of developing a project, performing the resource assessment and finally achieving the necessary planning and consent.

Ryan Law, who is the chairman of the UK deep geothermal group, has suggested that the costs of exploration are likely to decrease linearly to 2050 by which time they will have fallen 90% as a result of more geophysical information being available from existing projects.

Planning and consent costs are forecast to rise beyond 2020 once the concept has been proven by the few pilot scale examples and a larger volume of developers look to build their own projects. As the project development costs rise, it may be expected to outweigh the savings from resource estimation.

Geophysical tests during drilling – A number of tests are performed during the drilling activities to measure such variables as rock type, permeability and stresses. These tests are important to the drillers and operators of geothermal wells as they influence both how the well is drilled and how it is subsequently operated. The importance of the geophysics tests are such that no cost reductions are expected.

BoP and electrical connection - It is difficult to estimate the cost of electrical connection as equipment needs and line lengths is very location specific. However, the current cost has been estimated at £200/kW for a 10MWe facility, which also accounts for BoP activities such as remedial environment work, compound security and other costs not covered by the EPC contract.

[35] UK project that has received DECC grant funding and is expected to begin drilling in 2011. http://www.geothermalengineering.co.uk/

[36] Thorsteinsson, H et al. (2008). *The impacts of drilling and reservoir technology advances on EGS exploitation*. Proceedings from 33rd workshop on geothermal reservoir engineering January 28-30, 2008, Stanford university.

It has been estimated from the MML internal database of electrical connection costs in the UK that the proportion of the connection price associated with materials intensity is approximately 10%. The cost of materials themselves have been assumed to rise by around 10% by 2020 and a further 10% by 2040 (increased this to 15% per period for the high case and reduced it to 5% for the lower case). The reason for assuming an increase in material price is that concrete, steel and copper production are carbon intensive industries that are likely to face increasingly costs as the price of carbon becomes factored into production.

3.8.4 Conclusion on geothermal costs

- The key cost items are the drilling, casing and binary plant, which together constitute approximately 83% of the total Capex costs for developing a geothermal engineering project.
- Large savings (in the order of 20%) are expected in the cost of drilling in the period 2020-2040
- Increase in material costs are expected over the same period
- Overall Capex reduction in geothermal energy of around 5% by 2020 and 14% by 2040.

Operating costs for geothermal plant are comparatively low, assuming that the geothermal resource does not require new make up wells or significant additional drilling. While output may fall over time, average annual capacity factors for good sites should be near baseload on 20-25 year life. All this suggests that while the specific capital cost is comparatively at £4,600/kW, the LCOE could be comparable with offshore wind today. Using Oxera's central case discount rates we get a levelised cost of £115/MWh and £80/MWh in 2020 and 2040, respectively.

3.9 Nuclear

3.9.1 Current costs and drivers

The nuclear technologies under current review in the UK include two advanced (3rd generation+) pressurised water reactors (PWR). It is expected that by 2020, other PWR models as well as boiling water reactors (BWR) will be certified under the UK's generic design assessment (GDA) process. Beyond 2020 there are many other possible reactor designs, most notably small modular reactors, high temperature (gas cooled) reactors (HTR) and fast neutron reactors (FNR). In this report we focus on the PWR and BWR options, at least in terms of the detailed cost assessments, however we comment on potential costs of the other options.

There is considerable uncertainty about the current costs of newbuild nuclear in the UK, largely because there is no recent track record of projects and only limited indications of the current preliminary tender prices or developers' budgets.

The headline figure often talked about by the leading UK developers (EdF and Horizon) and the UK government is £10bn for a twin or triple unit plant with a capacity of about 3GW net. This is equivalent to about £3300/kW. This figure is comparable to the revised estimates for the two EPRs under construction in Finland and France (Olkiluoto 3 [OL3] and Flamanville 3). This price is about double our estimate for a new super critical coal plant (excluding CCS). It is also about 50% more than the reported price for UAE's price for Kepco's APR concluded in late 2009 (about £2400). This Korean price has been broadly matched by BWR quotes into the USA, although this excludes any contingencies that might be applied by the contractors and developers. We have rounded the figure up to £3500 to allow for suppliers and contractors contingencies.

It remains to be seen whether the outturn prices for the UK will be so far above the Korean benchmark, as there is a possibility that the two vendors may aggressively compete for orders, especially if either of them considered there was a real risk that other developers' interests could wane. That said, most observers consider that the UK price will be done at considerable premium to the Korean price.

This premium reflects the high costs of the "untried" reactor models, the more demanding regulatory scrutiny and higher labour costs (and lower productivity) in the UK. Some would also argue that a contest between just two vendors for two clients is unlikely to lead to the most aggressive pricing.

There is little evidence that nuclear prices have softened since mid 2010, as big coal plant appears to have done. IHS-CERA's PCCI index has shown for the US at least, that nuclear costs continued on an upward trend through 2010.

From an engineering point of view nuclear should not be that much more difficult than a coal station. There is a different "black box" in the system, however the equipment costs for this are typically a small share of the total capex – as low as 10% in some cases. However, the primary difference between coal and nuclear is the level of certification required across almost all stages of assembly and construction. Coupled with this is the much lower tolerances accepted by certification authorities compared with conventional power plant. This in turn means there is a special requirement for skilled workers and certainly having a workforce that is conscious of need for compliance. This is one of the reasons for the extremely high share of on-site labour and supervision in nuclear plants – accounting for over 55% in one project currently moving towards financial close. In contrast, the reactor and materials account for just 25%, of which just over one third is for the reactor (though this excludes fabrication and of course its civil structure).

Table 3.33 shows MML's assessment of current capital cost build up for a PWR in the UK, with costs expressed in £/kW installed on the basis of a 2-3 units with a net capacity of about 3GW. There is considerable uncertainty about the levels and the breakdown however we are confident of the general relativities. Civil works (which comprise foundations and buildings and other containment structures) comprise the largest item at 40%, while the reactor island is the second major item at almost 30%. Most of the other items are relatively small, although site preparation and licensing can be substantial at approaching 10%. The fuel pathway, which comprises the fuel transport, handling and storage is comparable to the costs for a coal or woody biomass fired plant. Other items such as electrical works, turbine island and balance of plant equipment are similar to that on a big coal fired plant.

It should be noted that the estimate in Table 3.33 includes the uplift from the current congested EPC market. MML's view is that this is around 20%, similar (if not higher) than that for large supercritical coal plants. This congestion premium is thought to be most marked for the nuclear components, the civil works and turbine-island and mainly reflects supply chain constraints.

Table 3.33: Indicative capital cost breakdown for a PWR ordered in the UK in 2011

Cost component	£/kW installed	% share of total costs
Site preparation and licensing	325	9%
Reactor island (including steam generator and primary cooling)	1000	29%
Turbine island	225	6%
Fuel pathway	250	7%
Civil works	1400	40%
Electrical works	125	4%

Cost component	£/kW installed	% share of total costs
Balance of plant	175	5%
Total	3500	100%
Note: Figures include a market congestion premium of about £700/Kw		

Source: Mott MacDonald estimates

The critical driver for nuclear capex is how it is built. This is as much about the way it is built as the experience of the supply chain. Some vendors (such as GE-Westinghouse) argue that significant cost reductions will only come through increasing the level of modularisation and off-site fabrication. There are reports from China of dramatic improvements in the build time and quality control of various sub-modules for AP1000, arising from third and fourth plants. Other vendors argue that it does not matter where the unit is made, it is rather a matter of applying the appropriate check and controls and using experienced and committed contractors.

While there is no current BWR option for the UK, we have for the purposes of completeness provided an estimate on the basis as a comparator. There is a general view that BWR should have a modest cost advantages versus PWR, since they operate at lower pressure and have a simpler cooling arrangements. However as mentioned above, the reactor equipment accounts for such a small part of the costs that this unlikely to be a key driver. The primary driver will be how well the plant is designed and how familiar the supply chain is with putting it together.

The capital costs mentioned above exclude any allowance for decommissioning. As in the previous DECC analysis, plant decommissioning costs along with waste management costs are factored in as charge on generation – assumed to be £2.5/MWh in the central case. This cumulates to £1,200/kW over 60 years of base-load operation, assuming no interest. DECC's analysis (of 2007) argued that there would be some fund growth above this as it is assumed that the fund could achieve a real rates of growth of around 2% pa during the operating life. Whether this is still the current view given the current financial situation is unclear. However, even on a non interest basis this represents almost 40% of the initial plant capex.

The nuclear OEMs have put increasing emphasis in recent years on designing and building plant to ensure very long lives, and 60 years is now the design life for many PWR and BWRs. They have also sought to increase plant availabilities by reducing downtime for refuelling. Together, these factors imply that a newbuild PWR or BWR can be expected to yield more MWh per MW over its lifetime than probably any other power plant technology.

3.9.2 Outlook for costs

Many of the issues that were discussed above in influencing the current outturn capex price apply to the forward assessment. Should the UK progress to implement its currently planned four multi-unit stations then there should be scope for capturing the benefits from learning and upgrading the supply chain. This is the bullish scenario.

Under a more cautious scenario with a more tentative programme, the UK (and probably also Western Europe) is likely to be relative backwaters when it comes to learning by doing in the nuclear arena, compared with the likes of China, Korea, Russia, Japan and India. This reflects the expectation of limited newbuild activity in EU and US, largely as a result of low cost gas, greater market risk and the shorter payback requirements and reluctance to take on debt of EU/US investors. Taking this world view, the greatest scope for nuclear cost reductions will probably derive from learning from the application of new reactor models and new production techniques in non-EU jurisdictions.

On the basis of the learning rates observed in the literature and a modest rate of projected doublings in deployed capacity (based on a aggregate category of nuclear) the outlook for cost reductions is projected to be modest. However, this picture embodies the assumption that the nuclear industry will continue to be dogged by a regulatory process is subject to change during the construction process, requires design modifications and has limited continuity in contractors and OEMs.

Our view is that this is overly pessimistic. The central case for the engineering based assessment builds in considerable cost reductions even by 2020. The UK's GDA (Generic Design Assessment) process has narrowed the field of competitors, but it does promise the potential of reducing the need for on-going changes through the construction process. Post 2020, the scope for cost reductions increases as the UK should have access to more reactor models and vendors.

It is unclear whether the UK would eventually be able to access the low costs that Korean and other suppliers are offering. This will depend on the extent to which the UK's compliance requirements preclude some of the lower cost models. It will also depend on the extent to which the major Western OEMs' GDA compliant plant will use low cost "outsourced" components, but "badged" as a Western offering.

Our central view is that capital costs for PWR and BWR (we see little difference between them) will fall from £3500/kW today to £2000-2500/kW in 2020 and £1600-2450/kW in 2040. This assumes that the whole of the current market mark-up, which is worth over £700/kW is eliminated by 2020. It will also require that the construction process in future moves away from the current substantial requirement for onsite labour, through better logistics control and/or increased reliance on offsite modular assembly. Table 3.34 shows the projected cost projections under MML's central case for 2020 and 2040. This shows the biggest savings in civil works, reactor island and fuel pathway, which reflects a combination of end of market congestion and application of learning and supply chain improvements.

Table 3.34: Projected capital costs for nuclear PWR ordered in 2020 and 2040 (central assumptions)

	Installed capital costs: £/kW				
	2011	2020*	2040*	% of 2011 costs in 2020	% of 2011 costs in 2040
Site preparation and licensing	325	278	264	86%	81%
Reactor island	1000	734	626	73%	63%
Turbine-island	225	180	167	80%	74%
Fuel pathway	250	178	154	71%	61%
Civil works	1400	987	815	71%	58%
Electrical works	125	106	99	85%	79%
Balance of plant	175	146	134	83%	77%
Total	3500	2608	2259	75%	65%

* Assumes congestion premium (~£700/kW) is included in 2011, but is excluded from 2020 and 2040 figures.

Source: Mott MacDonald estimates

Applying the historical learning rates the reduction would just match the higher end of our engineering assessment. Adding back the current congestion premium would give a cost only a little below the current starting estimate of £3500/kW for a plant ordered today. Some commentators, such as Professor Steve Thomas in University of Greenwich, argue that past experience suggests actual costs will rise in real terms. MML believes that this is entirely possible, however, a combination of the GDA process, greater focus on project logistics and increased international competition in nuclear equipment markets, points to a turnaround on past trends and significant real reductions over the next decades as being a more plausible outcome.

These projections are based on an evolution of the current technologies. There are however a number of potential new technologies which could be deployed within the back end of this time frame. These include a number of small and medium reactors, several of which commercial demonstration are under construction. The World Nuclear Association reviews of small and medium sized reactors lists at least 12 reactor designs of 10MW to 700MW where development is well advanced and several are moving ahead to the licensing stage. These are being developed by a disparate group of developers in over 12 countries, only a minority of whom are established OEMs in the nuclear sector. A significant group are based on scaling up reactors for submarines and icebreakers. Invariably, all are designed as modular systems which promise long intervals between fuelling. In principle, some of these could be deployed in the 2020s, however, it remains to be seen to what extent the IAEA will be comfortable with a widespread deployment of small devices. It is too early to say anything concrete about the costs, except that the suppliers of these small reactors will hope that the savings from modularisation and mass production should offset the diseconomies of scale.

Other technologies which are on the horizon are high temperature (gas cooled graphite moderated) reactors (HTR) and fast neutron reactors (FNR). China is reportedly already building a demonstration HTR and is planning to start a full scale one around 2020. Assuming that this is built and the technology works this could potentially be deployed commercially sometime after 2030. Fast neutron reactors (fast breeder reactors, etc) – have a long history in Europe and Japan, but now this area is being led by India and Russia - though MHI of Japan also sees this technology as appropriate for 2040-50. FNRs have the advantage of better fuel economy and also the ability to burn up plutonium.

In the end the new reactor models will need to have clear advantages in order to be deployed. This may be in terms of fuelling efficiency, ability to modulate output (likely to be required under some scenarios where nuclear plays the balancing role around renewables), longer refuelling cycles, safer fuels and lower cost fuels (some based on thorium blends) as well as prospects of potentially lower capital costs.

Outlook for levelised costs

The projection of reducing capital costs is the main driver for levelised costs over the next decades. Fixed operations and maintenance costs are expected to fall with capital costs, while fuel costs are comparatively small. With plant lives and availabilities unlikely to be significantly improved, there is little scope for further fixed cost dilution, so cost reduction rests on the capex cost improvements. Under our central case projection levelised costs fall from £89/MWh for a plant ordered today to £63/MWh and £50/MWh for plants ordered in 2020 and 2040, respectively, using the central discount rate projection[37] and removal of the congestion premium. Of course, these costs are extremely uncertain and there is a large band of uncertainty, which stretches from a level that matches the current cost to one below £40/MWh by 2040.

[37] For nuclear, this falls from 11% in 2011 to 9.5% in 2020 and 7.5% in 2040.

3.10 Carbon capture and storage on coal and gas fired plant

3.10.1 Introduction

Carbon capture and storage (CCS) on power plants is at an early pre-commercial stage in its development, however it is seen as major carbon abatement option, given in principle it should be a “simple” add-on to existing fossil fuel fired generation plant. In most cases the addition of carbon capture (CC) involves adding or integrating a complex chemical process plant to what has traditionally seen as an electrical and mechanical engineers domain of electric utility plant.

There are three main components to the costs of carbon capture and storage on power plants:

1. direct costs of the capture plant;
2. indirect costs of relating to impact on the base power plant – often called host plant compensation
3. direct costs of transporting and storing the CO_2 (or otherwise sequestering the carbon).

The analysis here is concerned with the costs of capture alone. Transport and storage costs are excluded as these are likely to vary considerably by location (access to transport networks and sinks), nature of sinks and scale of operations. Instead, these back end transport and storage costs are treated as a charge on the operating costs of the host plant, based on the tonnes of CO_2 captured.

We have considered CC on coal and gas fired CCGT plants. CC could also be applied to biomass combustion and gasification plant (in which case the plant would actually generate negative emissions), however this is not considered any further here.

Since there is no commercial scale application of CC on power generation plant anywhere estimates of costs, build time and plant performance are based on small pilot plants, engineering studies and experience from comparable technologies. This means that the reader should be aware of the considerable uncertainty regarding the estimates reported in the literature and indeed the figures estimated here. While there are several commercial demonstration projects under construction, it is unlikely that a CC vendor would offer a full utility scale plant without huge and onerous contingencies. We have therefore extrapolated a hypothetical current full scale project on the basis of industry insights from feasibility and feed studies on demonstration projects. These can be considered the costs that would be applicable in the near term (within the next 12-18 months) assuming an equivalent “war time effort”.

We now consider CC on coal and gas plants in turn.

3.10.2 Carbon capture on coal plant

For coal there are three capture options:

1. Post combustion capture (PCC) applied to conventional combustion plant and currently the leading option;
2. Oxy combustion capture (OCC), also applied to conventional combustion plant, but less advanced than PCC and;
3. Integrated gasification combined cycle (IGCC) with pre-combustion capture, which contrasts to the combustion based options, in that it requires the adoption of an alternative approach to coal generation, gasifying coal to make syngas which is used to drive a modified CCGT.

The IGCC+CC option represents easily the least cost add-on, versus the base power plant. However, the adoption of this option rests upon driving cost reductions and availability improvements in the base IGCC technology, which after 25 years of experience has yet to offer a bankable alternative to super critical steam turbine base plant.

For PCC, the direct costs are dominated by the absorber and stripper, which together account for 70% of the capex. Oxy combustion cost is even more dominated by one item, the air separation unit (ASU), which currently is an expensive cryogenic process plant. The direct costs for the IGCC option are much less, because the base plant itself involves gasification and gas treatment and the main incremental cost is separating out the CO_2 from the carbon monoxide (CO) using a water shift process and then compressing the CO_2 for export from the site.

Direct costs vary from £335/kW for IGCC-CC to about £900 for both the oxy-combustion and post combustion options.

The costs of compressing CO_2 in terms of the equipment cost (large compressors) and increased auxiliaries load are common element of all the technology costs, although clearly these are higher for coal plant given the higher carbon intensity of generation. Typically, the capital costs are £120-200/kW.

The indirect costs reflect the costs of compensating for the energy penalty (stolen MWs of electrical output) which arises because of the additional parasitic electricity load and the need for thermal energy in the processes (which itself means less thermal energy to be converted to power)[38]. This energy penalty can be expressed as a percentage point reduction in electrical conversion efficiency, over the base plant efficiency. For all three processes the penalty is around 10% (percentage points) over 42%, which is about 24% (10/42). This energy penalty can be expressed as the cost of scaling up the gross MW of the host plant, which will of course depend on the specific capex cost of the base power plant.

Here CC on coal plant fairs poorly versus CC on CCGT, given the much higher energy penalty and the high specific capex costs.

In the modelling approach adopted for this analysis, the auxiliary load is separated out, such that the only indirect penalty that needs to be added for the capital costs is the thermal one. The capital cost model develops a cost per gross kW, which is then converted to a levelised cost per net MWh through deducting the up-rated auxiliary load. This treatment of auxiliary load effectively factors in the host plant compensation relating to the electrical penalties.

In terms of incremental cost of CCS on the base power plant costs, IGCC is the clear winner. However, given the higher costs of an IGCC base power plant, its overall cost of generation is expected to be a little higher.

Table 3.35 shows our estimate of capital costs for a newbuild super-critical coal station fitted with post combustion capture, which is assumed to be ordered today. This cost build-up includes our estimate of the market congestion premium which we put at about 12%. This shows the total CC cost is a little over £1100/kW, which compares with a base plant cost of £1600/kW. The direct CC costs dominate, accounting for almost £900/kW. In comparison, indirect costs are about £260/kW, however this ignores the auxiliary load penalties, which are broadly similar in magnitude. The largest item (at £450/kW) in the CC direct

[38] Though not for oxy combustion as mentioned below.

costs is the exhaust section, which is dominated by the absorber (the massive vessel where the initial reaction between the flue gas and solvent take place). The next largest item is the compression stage at £180/kW, with the circulation/stripper stage accounting for £100/kW.

Table 3.35: Indicative current capital costs of post combustion capture on a super-critical coal plant

	£/kW installed	% share of total plant costs	% share of CC costs
- Site preparation and licensing	60	2%	5%
- Exhaust section	450	17%	40%
- Circulation/ Stripper	100	4%	9%
- Compression	180	7%	16%
- Balance of capture plant	75	3%	7%
Direct CC costs	865	32%	77%
Host plant compensation*	256	9%	23%
Total CC costs*	1121	41%	100%
Base power plant	1600	59%	-
Total	2721	100%	-

* includes only thermal penalty not extra aux. load

Costs include a market congestion premium of about 12%

Source: Mott MacDonald estimates

The cost structure for coal with oxy combustion capture has some similarities with that above. The base costs are the same. However, there are no indirect costs – host plant compensation – as we have defined it here (though auxiliary load is much higher). The direct costs are dominated by the ASU, which is estimated to costs around £600/kWh, while the compression stage is the same as in the PCC application.

IGCC with pre-combustion capture has a considerably different cost structure to the big steam turbine based plant. The costs of the base plant is considerably higher largely because of the high cost of the gasifier and gas clean-up equipment and the costs of integrating the processes to improve plant conversion efficiency. The direct costs of the capture equipment are much less than for PCC and OCC, with the main equipment being a water shift reactor to convert CO into CO_2. We estimate the total direct costs to be around £250/kW. The indirect costs are closer to those for the other applications, as the high cost of the host plant broadly offsets a slightly lower energy penalty. As with PCC, this energy penalty is split roughly equally between the thermal and the auxiliary load penalty. Overall, the costs for IGCC with CC work out at just above the level for super critical coal with PCC. We have not considered here the option of replacing the CCGT component of the IGCC with a fuel cell, which is now an option being considered by some developers (such as Hatfield project in the UK).

Table 3.37 shows our indicative capital cost build-up for oxy combustion and IGCC on coal with carbon capture for a newbuild plant ordered today.

The estimates made here refer to CC plant applied to new constructions, however its is likely that the costs of retrofitting a “capture ready” coal plant would be very close to those for an integrated construction. Most of the base plant costs would be the same, although the pre-development and licensing costs and balance of plant costs are likely to be a little higher for the retrofit option, as costs will not be shared with the host plant. We are assuming old coal plant would not be retrofitted with CC largely since the base plant is life expired, with the notable exception of one or possibly two short life demonstration plants. For these plants the retrofit comes at considerable premium, given the complication of integrating the capture plant.

Table 3.36: Indicative current capital cost build up for Oxy combustion and IGCC with carbon capture

Oxy combustion capture on super critical coal boiler	£/kW	% of total capex
- Site preparation and licensing	45	2%
- Air Separation unit	600	22%
- Separator`	85	3%
- Compression	105	4%
- CC BOP	70	3%
Total direct costs	905	33%
Indirect costs - Host plant compensation	256	9%
Base power plant	1600	58%
Total costs	**2761**	**100%**
IGCC – Pre-combustion capture	**£/kW**	**% of total capex**
- Site preparation and licensing	19	1%
- Water shift	111	4%
- GT conversion	31	1%
- Compression	71	3%
- CC BOP	20	1%
Total direct costs	253	10%
Indirect costs - Host plant compensation	229	9%
Base power plant	2086	81%
Total	**2568**	**100%**

Indirect costs include on the thermal penalty not the extra auxiliary load. Costs include a market congestion premium of 11% and 9% respectively for oxy and IGCC.

Source: Mott MacDonald estimates

3.10.3 Carbon capture on CCGT

3.10.3.1 Current position

For CCGT plants the realistic options for CCS are post combustion and pre-combustion capture. Oxy combustion is not possible at present as the combustion temperature for natural gas in oxygen is far too high for current technology gas turbines. Discussions with OEMs suggest that for the foreseeable future there is no interest in developing radically new GT designs able to handle gas in high oxygen mixes, which suggests that oxy combustion with gas is unlikely to be viable.

Both direct and indirect costs of CCS are lower for gas compared to coal, though the difference is greater for indirect costs. Lower indirect costs reflect the higher base efficiency of CCGTs and the lower percentage point thermal penalty and the much lower specific capex cost of CCGT versus coal plant. The lower direct costs reflect the lower tonnage of CO_2 to be captured per kWh, although the low CO_2 concentration means direct cost per tCO_2 removed should be higher than for coal.

Table 3.37 shows our estimated build up of the capital costs of post combustion capture on a new CCGT assumed to be ordered today. The total direct cost of the CC is seen to be almost as much as the cost of the host plant at £480/kW versus £515/kW. About half the direct cost is accounted for by the exhaust section, which includes the main absorber where the solvent is reacted with the flue gases. The next biggest item is the compression stage, which accounts for a quarter. The indirect costs (relating to the thermal penalty) are small, at just £31/kW, which reflects the modest energy penalty and the low cost of the host plant. As with the coal-CC estimates this price includes an estimate for the mark-up arising from current supply chain bottlenecks, though this is small for gas-CC at about 8%.

Cost estimates for CC on gas are probably less reliable than for coal plant given the limited emphasis on CC on gas fired plant and the smaller share of the host plant.

Our view is that the costs of pre-combustion capture are likely to be close to those for post combustion. Gas reformation[39] is thought to offer lower direct costs than post-combustion capture, however it presents considerable additional challenges in terms of combustion modification, as GTs need to be configured to run on hydrogen rich mixtures.

Table 3.37: Indicative current capital costs for post combustion capture fitted to a new CCGT

Cost component	£/kW installed	% share of total plant costs	% share of CC costs
- Site preparation and licensing	30	3%	6%
- Exhaust section	240	23%	47%
- Circulation/ Stripper	50	5%	10%
- Compression	120	12%	23%
- Balance of capture plant	40	4%	8%
Direct CC costs	480	47%	94%
Host plant compensation*	31	3%	6%
Total CC costs*	511	50%	100%
Base power plant	515	50%	-
Total	1026	100%	-

* includes only thermal penalty not extra aux. load
Costs include a market congestion premium (of about 8%).

Source: Mott MacDonald estimates

As with coal CC, the costs of retrofitting are likely to be close to those for a integrated newbuild construction, assuming the plant is designed as capture ready. However, the younger vintage of CCGT stations, means that there is a more plausible case for retrofitting these stations, than the UK's legacy coal stations. In this case, the retrofit premium could be more significant. However, for cases modelled in this study, we have only considered retrofits on latest generation "capture ready" plant.

[39] Steam methane reforming is mature established technology for industrial hydrogen production – which probably several 10GWs of equivalent capacity worldwide.

3.10.3.2 Outlook for reductions

Given the very early stage of CC technology there is scope for potentially large cost reductions. However, there is also a significant risk that out-turn costs for the initial full scale CCS may be more than our estimates.

There are a number of grounds for optimism in medium to long term trends.

All of the options should see cost reductions arising from improved system integration and construction sequencing, which may be learned from experience even on different options. This will depend on the level of deployment and extent to which efforts are made to share experience between companies and jurisdictions.

For post combustion capture, there is the potential for advances in solvent and reagent chemistry that will reduce requirements for large/ sophisticated vessels, and also the energy penalty (in terms of auxiliary power load and thermal losses). There is also the potential for design changes which reduce the cost of equipment (material advances, easier to build vessels, etc).

Oxy combustion is likely to benefit from advances in the application of non-cryogenic air separation technology, based on the application of advanced membranes. This could both reduce direct process equipment capex and the energy penalty (and therefore indirect costs).

Moving to higher steam conditions of ultra critical coal plants raises the base plant efficiency and so reduces the CO_2 generated per MWh. This reduces the scale of capture equipment and also the energy penalty as a percentage, however this benefit will be partly offset by the increased capex costs associated with ultra super critical versus a normal supercritical plant. Even so, in the longer term this should provide a downward pressure for the PC options (post combustion and oxy combustion).

Pre-combustion capture from IGCC and CCGT using gas reformation could benefit from the advances in chemistry applied in post combustion. The IGCC route will however require significant advances in the underlying IGCC technologies. There are at least three leading black fuel gasification approaches (based on whether the process uses air/oxygen and the fuel feed is wet or dry), however all face the common challenge of providing a feed gas to the GT without incurring a large energy penalty and without compromising reliability.

Although there is currently much less emphasis on CCS on gas plant versus coal[40], it is our view that much of the process design for post combustion capture plant could be applied to CCGT, so that CCS on gas could broadly keep pace with developments in coal. In the long run, though there is a reasonable chance that oxy combustion will provide the least cost option for coal CC assuming that the promised developments in advanced membranes lead to substantial reductions in ASU capex and energy penalties. IGCC offers the very long term prospect of even deeper cost reductions, given it is able to access the efficiency and capex advantages of GT technology, but this will require a breakthrough in extracting a useable gas from coal while capturing the carbon, perhaps through some new biotech process.

[40] The CCC has long advocated that gas CCS should be considered, while in 2010 the government also decided to allow gas CCS in the demonstration competition.

Making cost estimates based on a bottom-up engineering approach results in huge variation of costs, as one needs to guess the extent of savings in component costs, savings from integration benefits, extent of economies of scale, supply chain improvements and energy penalties.

Table 3.38: Projected capital costs of post combustion capture on a newbuild coal plant ordered in 2020 and 2040

	Installed capital costs: £/kW				
Cost component	2011	2020	2040	% of 2011 costs in 2020	% of 2011 costs in 2040
Site preparation and licensing	60	46	38	77%	64%
Exhaust section	450	309	222	69%	49%
Circulation/ Stripper	100	69	49	69%	49%
Compression	180	131	108	73%	60%
Balance of capture plant	75	52	41	69%	54%
Direct CC costs	865	606	459	70%	53%
Host plant compensation*	256	162	109	63%	42%
Total CC costs*	1121	769	567	69%	51%
Base power plant	1600	1215	1074	76%	67%
Total	2721	1984	1641	73%	60%

* includes only thermal penalty not extra aux. load. Note 2011 figure includes a market congestion premium, while figures for 2020 and 2040 do not.

Source: Mott MacDonald estimates

Table 3.39: Projected capital costs for post combustion capture on a newbuild CCGT ordered in 2020 and 2040

	2011	2020	2040	% of 2011 costs in 2020	% of 2011 costs in 2040
Site preparation and licensing	30	27	24	89%	81%
Exhaust section	240	172	130	72%	54%
Circulation/ Stripper	50	36	31	72%	63%
Compression	120	101	78	84%	65%
Balance of capture plant	40	33	29	83%	72%
Direct CC costs	480	368	292	77%	61%
Host plant compensation*	31	25	13	80%	41%
Total CC costs*	511	393	305	77%	60%
Base power plant	515	474	436	92%	85%
Total	1026	867	741	84%	72%

* includes only thermal penalty not extra aux. load. Note 2011 figure includes a market congestion premium, while figures for 2020 and 2040 do not.

Source: Mott MacDonald estimates

The extent of cost reduction will be linked to the rate of deployment, with larger saving under high deployment scenarios. However, our view is that there should be considerable savings over the next decade given the diversity of commercial demonstration projects and the collaborative approach of the industry which promises to bring benefits in system integration and installation procedures. This is expected to lead to significant reduction in direct capital costs by 2020. This is despite our expectation of a slower roll out of capacity than the IEA and the industry associations are projecting.

In the longer term, our engineering assessment suggests the application of new technologies should bring further reductions in direct costs and also energy penalties, especially under higher deployment scenarios.

Table 3.38 shows the projected capital costs for coal with PCC for 2020 and 2040 under the MML base case. This shows 30% fall in total CC costs by 2020 and 50% reduction by 2040 versus current (hypothetical) levels. The indirect costs are seen to fall more than direct costs, largely as the energy penalty is projected to fall. Indirect costs fall almost 60% by 2040 versus 2011, while direct costs fall 47%. The base power plant cost (the largest item) falls by 33% versus the current level, however a little over half this reduction is accounted for by the elimination of market congestion premium. Overall, the capital cost of coal with PCC reduces to just under £2000/kW by 2020 and about £1640/kW in 2040 – the latter representing a 40% reduction versus 2011's level.

The costs of coal generation with oxy combustion capture are projected to follow a similar pattern, although here there is great uncertainty about the costs of the largest CC element, the ASU. Since the indirect CC costs, in terms of thermal penalty are small, these are not significant for OCC. However, we project a significant reduction in auxiliary load, but this is not reflected in the capital cost evolution, though it will be picked up in the levelised costs. The base power plant costs are clearly the same as in the PCC case.

IGCC costs are also projected to fall, however, there is probably more uncertainty attached to these. Black fuel gasification technology is now well established, largely on the back of the refining sector, however, the treatment of gases to make clean GT grade gas and integration of the gasifier/ clean-up process with the power plant has proven complicated and cost reductions have come only slowly to date. Our central view is that IGCC costs will fall broadly in line with big coal steam plant, despite the lower maturity of the technology. This reflects the lower rate of deployment and the lower current mark up, due to supply chain constraints for IGCC versus super-critical coal plant.

Table 3.39 shows the projected capital cost evolution to 2040 for CCGT fitted with PCC under the MML base case. Direct CC costs are projected to fall by around 40% by 2040, led by a substantial reduction in the exhaustion section costs (smaller and cheap absorbers etc). Indirect costs, already small, as in the coal-PCC case show the greatest reduction as thermal penalties are substantially cut. In contrast with coal, the base power plant sees a small reduction, 15% by 2040, with the result that the capex penalty from fitting CCS is reduced from roughly 100% currently to 70% in 2040.

It is worth mentioning that the capture plant should be able to be upgraded during the life of the base plant, for example by using new agents etc, however the scope for cost reduction from such modifications will be much less than installing new, because of the initial plant configuration and sizing is unlikely to be optimal.

Similar cost reductions are projected for gas with pre-combustion capture.

All the above capital cost estimates are based on an engineering cost assessment. It is worth briefly commenting on the capital cost projections made using a learning curve approach which give cost reductions of a similar magnitude described above. As mentioned in Chapter 2, to apply this approach in the absence of a significant industry track record, requires that appropriate comparator technology is found. Our view is that the appropriate technologies are flue gas desulphurisation (FGD) and oil refining, for which learning rates have been observed at about 10% per doubling of deployed capacity.

The problem then is to define the technology category and the starting level. Our view is that ideally we should differentiate between post combustion capture, oxy combustion, pre-combustion on coal and pre-combustion on gas. However, in practice it is likely that there will be some learning across technologies and it is anyway unrealistic to make credible forecasts for the split of CC technologies over 20-30 years. We therefore split our projection only between coal and gas CCS. If we assume a starting level of 1GW for each, then the Table 3.40 shows cost reduction through learning at different global deployment levels. In broad terms we might expect 2-4 doublings by 2020 and 4-8 by 2040, which would give cost reductions of a similar magnitude as what we are projecting in the engineering assessment.

Table 3.40: Projected cost reductions in relation to deployment doublings based a 10% learning rate

No. of doublings	GW deployed	Cost as ratio of current	% reduction on current
3	8	0.73	27%
4	16	0.66	34%
6	64	0.53	47%
8	256	0.43	57%

Source: Mott MacDonald

Outlook for levelised costs

Taking the above capital cost assessments, our central case projections for other plant cost and performance parameters and Oxera's central discount rate case (outlined in Chapter 6) gives an indicative current levelised cost range for coal and gas CCS of £145-152/MWh and £100-105/MWh, respectively. This includes the market congestion premium on the capex, which is noticeably higher on coal. 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 gives a levelised cost in 2040 for coal-CCS and gas-CCS of £85-119/MWh and £91-98/MWh, respectively. Note this range is only considering capex uncertainty. 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.

3.11 Unknown unknowns

One thing is for certain, is that there will be uncertainties. Unknown unknowns are a profound form of uncertainty and in principle can not be defined. So what follows here is a brief note on the known unknowns: things that we are aware of but are extremely uncertain.

We have considered only four technologies; two of which are almost certainly (though not definitely) non-starters, in that they appear to contradict known science and two others, which are scientifically proven, though still presents a huge engineering challenge to making them economically feasible. They have been chosen purely as illustrative rather than indicating in anyway our endorsement. There many other nascent technologies that could have been equally selected. They never the less provide an indication of the potential disruptive technologies, that could begin to affect global energy systems within the next two decades.

3.11.1 Cold Fusion

As recently as January 2011 an idea from science-fiction literature has yet again captured public imagination with sensational claims about energy production. The culprit, Cold Fusion or LENR – Low Energy Nuclear Reaction, was given a public demonstration conducted by Italian scientists. The idea of nuclear fusion has been around for many decades. It relates to unknown processes offered to explain a group of disputed experimental results related to electrochemical reactions first introduced by Martin Fleischmann and Stanley Pons in the 1989.

The claim, historical and the present one, is a technology that offers a boundless source of clean energy. Hypothetically, the process involves fusing two smaller atomic nuclei together into a larger nucleus, a process accompanied by huge energy dissipation. The newest device – nickel-hydrogen fusion reactor is said to rely on the ability of nickel to absorb hydrogen, a process accompanied by large heat release. Nickel and hydrogen are the consumables in this technology, but their use is said to be very low. The input/output energy power gain is claimed to about 1:30.

The by-products of the reaction are copper and certain amounts of radiation, which vanishes soon after termination of the process. Self-sustained reactor is claimed to be in operation for two years (undisclosed location) and commercial megawatt-rated designs of the product are expected to reach market in 2-3 years. However, the science behind this technology is not yet understood, which undermines the legitimacy of this venture. The evidence on how the process works presented in a research paper has been rejected by all reputable journals. A similar fate met the patent application. The scientific consensus on cold fusion is that it’s theoretically implausible. Lack of publicly verifiable pilot projects commands a great deal of scepticism. Previous claims of successful cold fusion projects have all been eventually refuted. Taken together existing evidence does not allow any confidence in this technology becoming substitute for conventional power sources in the near term.

3.11.2 Blacklight Power

Blacklight power is yet another technology that promises to provide for the world’s energy requirements in a sustainable manner, emission free and at an affordable price. Blacklight process relies on an alleged chemical process of releasing latent energy of the hydrogen atom. In the unrecognized process, atomic hydrogen is reacted with a catalyst, and energy is released as the electrons of atomic hydrogen are induced by the catalyst to undergo transitions to lower energy levels to form lower-energy hydrogen atoms called hydrinos (whose existence is refuted by the scientific community). The energy release is thought intermediate between conventional chemical and nuclear energies. The net energy released is claimed to be over one hundred times that of combustion with power densities like those of fossil fuel and nuclear power plants. Generated surface heat, which is compared to existing commercial fire boxes in natural gas and coal-fired plants, can be coupled with existing heat-to-electric technologies such as steam turbine to generate electricity. The hydrogen fuel is said to be obtained by diverting a fraction of the output energy of the process to power the electrolysis of water into its elemental constituents. With water as the fuel the method seems to offer, in essence, free energy.

The problem is, Blacklight Power still needs to convince a very sceptical scientific community about the existence of hydrinos and the theoretical legitimacy of the alleged hydrogen-to-hydrino process. Despite a ten year history the company still has not produced a prototype of any size and proved it to reputable scientists. Hydrinos described by the inventors violate the basic laws of quantum physics -- the rules of how atoms behave. The claim that this technology will present an economically viable and environmentally benign alternate to meet global energy needs seems very far fetched. Nevertheless, some scientists assert successful validation of the process. On the whole, however, there is overwhelming evidence that suggests dismissal of this technology as a panacea to the world's energy problem.

3.11.3 Air scrubbers

Industrial scale air scrubbers that capture carbon dioxide from ambient air present a potential alternative to conventional CCS which captures CO_2 from individual power stations. They both employ mass separating agents that extract and purify CO_2 allowing its capture and storage. Due to much lower concentration of the gas in ambient air (~400ppm) as opposed to 5-15% in flue gases air capture installations are expected to be larger than CCS ones. The corollary of this is that capital costs and energy consumption would be expected to be much higher than for CC integrated with power generation. That said, some of the processes under development claim to capture CO_2 at much higher rates through various concentration techniques.

Air scrubbers offer the advantage of mitigating emissions from all sources including mobile sources (i.e. aviation and transport) and offering flexibility as to plant localization. Furthermore since air scrubber could be mass produced as identical copies there would be great potential for cost reduction through mass production, something that is extremely unlikely for CC on power plant.

Energy intensity of the air purification process is common to both technologies, but recent innovations in the field promise more economical solutions in the future. A number of technologies utilise power plant waste heat to purify the adsorbent materials that are used to trap carbon dioxide. Traditionally, amine sorbents are regenerated through heat in the presence of a flowing gas such as nitrogen and helium, which necessitates further energy intensive processes to remove them from the resulting mixture. Global Thermostat put forward a new approach where low temperature steam (abundant in most coal-burning facilities) is used to extract trapped gas from an innovative sorbent. Induced water condensation through intensive pressurisation creates a clean stream of CO_2 suitable for storage. Using low temperature steam (105^{o} C) is claimed to mean only a small energy penalty on the mother plant. Even if energy penalties remain significant, some air scrubber developers are talking of integrating their scrubber with solar generation plant to provide the energy. In an elegant closing of the loop, they are also proposing to recycle the captured CO_2 as a feedstock for new solar derived fuels.

However, there is no available evidence on sorbent durability and the CO_2 removal efficiency. Pilot-scale separation facilities are already in operation, but again no detailed reports on their performance are obtainable. The main difficulty is thought to lie in developing sorbent materials that will withstand thousands of purification cycles making them commercially practical. Here again, advances in materials science may deliver suitable materials.

The field of air capture is still in its infancy, but with additional research into solvents, adsorbents, and membranes for CO_2 capture low-cost processes may emerge and contest present technologies of carbon capture on power plants.

3.11.4 Nuclear (hot) fusion

Nuclear fusion has been demonstrated at a pilot scale albeit on an extremely short duration basis, using both a plasma (so-called Tokomak) and a laser pulse (often called) impact approach. The processes are consistent with current scientific theories and work is underway to extend the reactions and measure net energy yields. There is nothing in the physics that says that one or other of these approaches should not yield a net energy yield, but no experiments to date have generated a positive yield.

Fusion is seen largely as an engineering challenge, whereby a small group of developers are testing almost through trial and error different configurations for containment/ laser types and fuel. Such research has been underway for several decades and progress has been slow. A BBC Horizon straw poll of people in the fusion research community indicated few expected a viable and sustained fusion process with a positive energy yield would be available before 2030. And these tend to be the optimists.

Even assuming the technology can be made to work, it would require probably a very substantial positive energy yield to offset the expected high capital costs, associated with high energy physics apparatus. On these conditions, though it would be truly transformational.

4. Deployment Scenarios

4.1 Introduction

In this section we outline our assumptions regarding the deployment of different technologies and how this translates into cost reductions through learning under our three archetypal scenarios. First we consider the deployment rates, then we introduce the three scenarios and finally we conclude with a review of the implied cost reductions through learning using learning rates take from the literature.

4.2 Technology deployment assumptions

Projecting out to 2050 there is a huge range for the potential level of cumulative deployed capacity for all the electricity generation technologies considered in this report. Take CCS on coal for example. The plausible range could be anywhere from just a few GW to thousands of GW, depending on one's assumptions about technology advances, availability of coal and sequestration sites, public attitudes to risk, etc. The range is less, but still large if we define the range as the difference between high and low cases in number of doublings from current levels, especially if the initial level is very low. For a number of technologies there is no commercial scale deployment, so the doublings are meaningless. As mentioned earlier, for technologies with no significant deployment, we therefore need to set a starting level that represents a level of deployment associated with a series of early commercial projects.

We have considered deployment both at a global level and at UK level, in order that we can explore the impact of changing the weighting of the learning from UK and global deployment.

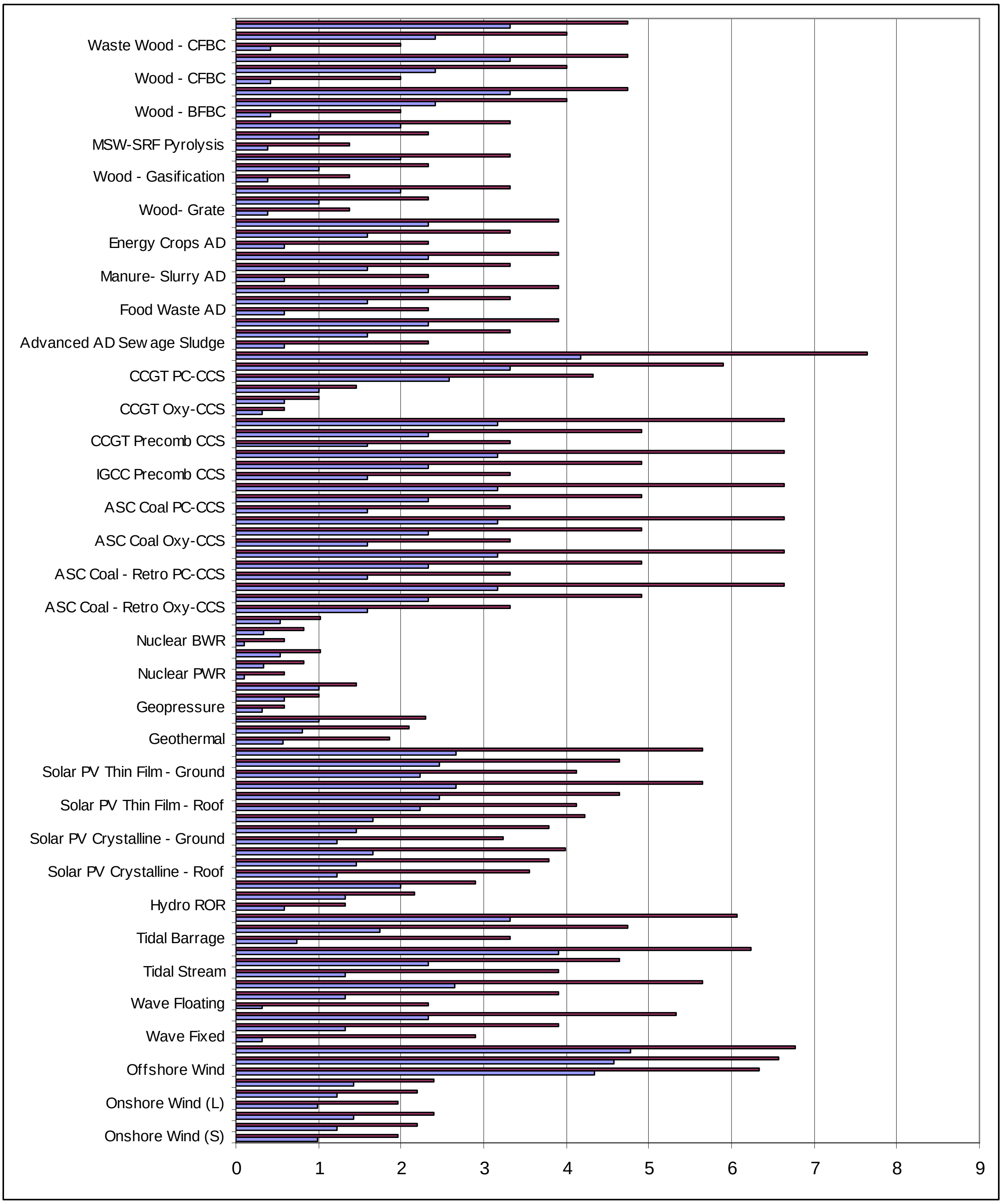
Figures for global deployment have been guided by the IEA's 2010 World Energy Outlook although some of these have been adjusted to provide an increased range. UK figures have been based on various sources such as the National Renewable Energy Action Plan (NREAP[41]) and the 2050 Pathways[42]. In both cases we have aggregated across technologies to make technology groups, otherwise the range would be even greater. For example, all CCS coal technologies are grouped together as are solar PV, nuclear and bio-methane and woody biomass. The detailed figures are shown in Annex A. This annex also shows the starting levels for each technology.

The range of doublings that is generated from these assumptions is shown in **Error! Reference source not found.** and Table 4.1. This shows doublings at the low end of less than one for nuclear for example, in a case where Europe and America abandon their programmes, to 8-9 for some emergent and potentially widely deployed technologies (such as CCS on coal and offshore wind). Solar PV's doubling rate is not the highest given there is already a significant base level of deployment.

[41] National Renewable action Plan for the UK, DECC, 2010

[42] 2050 Pathways Analysis, July 2010, HMG.

Figure 4.1: Cumulative deployment doubling rates by 2020 and 2040 under low, central and high deployment cases



Source: Mott MacDonald estimates based on literature review

Table 4.1: Cumulative deployment doubling rates by 2020 and 2040 (under low, central and high cases)

	UK doublings		Global doublings	
	2020	2040	2020	2040
Onshore Wind (S)	1.66	2.09	0.99	1.96
	1.90	2.32	1.22	2.20
	2.10	2.52	1.43	2.40
Onshore Wind (L)	1.66	2.09	0.99	1.96
	1.90	2.32	1.22	2.20
	2.10	2.52	1.43	2.40
Offshore Wind	2.98	3.60	4.33	6.33
	3.22	3.84	4.57	6.57
	3.42	4.04	4.77	6.77
Wave Fixed	0.26	1.00	0.32	2.91
	1.00	2.00	1.32	3.91
	1.32	3.17	2.32	5.32
Wave Floating	0.26	0.68	0.32	2.32
	1.00	1.58	1.32	3.91
	2.00	3.32	2.64	5.64
Tidal Stream	1.00	2.32	1.32	3.91
	1.58	3.91	2.32	4.64
	2.32	4.91	3.91	6.23
Tidal Barrage	1.00	3.32	0.74	3.32
	1.58	5.64	1.74	4.74
	2.32	6.49	3.32	6.06
Hydro ROR	0.58	1.00	0.58	1.32
	1.58	2.32	1.32	2.17
	2.00	3.00	2.00	2.91
Solar PV Crystalline - Roof	2.85	5.24	1.22	3.55
	3.09	5.48	1.46	3.79
	3.29	5.68	1.66	3.99
Solar PV Crystalline - Ground	2.85	5.24	1.22	3.23
	3.09	5.48	1.46	3.79
	3.29	5.68	1.66	4.23
Solar PV Thin Film - Roof	2.09	5.09	2.22	4.13
	2.32	5.32	2.46	4.64
	2.52	5.52	2.66	5.64
Solar PV Thin Film - Ground	2.09	5.09	2.22	4.13
	2.32	5.32	2.46	4.64
	2.52	5.52	2.66	5.64
Geothermal	-0.23	3.09	0.57	1.85
	0.00	3.32	0.81	2.09
	0.20	3.52	1.01	2.29
Nuclear PWR	0.32	1.23	0.09	0.59
	0.55	1.46	0.33	0.82
	0.76	1.66	0.53	1.02

	UK doublings		Global doublings	
Nuclear BWR	0.00	0.00	0.09	0.59
	0.00	0.00	0.33	0.82
	0.00	0.00	0.53	1.02
ASC Coal Oxy-CCS	1.58	2.58	1.58	3.32
	2.58	4.91	2.32	4.91
	3.32	5.91	3.17	6.64
ASC Coal PC-CCS	1.58	2.58	1.58	3.32
	2.58	4.91	2.32	4.91
	3.32	5.91	3.17	6.64
IGCC Precomb CCS	1.58	2.58	1.58	3.32
	2.58	4.91	2.32	4.91
	3.32	5.91	3.17	6.64
CCGT Precomb CCS	1.58	2.58	1.58	3.32
	2.58	4.91	2.32	4.91
	3.32	5.91	3.17	6.64
CCGT PC-CCS	1.58	2.58	2.58	4.32
	2.58	4.91	3.32	5.91
	3.32	5.91	4.17	7.64
Advanced AD Sewage Sludge	0.26	2.32	0.58	2.32
	1.58	2.91	1.58	3.32
	2.32	3.32	2.32	3.91
Food Waste AD	0.26	2.32	0.58	2.32
	1.58	2.91	1.58	3.32
	2.32	3.32	2.32	3.91
Manure- Slurry AD	0.26	2.32	0.58	2.32
	1.58	2.91	1.58	3.32
	2.32	3.32	2.32	3.91
Energy Crops AD	0.26	2.32	0.58	2.32
	1.58	2.91	1.58	3.32
	2.32	3.32	2.32	3.91
Wood- Grate	0.26	0.68	0.38	1.38
	1.00	1.49	1.00	2.32
	1.32	1.81	2.00	3.32
Wood - Gasification	0.26	0.68	0.38	1.38
	1.00	1.49	1.00	2.32
	1.32	1.81	2.00	3.32
MSW-SRF Pyrolysis	0.26	0.68	0.38	1.38
	1.00	1.49	1.00	2.32
	1.32	1.81	2.00	3.32
Wood – BFBC	1.00	1.74	0.42	2.00
	2.74	4.32	2.42	4.00
	3.74	5.32	3.32	4.74
Wood – CFBC	1.00	1.74	0.42	2.00
	2.74	4.32	2.42	4.00

	UK doublings		Global doublings	
	3.74	5.32	3.32	4.74
Waste Wood – Grate	1.00	1.74	0.42	2.00
	2.74	4.32	2.42	4.00
	3.74	5.32	3.32	4.74

Source: Mott MacDonald estimates based on literature review

4.3 Archetypal scenarios

In order to provide a sensible narrowing down of the range of uncertainties, we have produced three archetypal scenarios which combine different assumptions about the mix of deployment and support across technologies. The alternative of combining all the high, base or low cases across technologies would have given a much wider range and also would probably not represent plausible scenarios.

The three scenarios are each described below:

4.3.1 Balanced efforts scenario

This scenario assumes that there is a broadly based energy strategy and public acceptability of deployment of all the main categories of low carbon generation technologies including nuclear, renewables and CCS on both coal and gas. No particular technology category is pushed aggressively, although all the supply side options are probably pushed more than the demand side measures. However, the overall level of support is such that this scenario is assumed to achieve considerable decarbonisation of the power sector by 2050.

4.3.2 High renewable scenario

Under this scenario there is a substantial support for all the renewables technologies and for demand mitigation. At the same time there is no significant policy support for nuclear and CCS and indeed it is likely that both these technology groups would be prohibited in many jurisdictions (especially in the OECD). We have assumed that CCS on gas will have some support, on the grounds that in some jurisdictions there may be a need for a certain amount of flexible desptachable back-up generation. Except for this last inclusion of support for CCS-gas, this scenario is close to the Greenpeace scenario as outlined in the "Battle of Grids" paper (2011).

4.3.3 Least cost scenario

This scenario represents a case where public policy focuses on achieving decarbonisation at least cost. This means that support and developer interests follows those technologies which are closest to market feasibility. This suggests that onshore wind, mini hydro and the lower cost bio-energy options would be the favoured renewable options, while nuclear and CCS on gas would also be favoured. Offshore wind and the marine renewables would see little support, as would CCS on coal. Solar PV is assumed to be supported in applications where it is integrated into building design (roof mounted) but not in ground mounted applications, although there would in practice be spill-over learning effects to ground mounted schemes. As in the high renewables scenario, there would be an assumption of considerable emphasis on demand mitigation, through mandatory codes etc (although less emphasis on exhortation versus the more "green" renewables scenario).

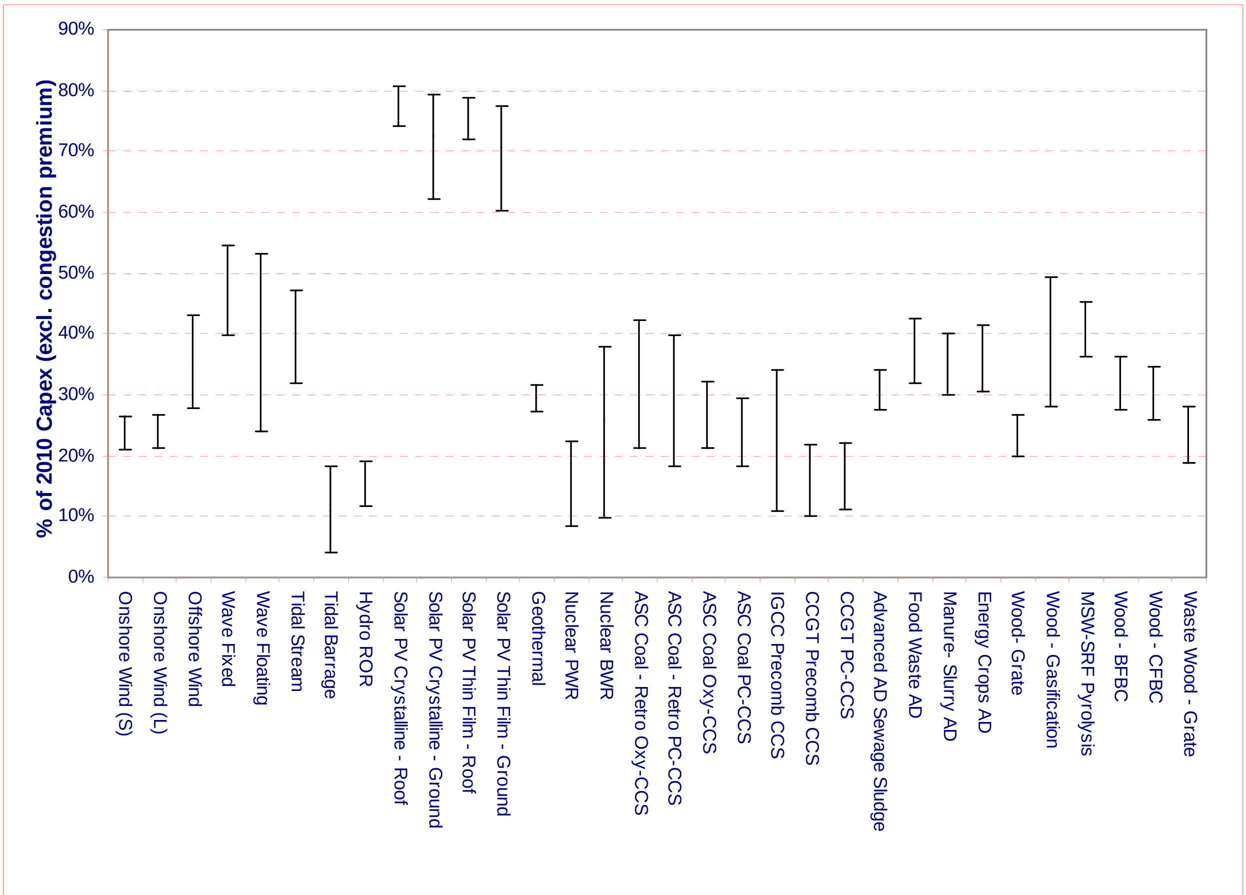
The deployment projections for each scenario are outlined in Annex A.

It is worth noting that all three of these scenarios assume a similar and substantial rate of decarbonisation both in the UK and global power sectors. In this sense all three scenarios represent the achievement of the UK government's and IEA/EU's aspirations regarding decarbonisation by 2050. We have not included in this analysis a "trends continued" or "business as usual" case. Such a scenario would have lower deployment rates across the board, although there would still be some advances driven by current policy support measures.

4.4 Cost reductions by learning

Combining the deployment doublings with the learning rates outlined in Chapter 2 (see Figure 2.1) shows the cumulative capital cost reductions by 2040 for the three scenarios. These are shown graphically in Figure 4.2 (and in tables in Annex B). These cost reductions are applied to current capital costs **after** they have been adjusted for any market congestion premiums (or discounts).

Figure 4.2: Capital cost reductions by 2040 under the three archetypal scenarios using the learning curve approach

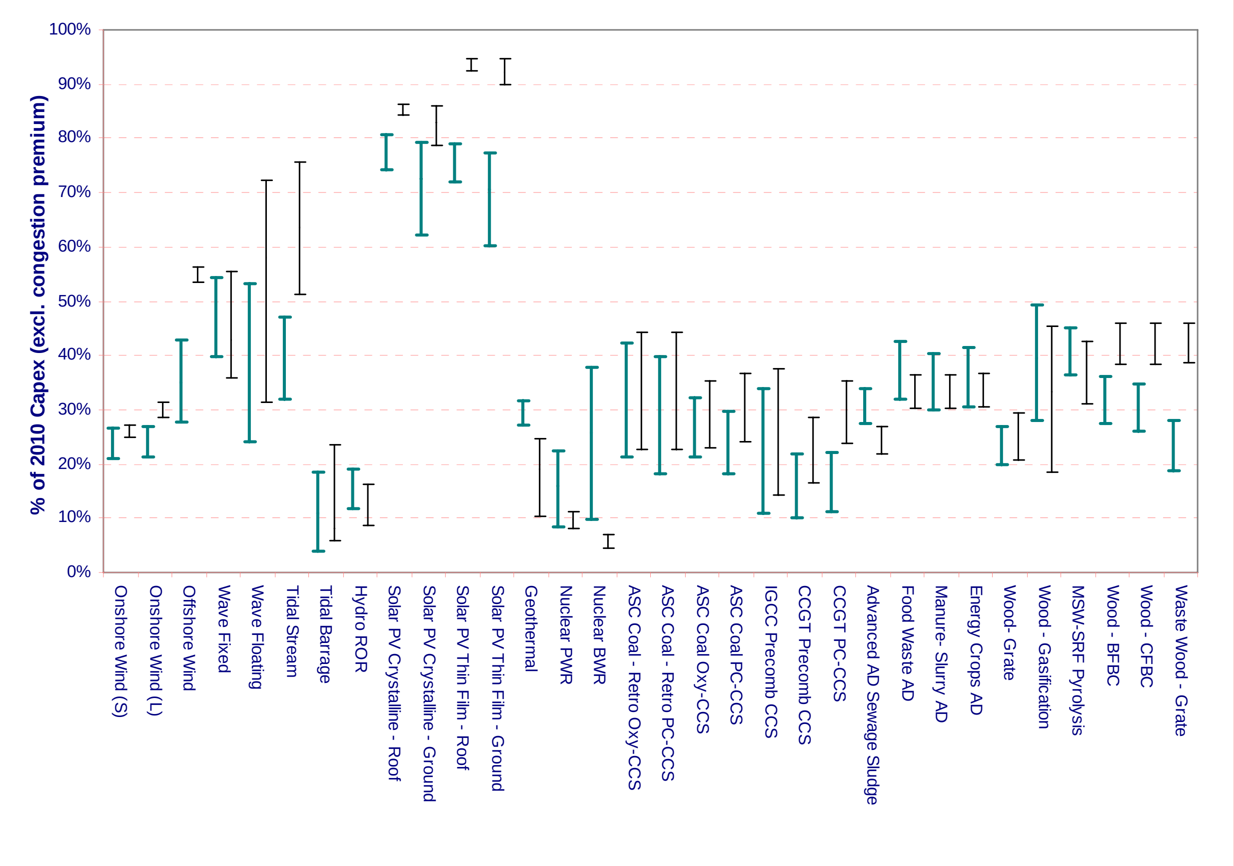


Source: Mott MacDonald

This shows the dramatic expected capex reduction for solar PV, strong performance of offshore wind and CCS but limited progress for nuclear. This partly reflects the difference in numbers of doublings but also the much higher learning rates for solar PV. There are some differences between the three scenarios, with cost reductions for CCS on coal and offshore wind showing the greatest variation, while nuclear shows the little variation.

This pattern of cost reductions which derives from applying the experience curve approach can be compared with the cost reductions that are provided by our engineering cost assessment, assuming the market “congestion premiums” are stripped out. This shows a broadly similar picture of general costs reductions by technology, as is shown in Figure 4.3. The notable exceptions are for nuclear and offshore wind. For nuclear our engineering assessment sees a marked improvement versus the learning curve approach; however for offshore wind the learning curve approach provides the deeper cost reduction.

Figure 4.3: Capital cost reductions by 2040 from MML assessment versus the learning curve approach under the 3 archetypal scenarios



Source: Mott MacDonald

5. Main findings on capex cost evolution

5.1 Introduction

This chapter examines the projected evolution of the capital costs under the three archetypal scenarios using the MML engineering assessments and the learning curve approach. It then considers a number of sensitivities with regard to material costs, technological breakthroughs and impacts of competition/ outsourcing to low cost jurisdictions.

5.2 Capital cost evolution under the three archetypal scenarios

As one would expect, the three archetypal scenarios embody some significant differences between relative positions of technologies, although there is clearly not the range of potential outcomes that there could be if we considered the full range of input uncertainties. These scenarios are mainly exploring deployment uncertainties. Renewables technologies tend to fair best under the high renewable scenario, whereas nuclear and CCS are handicapped in this scenario. Under the least cost scenario, nuclear does particularly well, on the assumption that it would have been picked out as offering the potential for low cost generation in the medium term, but offshore wind does less well under this scenario (given its current levelised cost disadvantage versus nuclear). CCS technologies tend to have less of range of outcomes between the scenarios, except for IGCC based options where there is more inherent uncertainty regarding the underlying technology.

There is general agreement as to relative movements of technologies between the engineering assessment and the learning curve approach. Solar PV, wave, tidal stream and offshore wind are all projected to see the deep capex costs reductions, while onshore wind, tidal barrage and mini hydro would see the smallest improvements. Biomass technologies tend to have moderate cost reductions, with gasification (and to a lesser extent pyrolysis) expected to have the greatest potential for reduction. The main exception is nuclear, where MML's view is that there is potential scope for deep reductions, almost halving capex cost by 2040, versus a quarter at best under the learning approach. As mentioned, previously this largely reflects the low learning rates observed in the past as the nuclear industry has struggled to control costs in the face of continued regulatory/licensing changes. MML considers that procedures being put in place today could overcome this constraint and that there are precedents (outside of the UK, such as South Korea) that indicate that deep cost reductions could be achievable. The other notable exceptions are for marine renewables, but in this case the MML assessment is for a less dramatic cost reduction than the learning approach, 50-55% on current levels by 2040, versus 60-80%. There is also a significant though less marked difference for offshore wind, where MML estimates a 50% capex reduction by 2040 versus 67% reduction for the learning approach. Table 5.1 shows the projected total capex for each technology in 2040 taking the lowest outcome, expressed as a percentage of the 2011 value.

There is also general agreement between approaches on the level of uncertainty, which can be expressed as the differential between the high and low outcomes across the three archetypal scenarios. As would be expected there is greater uncertainty for the earlier stage technologies, such a marine renewables, solar PV, IGCC and biomass gasification and less for the mature technologies such as onshore wind, mini hydro and tidal barrage. There is again a difference with regard to the nuclear assessment, where MML's engineering assessment indicates considerable uncertainty (comparable with early stage technologies) while the learning curve approach does not. However, this probably reflects the fact that we have only tested here for deployment uncertainty, and have kept progress ratios constant. Table 5.2 shows the differential in 2040 capex between high and low values in 3 scenarios, expressed as percentage of the maximum.

Table 5.1: Projected capex cost in 2040 expressed as % of 2011, taking lowest outcome in scenarios

	MML estimate	Learning curve approach	Percentage point diff.
Onshore Wind (S)	72%	71%	1%
Onshore Wind (L)	71%	67%	4%
Offshore Wind	50%	38%	12%
Wave Fixed	44%	43%	1%
Wave Floating	45%	27%	19%
Tidal Stream	46%	21%	25%
Tidal Barrage	82%	76%	5%
Hydro ROR	79%	81%	-2%
Solar PV Crystalline - Roof	16%	12%	4%
Solar PV Crystalline - Ground	19%	12%	6%
Solar PV Thin Film - Roof	17%	5%	13%
Solar PV Thin Film - Ground	20%	5%	16%
Geothermal	67%	74%	-7%
Nuclear PWR	51%	74%	-23%
Nuclear BWR	54%	81%	-27%
ASC Coal Oxy-CCS	59%	56%	3%
ASC Coal PC-CCS	60%	54%	6%
IGCC Precomb CCS	62%	58%	3%
CCGT Precomb CCS	74%	67%	7%
CCGT PC-CCS	72%	60%	12%
Advanced AD Sewage Sludge	62%	68%	-7%
Food Waste AD	54%	60%	-6%
Manure- Slurry AD	56%	59%	-4%
Energy Crops AD	55%	59%	-4%
Wood- Grate	68%	66%	2%
Wood – Gasification	47%	51%	-4%
MSW-SRF Pyrolysis	51%	54%	-3%
Wood – BFBC	62%	52%	9%
Wood – CFBC	63%	52%	11%
Waste Wood – CFBC	67%	50%	17%

Source: Mott MacDonald

Table 5.2: Differential in 2040 capex between high /low values in 3 scenarios, expressed as % of maximum

	MML estimate	Learning curve approach	Percentage point diff.
Onshore Wind (S)	7%	3%	4%
Onshore Wind (L)	7%	4%	3%
Offshore Wind	21%	6%	15%
Wave Fixed	24%	31%	-6%

	MML estimate	Learning curve approach	Percentage point diff.
Wave Floating	38%	60%	-21%
Tidal Stream	22%	50%	-28%
Tidal Barrage	15%	19%	-4%
Hydro ROR	8%	8%	0%
Solar PV Crystalline - Roof	29%	11%	18%
Solar PV Crystalline - Ground	50%	34%	16%
Solar PV Thin Film - Roof	26%	30%	-4%
Solar PV Thin Film - Ground	49%	47%	2%
Geothermal	6%	16%	-10%
Nuclear PWR	33%	3%	29%
Nuclear BWR	31%	3%	29%
ASC Coal Oxy-CCS	14%	16%	-2%
ASC Coal PC-CCS	14%	16%	-3%
IGCC Precomb CCS	26%	27%	-1%
CCGT Precomb CCS	13%	15%	-2%
CCGT PC-CCS	12%	15%	-3%
Advanced AD Sewage Sludge	9%	6%	3%
Food Waste AD	16%	9%	7%
Manure- Slurry AD	15%	9%	6%
Energy Crops AD	16%	9%	7%
Wood- Grate	9%	11%	-2%
Wood – Gasification	29%	33%	-4%
MSW-SRF Pyrolysis	14%	17%	-3%
Wood – BFBC	12%	12%	0%
Wood – CFBC	12%	12%	0%
Waste Wood – CFBC	11%	12%	-1%

Source: Mott MacDonald

The following sections show the projected evolution of capital costs under the three scenarios for both the MML assessment and learning curve approaches. In addition to the features mentioned above, the main points to note are as follows:

Solar PV is projected to become the least cost of the main technologies in terms of specific capital cost per kW, some time between 2020 and 2035 in all three scenarios. The breakthrough date is earlier in the High Renewable scenario (reflecting high deployment and cost reductions) and also for the MM estimates versus those applying the literature learning rates. This could reflect perhaps a modest upper end deployment level from the IEA scenarios, as much as MM assessment that government initiatives backed up by venture capital and nanotechnology developments are likely to see a quickening in the pace of technological change.

Offshore wind sees considerable reduction in costs under most scenarios, although it is much less in the least cost scenario, where the rate of deployment is throttled back. In the balanced efforts and high renewables scenario offshore wind capital costs are projected to come down towards current onshore costs, however they retain a significant premium over onshore capex (even when adjusted for the higher energy yields).

Nuclear is projected to see gains against current levels however the extent of improvement varies considerably between scenarios and also between the MM estimates and those generated from using the literature learning rates. The extent of the difference is worth about £440/kW by 2020 and almost £900/kW by 2040. Under nuclear's most optimistic scenario nuclear becomes lower cost than all the coal-CCS options, though still more expensive than offshore wind and gas-CCS options. Under nuclear's more pessimistic outturns, it remains more expensive than all the coal-CCS options.

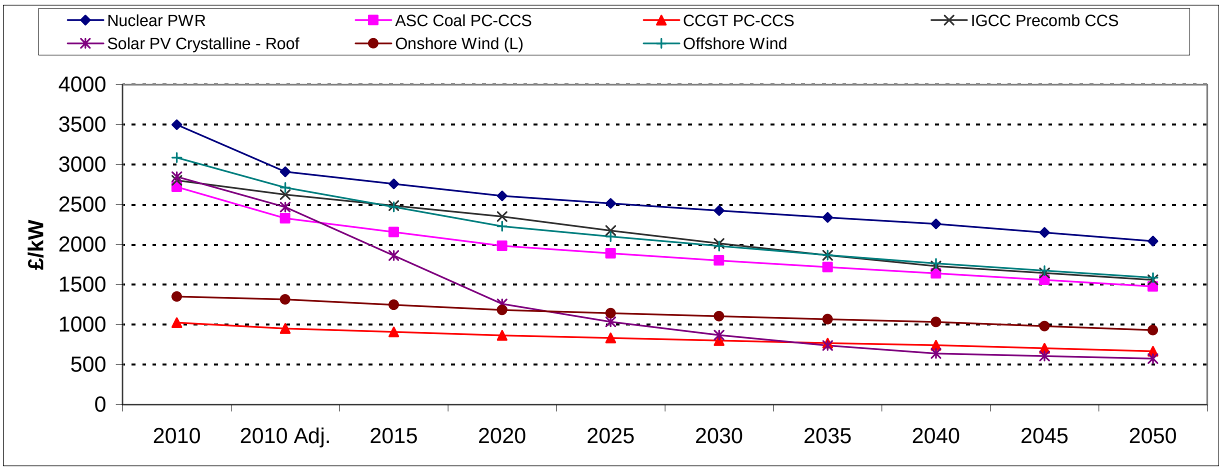
The outlook for CCS options is really split between the coal and gas, with gas-CCS (at least post and pre-combustion) both being essentially low capex options. In most cases, gas-CCS is projected to have a lower capital cost than on-shore wind. Coal-CCS has a much higher capex, coming in at a premium over gas-CCS of over £1500/kW. This reflects the much lower capital costs of CCGT plant versus big coal plant and the much reduced indirect CCS costs.

The following sections present the capital cost projections for the main low carbon generation technologies under the three scenarios in tabular and chart form. Note, that in each table and chart, the "2010 Adj." refers to the capital costs with the congestion premium/discount stripped out. The projections beyond 2040 to 2050 are made on the basis of the extrapolation of the best fit power curve between the adjusted 2010 value and estimated values for 2020 and 2040.

5.2.1 Balanced efforts scenario

Figure 5.1: Projected capital costs under the Balanced efforts scenario using MM estimates

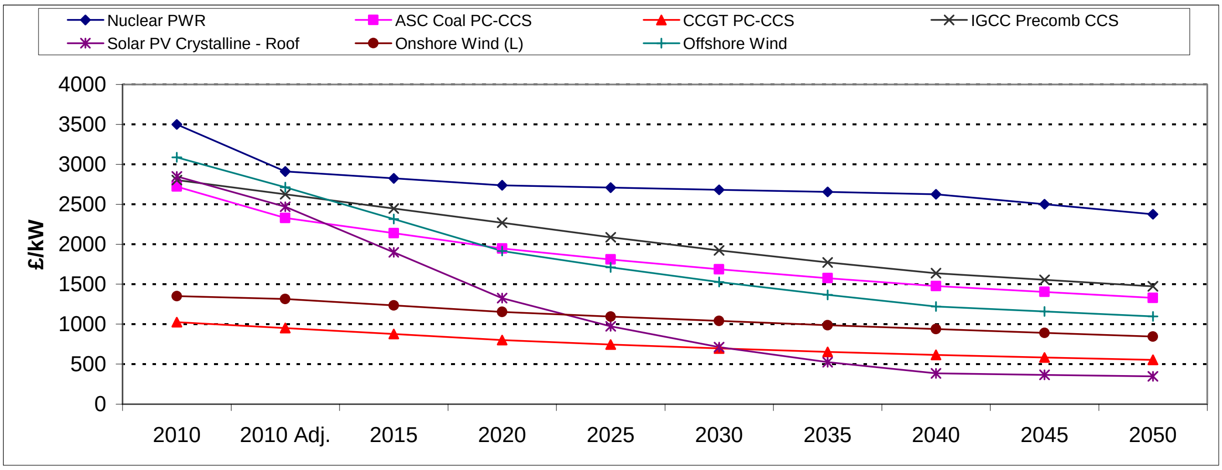
	Technology	2010	2010 Adj.	2015	2020	2025	2030	2035	2040	2045	2050
15	Nuclear PWR	3500	2910	2759	2608	2516	2426	2341	2259	2151	2044
20	ASC Coal PC-CCS	2721	2330	2157	1984	1890	1802	1719	1641	1559	1477
24	CCGT PC-CCS	1026	951	909	867	833	800	770	741	704	667
21	IGCC Precomb CCS	2803	2624	2488	2351	2176	2016	1868	1733	1646	1559
9	Solar PV Crystalline -	2850	2470	1864	1258	1035	868	739	639	607	575
2	Onshore Wind (L)	1350	1315	1249	1182	1143	1105	1069	1034	982	930
3	Offshore Wind	3088	2715	2472	2229	2102	1982	1870	1764	1676	1587



Source: Mott MacDonald

Figure 5.2: Projected capital costs under the Balanced efforts scenario using literature learning rates

	Technology	2010	2010 Adj.	2015	2020	2025	2030	2035	2040	2045	2050
15	Nuclear PWR	3500	2910	2824	2738	2709	2681	2654	2626	2501	2375
20	ASC Coal PC-CCS	2721	2330	2139	1948	1810	1686	1576	1477	1403	1330
24	CCGT PC-CCS	1026	951	876	801	746	697	654	616	585	554
21	IGCC Precomb CCS	2803	2624	2447	2270	2088	1923	1773	1637	1555	1474
9	Solar PV Crystalline -	2850	2470	1898	1326	973	714	524	385	366	346
2	Onshore Wind (L)	1350	1315	1234	1154	1096	1041	988	938	891	844
3	Offshore Wind	3088	2715	2315	1916	1711	1529	1366	1220	1159	1098

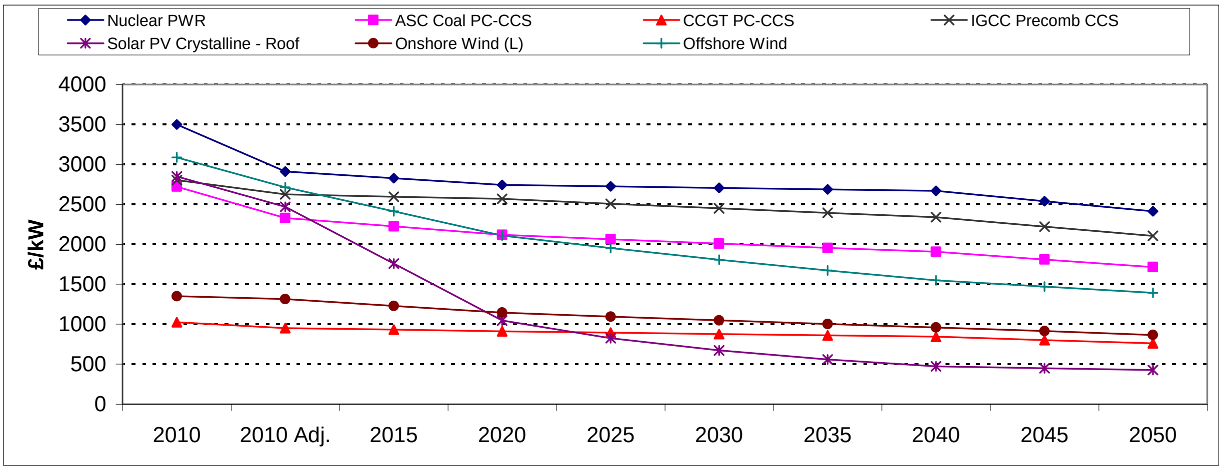


Source: Mott MacDonald

5.2.2 Renewables scenario

Figure 5.3: Projected capital costs under the High renewables scenario using MM estimates

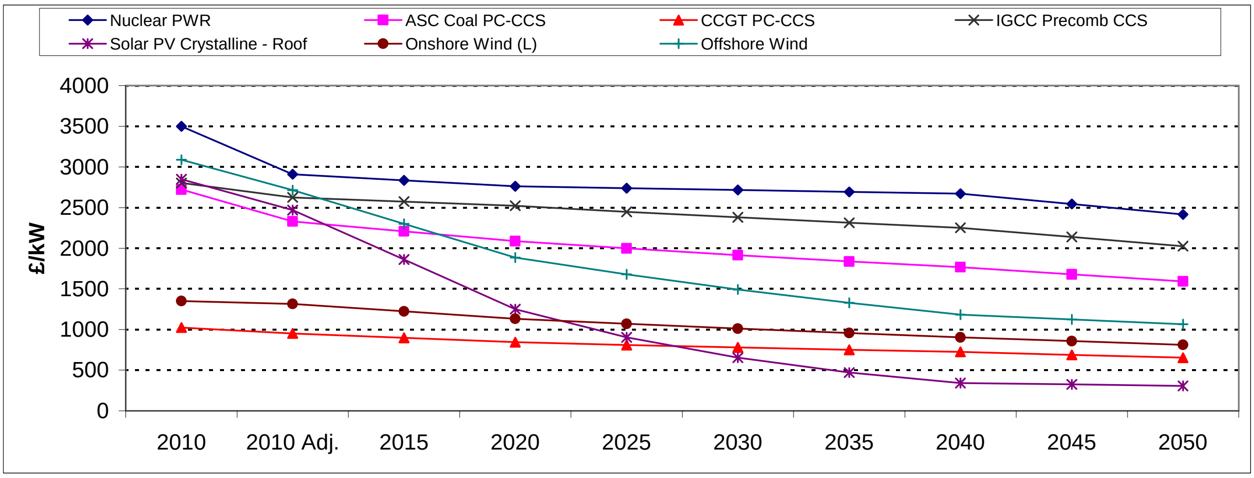
Technology	2010	2010 Adj.	2015	2020	2025	2030	2035	2040	2045	2050
15 Nuclear PWR	3500	2910	2827	2743	2724	2705	2686	2668	2540	2413
20 ASC Coal PC-CCS	2721	2330	2225	2119	2063	2009	1957	1907	1811	1716
24 CCGT PC-CCS	1026	951	932	913	895	877	861	845	802	760
21 IGCC Precomb CCS	2803	2624	2596	2568	2508	2450	2394	2339	2222	2105
9 Solar PV Crystalline -	2850	2470	1759	1048	827	672	559	474	450	427
2 Onshore Wind (L)	1350	1315	1230	1145	1096	1049	1004	961	913	865
3 Offshore Wind	3088	2715	2412	2110	1952	1806	1672	1548	1471	1393



Source: Mott MacDonald

Figure 5.4: Projected capital costs under the high renewables scenario using literature learning rates

Technology	2010	2010 Adj.	2015	2020	2025	2030	2035	2040	2045	2050
15 Nuclear PWR	3500	2910	2836	2761	2739	2716	2694	2672	2544	2416
20 ASC Coal PC-CCS	2721	2330	2209	2087	1997	1915	1839	1768	1680	1591
24 CCGT PC-CCS	1026	951	898	845	810	779	751	726	689	653
21 IGCC Precomb CCS	2803	2624	2573	2522	2449	2380	2314	2251	2138	2026
9 Solar PV Crystalline -	2850	2470	1861	1251	904	653	472	341	324	307
2 Onshore Wind (L)	1350	1315	1224	1133	1071	1012	956	904	859	814
3 Offshore Wind	3088	2715	2301	1886	1679	1494	1330	1183	1124	1065

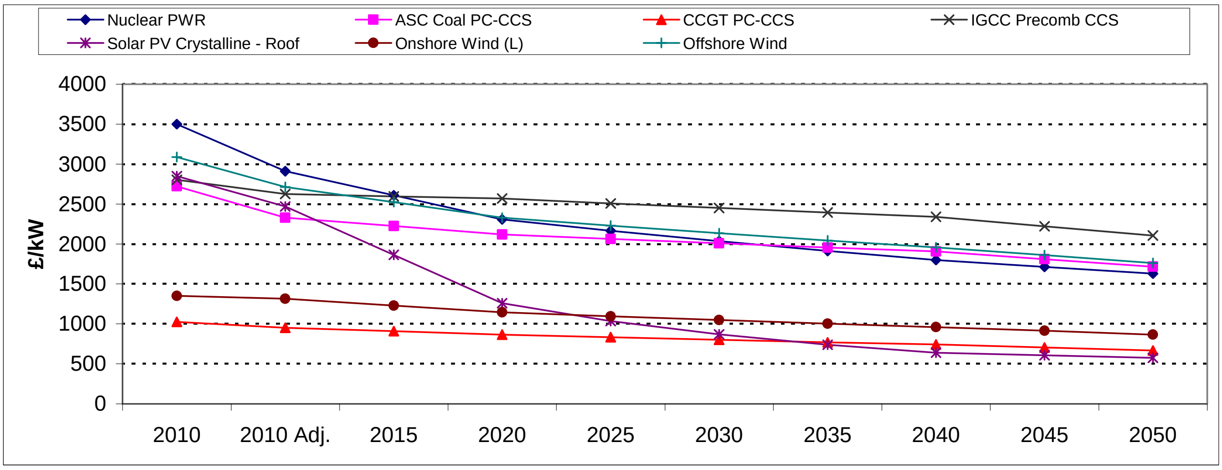


Source: Mott MacDonald

5.2.3 Least cost scenario

Figure 5.5: Projected capital costs under the least cost scenarios using MM estimates

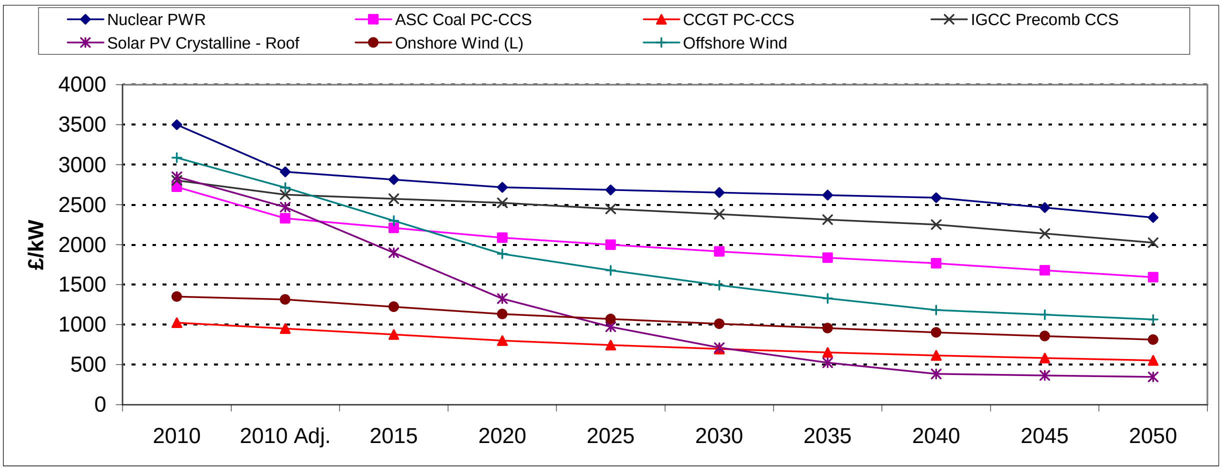
Technology	2010	2010 Adj.	2015	2020	2025	2030	2035	2040	2045	2050
15 Nuclear PWR	3500	2910	2609	2307	2167	2036	1914	1800	1714	1629
20 ASC Coal PC-CCS	2721	2330	2225	2119	2063	2009	1957	1907	1811	1716
24 CCGT PC-CCS	1026	951	909	867	833	800	770	741	704	667
21 IGCC Precomb CCS	2803	2624	2596	2568	2508	2450	2394	2339	2222	2105
9 Solar PV Crystalline -	2850	2470	1864	1258	1035	868	739	639	607	575
2 Onshore Wind (L)	1350	1315	1230	1145	1096	1049	1004	961	913	865
3 Offshore Wind	3088	2715	2523	2331	2231	2136	2045	1959	1861	1763



Source: Mott MacDonald

Figure 5.6: Projected capital costs under the least cost scenario using literature learning rates

Technology	2010	2010 Adj.	2015	2020	2025	2030	2035	2040	2045	2050
15 Nuclear PWR	3500	2910	2814	2718	2684	2652	2620	2588	2464	2340
20 ASC Coal PC-CCS	2721	2330	2209	2087	1997	1915	1839	1768	1680	1591
24 CCGT PC-CCS	1026	951	876	801	746	697	654	616	585	554
21 IGCC Precomb CCS	2803	2624	2573	2522	2449	2380	2314	2251	2138	2026
9 Solar PV Crystalline -	2850	2470	1898	1326	973	714	524	385	366	346
2 Onshore Wind (L)	1350	1315	1224	1133	1071	1012	956	904	859	814
3 Offshore Wind	3088	2715	2301	1886	1679	1494	1330	1183	1124	1065



Source: Mott MacDonald

5.3 Sensitivities

The scenarios above have primarily explored the impact of deployment uncertainties on future technology capex costs. As mentioned, we have not considered the impacts of varying learning rates or initial starting values (which determine the doubling rates). These factors alone mean that there is a significantly larger variation in outcomes using the learning approach. As an illustration, varying the starting value for a technology by +/- 50% (not a big number for an early stage technology) and altering the learning rate by +/- three percentage points would extend the costs reductions from 25% for an original 4 doublings on a 0.93 progress ratio from 13% to 41%. And this is keeping the same eventual deployed capacity level.

Quantifying the impacts of exogenous factors is also fraught with difficulties. Although, contrary to a widely held view, raw material costs are not a key driver here, at least not in direct terms. This is because raw materials generally comprise a small share of input costs. A doubling in raw material costs would probably raise most EPC costs by less than 5%. In practice, the impact may be more than this if suppliers add large risk contingencies for uncertain prices and delivery schedules, which often occur with price spikes.

Technological breakthroughs and strong competition from low cost jurisdictions provide other potential exogenous factors that are more difficult to quantify. At some level, as we have mentioned in the discussion on the learning process, technological advances and supply chain competition are key aspects of learning, however these factors can sometimes lead to large discontinuities in learning trends. In practice, it is difficult to think of examples in the power generation sector which illustrate such discontinuity. Barriers to trade in the real world are substantial and innovative products and services typically come at a premium cost and only slowly provide a downward force on costs.

The capex evolution model developed for this study includes an option to apply a downward step in costs for both technological breakthrough and low cost competition in the period to 2020 and between 2020 and 2040. The step down values have been set at 4-7% each, which if all applied would bring a compound reduction of 15-25%. This is not revolutionary change: it essentially means staying with the same technology. However, as pointed out elsewhere, as we look beyond 2020 there is a real prospect of more fundamental technological changes which would introduce new technologies that may have very different cost structures. These sit mainly in the “unknown unknowns” and “known unknowns” categories.

In the near to medium term, the most significant exogenous factors will undoubtedly remain the state of equipment and service markets and to a lesser extent the currency markets. The large increase in global EPC prices across many generation sectors during 2007-09 was mainly driven by supply chain bottlenecks. These constraints have began to ease in most areas, though as mentioned above, they are still significant for offshore wind and big steam plant (coal and nuclear). While supply chains should response to high prices on the basis that demand would be sustained and market should eventually balance there is clearly a risk in a globally connected EPC market that there will be period shortfall and surplus. These market factors probably account for the biggest uncertainty in the near term for many technologies. Looking forward, these market and exchange rate uncertainties probably mean that prices will move in an asymmetric band around costs which could easily be equivalent to 50% of underlying full costs.

6. Operating costs and cost of capital

6.1 Introduction

This chapter outlines the main assumptions regarding fixed and variable operating costs, fuel and carbon prices and also discount rates that are applied in the levelised cost build-up.

6.2 Fixed operation and maintenance costs

Fixed operation and maintenance (FOM) costs tend to be linked to capital costs of the plant, such that this 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 or mandatory safety inspections, etc. 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.

While staffing costs are typically the largest item, bought in services (marine services for offshore wind), spares and materials can be significant. There is however a degree of arbitrariness in what gets counted in FOM and the variable opex. A certain amount of spares replacement is made on a routine basis, in the same manner as a car servicing agent will replace parts on a time expired basis. This will depend on the nature of the service agreement, owner preferences and any obligations under warranties and safety certification. In the real world the actual spend on operation and maintenance can be lumpy, with many years when there is just a regular cycle of fairly trouble free minor and major servicing costs, but with occasional unforeseen repairs and replacements, when major pressure parts fail, or rotors break. The cost of these incidents is generally spread over the life of the plant.

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 become 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[43]. 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, the fixed operating costs may decline over the life of the plant. For some technologies as the plant moves towards the end of its life costs may increase as the plant becomes more unreliable.

Table 6.1 shows the assumptions used for FOM for the technologies in this report.

[43] Lena Neij, Cost development of future technologies for power generation—A study based on experience curves and complementary bottom-up assessments, Energy Policy, April 2008

Table 6.1: Assumed fixed operations and maintenance costs by technology, expressed as a % of EPC costs

Fixed O&M costs (excluding insurance and grid charges) in 2010/11			
	% of EPC cost		
	Low	Base	High
Onshore Wind	1.0	1.1	1.2
Onshore Wind	0.9	1.0	1.1
Offshore Wind	2.4	2.6	2.8
Wave Fixed	1.9	2.1	2.3
Wave Floating	2.3	2.5	2.7
Tidal Stream	2.0	2.1	2.3
Tidal Barrage	0.8	0.9	1.0
Hydro ROR	0.8	0.9	1.0
Solar PV Crystalline – Roof	0.3	0.4	0.5
Solar PV Crystalline – Ground	0.2	0.3	0.5
Solar PV Thin Film – Roof	0.3	0.4	0.5
Solar PV Thin Film – Ground	0.2	0.3	0.5
Geothermal	1.8	2.0	2.2
Nuclear PWR	1.4	1.5	1.6
Nuclear BWR	1.4	1.5	1.6
ASC Coal Oxy-CCS	2.3	2.5	2.7
ASC Coal PC-CCS	2.3	2.5	2.7
IGCC Precomb CCS	2.3	2.5	2.7
CCGT Precomb CCS	2.3	2.5	2.7
CCGT PC-CCS	2.3	2.5	2.7
Advanced AD Sewage Sludge	2.0	2.1	2.2
Food Waste AD	3.0	3.2	3.5
Manure- Slurry AD	3.0	3.2	3.5
Energy Crops AD	3.0	3.2	3.5
Wood- Grate	3.9	4.2	4.5
Wood – Gasification	2.7	3.0	3.4
MSW-SRF Pyrolysis	2.7	3.0	3.4
Wood – BFBC	4.2	4.4	4.6
Wood – CFBC	3.0	3.2	3.4
Waste Wood – CFBC	3.2	3.4	3.6

Source: Mott MacDonald

6.3 Variable O&M

Variable operations and maintenance (VOM) costs comprise a number of items:

- Incremental servicing costs (rather as the car servicing agent replaces certain parts after a particular mileage is reached, or as its condition fails to meet compliance requirements (like tyre treads). These are the major components for gas and clean fuel fired plant and for some renewable plant that suffers from wear and tear, such as hydropower plant.
- The other big set of items for VOM is the cost of purchasing and disposing of various materials required or generated in the producing electricity. The obvious examples on the input side are solvents, catalysts and reagents used in coal and gas plant for CO_2 capture, while on the output side there are various residues that need to be treated and/or disposed of.
- Water treatment is another variable cost for many types of plant.

These costs are typically expressed on a £/MWh basis. For despatchable plant, these costs will normally be taken into account in determining the owners decision on the plants' despatch and would be netted off its required spark spread[44], like any other truly variable cost. Typically wind and solar plant are seen as having zero variable costs. Table 6.2 shows our assumptions for VOM costs.

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 plant 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 negligible reduction from the current VOM levels.

Table 6.2: Assumed variable operation and maintenance costs in 2010/11

Variable O&M excluding fuel, carbon, decommissioning fund and CO_2 disposal fees in £/MWh			
	Low	Base	High
Onshore Wind - Small	0	0	0
Onshore Wind - Large	0	0	0
Offshore Wind	0	0	0
Wave Fixed	0	0	0
Wave Floating	0	0	0
Tidal Stream	0	0	0
Tidal Barrage	0.2	0.2	0.2
Hydro ROR	0.2	0.2	0.2
Solar PV Crystalline - Roof	0	0	0
Solar PV Crystalline - Ground	0	0	0
Solar PV Thin Film - Roof	0	0	0
Solar PV Thin Film - Ground	0	0	0
Geothermal	5	6	7
Nuclear PWR	1.8	2	2.5

[44] The spark spread is the margin between the price that electricity is sold at and the price of fuel (or feedstock) used to generate the electricity. If carbon costs are also include the spark spread is called a "clean" spark spread.

Variable O&M excluding fuel, carbon, decommissioning fund and CO_2 disposal fees in £/MWh			
Nuclear BWR	1.8	2	2.5
ASC Coal Oxy-CCS	3.2	3.8	4.8
ASC Coal PC-CCS	3.2	3.8	4.8
IGCC Precomb CCS	3.2	3.8	4.8
CCGT Precomb CCS	2.8	3.2	4.1
CCGT PC-CCS	2.8	3.2	4.1
Advanced AD Sewage Sludge	2.3	2.7	3.3
Food Waste AD	2.3	2.7	3.3
Manure- Slurry AD	2.3	2.7	3.3
Energy Crops AD	2.3	2.7	3.3
Wood- Grate	2.7	3	3.4
Wood - Gasification	2.2	2.4	2.6
MSW-SRF Pyrolysis	2.2	2.4	2.6
Wood - BFBC	2.2	2.5	2.7
Wood - CFBC	2.2	2.5	2.7
Waste Wood - CFBC	2.3	2.6	2.8

6.4 Other assumptions

There are a number of other assumptions on plant performance required in order to a calculate the levelised costs of generation including plant lives, plant availability, energy availability (for flow[45] renewables) and conversion efficiencies for technologies using feedstock or fuel. The central starting values are show in Table 6.3. Clearly, a number of these variables will change through time, as technologies improve or available site choices are narrowed.

Table 6.3: Key plant performance assumptions under central case – starting values

	Plant life (years	Plant availability %	Energy availability: %	Efficiency (LHV)%
Onshore Wind (S)	20	98	30	-
Onshore Wind (L)	20	95	30	-
Offshore Wind	20	92	38	-
Wave Fixed	40	90	20	-
Wave Floating	18	86	20	-
Tidal Stream	18	86	35	-
Tidal Barrage	60	98	18	-
Hydro ROR	60	98	45	-
Solar PV Crystalline - Roof	20	98	10	-
Solar PV Crystalline - Ground	20	98	10	-
Solar PV Thin Film - Roof	20	98	10	-
Solar PV Thin Film - Ground	20	97	10	-
Geothermal	35	95	100	-
Nuclear PWR	60	85	100	-

[45] These are wind, wave, tidal, solar and run or river hydropower.

	Plant life (years	Plant availability %	Energy availability: %	Efficiency (LHV)%
Nuclear BWR	60	85	100	-
ASC Coal - Retro Oxy-CCS	40	91	100	44
ASC Coal - Retro PC-CCS	40	91	100	39
ASC Coal Oxy-CCS	40	91	100	44
ASC Coal PC-CCS	40	91	100	39
IGCC Precomb CCS	30	87	100	37
CCGT Precom CCS	30	91	100	49
CCGT Oxy-CCS	30	91	100	49
CCGT PostC CCS	30	91	100	49
Advanced AD Sewage Sludge	25	90	100	59
Food Waste AD	25	92	100	36
Manure- Slurry AD	30	90	100	36
Energy Crops AD	30	90	100	36
Wood- Grate	25	90	100	31
Wood - Gasification	30	90	100	31
MSW-SRF Pyrolysis	30	90	100	31
Wood - BFBC	25	90	100	36
Wood - CFBC	25	90	100	36
Waste Wood - Grate	25	90	100	36

Source: Mott MacDonald

6.4.1 Fuel and carbon

6.4.1.1 Fuel prices

The fuel price assumptions have been taken from DECC's 2010 analysis, which is still the latest UK official assessment available – see Table 6.4. This shows that real coal, gas and oil prices are expected to be higher than the pre-2004 long term average. This reflects the prevailing assumption among governments and international agencies that the world now needs to develop higher cost fossil energy reserves than those accessed in previous decades. We have added a delivery charge of £6/tonne for coal and 2p/therm for gas to give a "burner tip" (or delivered) price. Expressed in £/GJ these scenarios all indicate a substantial cost advantage for coal at the burner tip (as shown in Table 6.5), though of course this is partly offset by the relatively low efficiency of coal fired plant versus gas fired CCGTs. The analysis reported here was based on the "Mid Case" scenario. For the biomass plant fuelled on various wastes we have assumed a zero fuel price (hence a zero "gate fee[46]"). For other biomass plants, we have used DECC's 2010 central biomass projections, which is for a flat £62/tonne on a 18GJ/t CV – equivalent to about 40 p/therm.

Table 6.4: Projected fuel prices

Low Case - Low Global Energy Demand			
2009	Oil - Brent	Gas – NBP	Coal - ARA
Year	$/barrel	p/therm	$/tonne

[46] The gate fee is the price paid or received by the power station at the gate for feedstock. In the case of some wastes power stations may be paid to take the feedstock, in which case the gate fee is positive.

Low Case - Low Global Energy Demand			
2008	102	58	147
2010	50	34	80
2015	58	35	50
2020	60	35	50
2025	60	36	50
2030	60	36	50
Mid Case - Timely Investment, Moderate			
2009 prices	**Oil - Brent**	**Gas – NBP**	**Coal - ARA**
Year	$/barrel	p/therm	$/tonne
2008	102	58	147
2010	70	58	110
2015	75	63	80
2020	80	67	80
2025	85	71	80
2030	90	74	80
High Case – High Demand, Producers' Market Power			
2009 prices	**Oil - Brent**	**Gas – NBP**	**Coal - ARA**
Year	$/barrel	p/therm	$/tonne
2008	102	58	147
2010	84	70	120
2015	102	83	100
2020	120	97	100
2025	120	97	100
2030	120	97	100

Source: DECC - 2010

Table 6.5: Burner tip (delivered) prices for gas and coal

	Average price 2015-2030				Converted in £/GJ net
Scenario	**Gas in p/therm**	**Coal in $/t**	**Gas**	**Coal**	**Coal adv.**
Low	35	50	3.90	1.39	2.50
Mid	68	80	7.37	2.14	5.23
High	95	100	10.21	2.64	7.57

Source: Mott MacDonald estimates based on DECC assumptions

6.4.1.2 Carbon prices

The base case carbon price assumptions has been taken from DECC’s central projection, in which prices rises slowly from £14.10 a tonne CO_2 in 2010 to £16.3/t in 2020, then more rapidly to £70/t in 2030 and £135/t in 2040. Averaged over the period to 2040 this works out at £54.3/t, while discounted at 10% the average is about £25/t. Carbon prices are applied to all fossil fuel fired plant (even those fitted with CCS) on he basis of their emission factor and are so included in the levelised cost of electricity (LCOE).

6.4.2 Discount rates for technologies

In this analysis levelised costs are 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 using a standard Capital Asset Pricing Model to generate a set of Weighted Average Cost of Capital (WACC). Estimates of WACC have been made for the three archetypal scenarios based on the level of deployment and support for the technologies. The estimated range of WACCs for the three scenarios are shown in Table 6.6 while Table 6.7 shows the central case discount rates (which are taken from the average of the range for the Balanced Efforts scenario).

Table 6.6: Estimates WACC by technology under the three archetypal scenarios – Pre-tax real

Balanced effort scenario	Current		2020		2040	
	Low	**High**	**Low**	**High**	**Low**	**High**
Nuclear	9%	13%	8%	11%	6%	9%
Offshore wind	10%	14%	9%	12%	7%	10%
CCGT	6%	9%	6%	9%	5%	8%
Onshore wind	7%	10%	6%	8%	5%	8%
CCS, coal	12%	17%	11%	15%	8%	12%
CCS, gas	12%	17%	11%	15%	8%	12%
Biomass	9%	13%	8%	11%	6%	8%
Hydro ROR	6%	9%	6%	9%	5%	8%
Wave (fixed)	10%	14%	9%	12%	6%	9%
Wave (floating)	13%	18%	12%	16%	9%	14%
Tidal stream	12%	17%	11%	15%	9%	13%
Tidal barrage	12%	17%	11%	15%	8%	12%
Solar PV	6%	9%	6%	9%	5%	8%
Dedicated biogas (AD)	7%	10%	7%	10%	6%	9%
High renewables scenario	**Current**		**2020**		**2040**	
	Low	**High**	**Low**	**High**	**Low**	**High**
Nuclear	9%	13%	9%	13%	8%	12%
Offshore wind	10%	14%	7%	10%	6%	8%
CCGT	6%	9%	6%	9%	5%	8%
Onshore wind	7%	10%	6%	8%	5%	8%
CCS, coal	12%	17%	12%	17%	11%	16%
CCS, gas	12%	17%	11%	15%	10%	15%
Biomass	9%	13%	6%	9%	6%	8%
Hydro ROR	6%	9%	6%	9%	5%	8%
Wave (fixed)	10%	14%	7%	10%	6%	9%
Wave (floating)	13%	18%	10%	14%	8%	12%
Tidal stream	12%	17%	9%	14%	7%	11%
Tidal barrage	12%	17%	9%	13%	7%	10%
Solar PV	6%	9%	6%	9%	5%	8%
Dedicated biogas (AD)	7%	10%	7%	10%	6%	9%
Least cost compliance scenario	**Current**		**2020**		**2040**	
	Low	**High**	**Low**	**High**	**Low**	**High**
Nuclear	9%	13%	8%	11%	6%	9%

Balanced effort scenario	Current		2020		2040	
Offshore wind	10%	14%	10%	14%	9%	13%
CCGT	6%	9%	6%	9%	5%	8%
Onshore wind	7%	10%	6%	8%	5%	8%
CCS, coal	12%	17%	12%	17%	11%	16%
CCS, gas	12%	17%	11%	15%	8%	12%
Biomass	9%	13%	8%	11%	6%	8%
Hydro ROR	6%	9%	6%	9%	5%	8%
Wave (fixed)	10%	14%	10%	14%	9%	13%
Wave (floating)	13%	18%	13%	18%	12%	17%
Tidal stream	12%	17%	12%	17%	11%	16%
Tidal barrage	12%	17%	12%	17%	11%	16%
Solar PV	6%	9%	6%	9%	5%	8%
Dedicated biogas (AD)	7%	10%	7%	10%	6%	9%

Source: Oxera Consulting

Table 6.7: Central case discount rate assumptions

Discount rate (pre-tax, real)	Current	2020	2040
Nuclear (new build)	11.0%	9.5%	7.5%
Offshore wind	12.0%	10.5%	8.3%
CCGT	7.5%	7.5%	6.9%
Onshore wind	8.5%	7.0%	6.4%
CCS, coal	14.5%	12.9%	10.2%
CCS, gas	14.5%	12.9%	10.2%
Biomass	11.0%	9.3%	7.1%
Hydro ROR	7.5%	7.5%	6.9%
Wave (fixed)	12.0%	10.1%	7.7%
Wave (floating)	15.5%	13.9%	11.6%
Tidal stream	14.5%	12.9%	10.7%
Tidal barrage	14.5%	12.9%	10.2%
Solar PV	7.5%	7.5%	6.9%
Dedicated biogas (AD)	8.5%	8.5%	7.9%

Source: Oxera Consulting

7. Main findings on levelised costs

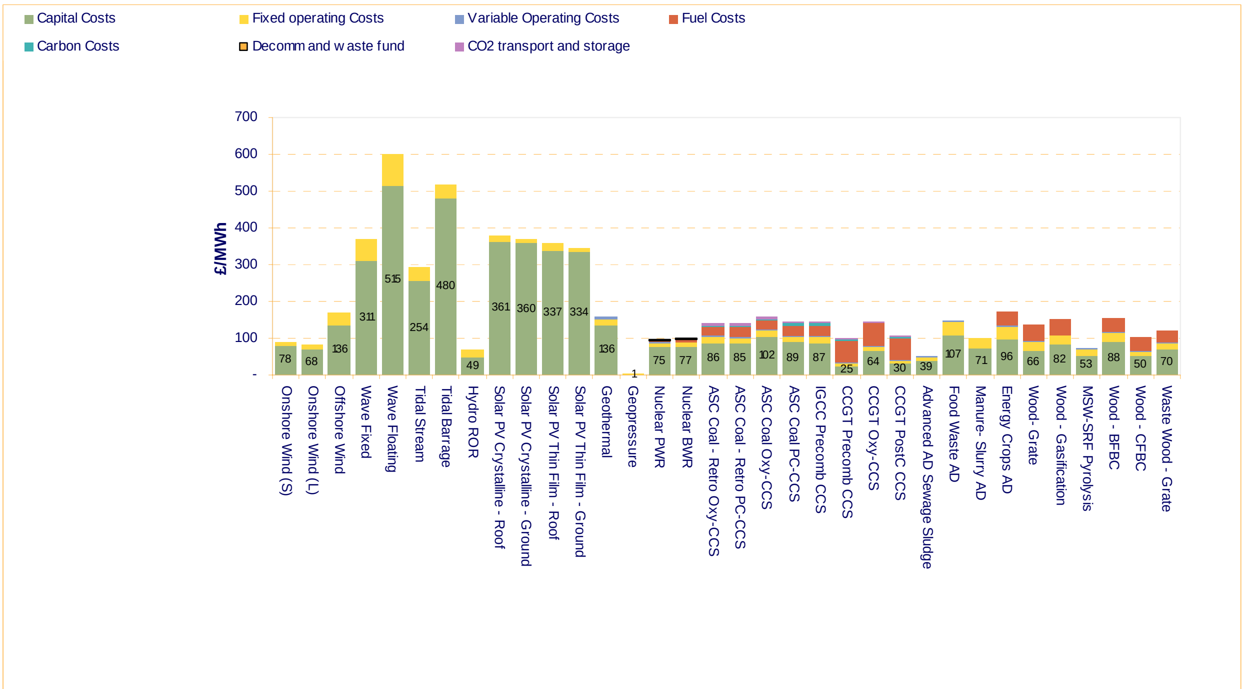
7.1 Introduction

This chapter summarises the main findings with regards to the levelised costs of electricity. These levelised costs have been generated[47] using the capital cost projections reported in chapter 5 and the other inputs assumptions regarding non-fuel opex, fuel and carbon prices, plant performance parameters and discount rates summarised in Chapter 6. We first consider the current levelised costs and then consider projected costs.

7.2 Build-up of current levelised costs

Figure 7.1 shows the build-up of current levelised costs for all the technologies under base case assumptions regarding capital and non-fuel operating costs, fuel and carbon prices and plant performance parameters, and central discount rate assumptions. Figure 7.2 shows the total levelised costs. Both figures assume all projects start in 2011, but that capital costs are frozen at current levels (so therefore include any market congestion premiums (or discounts) that exist today. Differentiated discount rates are applied, using the central case from the Oxera analysis – see Table 6.7. The impact of varying discount rates is discussed later.

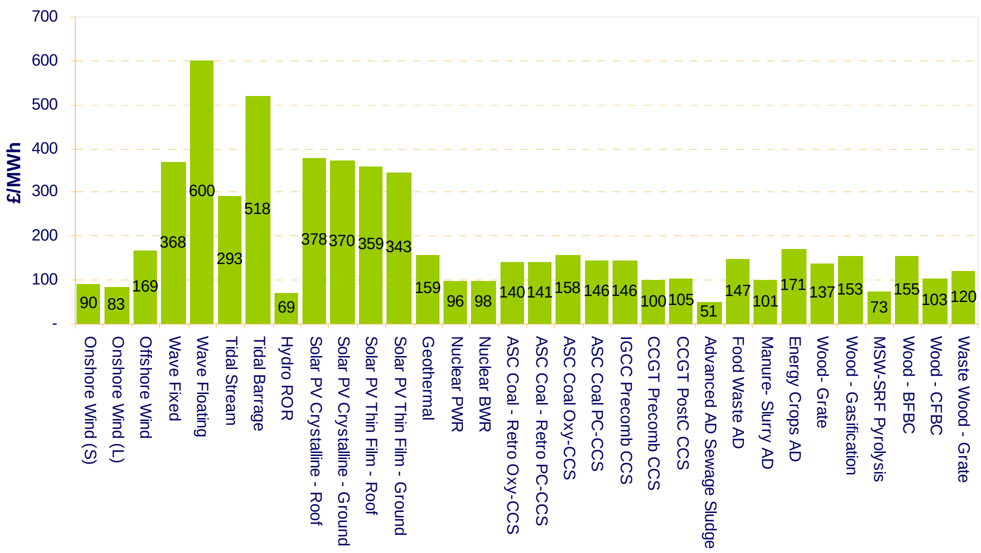
Figure 7.1: Build-up of levelised costs in 2011, under base case assumptions and average discount rate



Source: Mott MacDonald

[47] The LCOE have been calculated using an updated version of DECC's LCOE model.

Figure 7.2: Levelised costs by technology in 2011 under base case assumptions and average discount rates



Source: Mott MacDonald

The two main features to note from these charts are as follows:

1 There is a very large variation in costs between technologies, with almost an order of magnitude difference between least cost and most expensive options. This range largely reflects underlying costs, however it is accentuated by the differentials in discount rates between perceived low and high risk technologies.
2 Allowing for the application of differentiated discount rates, the costs estimated here are consistent with those estimated in MML's UK Generation Cost Update report for DECC of June 2010.

We now consider the findings by technology group.

Run-or-river hydro, a long established renewable generation technology, is estimated to have one of the lowest levelised costs at £69/MWh. This reflects its established design and its comparatively low risk, assuming planning and local community stakeholders endorse the scheme.

Onshore wind costs are estimated to be £83-£90/MWh, based on typical sites available today. Lower costs would have been achievable on the better sites already developed. The range here reflects WTG size rather than wind resource. Offshore wind is much more expensive - estimated at £169/MWh for an early R3 scheme, which is about double the onshore costs. A significant amount of this premium is due to the higher discount rate applied, which in turn reflects lenders/developers' risk premium. There are lower cost offshore developments underway but these projects started development at least two years ago.

Of the low carbon technologies now being considered for wide deployment, solar PV is quite clearly the most expensive at £320-360/MWh. This reflects the early stage of this technology and the low annual capacity factors (~10%) achievable in a UK setting. The rationale for its widespread support is that this technology is clearly on a steep downward cost trajectory.

There is a big variation in the costs of AD applications. Advanced AD sewage is easily the least cost at about £50/MWh. This reflects minimal additional feedstock treatment (beyond that built into the sewage treatment works). Other AD options require significant feedstock treatment/ complicated handling and so their costs range between £100/MWh (manure/slurry) and £170/MWh (energy crops). In all cases gate fees for waste feedstocks are assumed to be zero, however, AD systems fed on energy crops include the biomass purchase cost.

The larger wood fired biomass schemes offer costs at around £100/MWh and £125/MWh for the 150MW and 40MW electricity-only FBC plants. 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.

It should be noted that for most of the biomass technologies mentioned here, there can be very considerable levelised cost reductions if they can be configured as combined heat and power schemes, although this does obviously require a captive heat load.

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 is expected to provide an annual capacity factor of 35-40%, versus around 20% for a floating wave device: although we have noted that this availability advantage for tidal stream versus wave has yet to be confirmed. 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. Fixed wave, which has lower capital costs than floating, is estimated to cost £368/MWh.

Nuclear appears as a comparatively low cost option, at £89/MWh, however, this estimate must be considered highly uncertain given the limited and troublesome track record of the two reactor models currently being considered for the UK and the lack of recent experience in the UK (among contractors and regulators).

CCS is seen as being a medium price option, with gas options, estimated to cost around £105/MWh, and coal-CCS at about £150/MWh, indicating an advantage to gas of about £45/MWh. Much of this differential reflects the currently elevated prices of coal equipment versus CCGTs, and the higher carbon intensity of coal generation versus gas. However, both these estimates must be considered highly uncertain, given no utility scale demonstration has yet been commissioned.

Cost structures:

Looking at the cost structures, it is clear that for most renewable technologies, with the exception of woody biomass fired technologies, capital costs is by far the largest element. Fixed operations and maintenance costs vary considerably between low levels for solar, onshore wind, hydro and AD sewage and the high levels for offshore wind, wave and tidal stream, and most biomass options. Fuel becomes a significant element only for the woody biomass options and AD systems using energy crops as primary feedstock.

Of the other low carbon technologies, nuclear costs are largely fixed, and dominated by capital costs, while coal-CCS's levelised costs are two-thirds fixed; one third fuel, and gas-CCS is two-thirds fuel and one third fixed. The implication of this is that gas-CCS would see a proportionately smaller increase in costs versus coal-CCS as the annual capacity factor is reduced.

7.2.1 Uncertainties

The levelised costs above are based on a central projection of capital costs and plant performance parameters. As mentioned in the chapter on capital costs, there is some considerable uncertainty about the costs even for a given design spec and site conditions, which in most cases reflects the lack of transactions. The two notable exceptions are wind (both on and offshore) and solar PV where there has been a continuing stream of business. This uncertainty can be called a “liquidity uncertainty”.

There is also the issue of changes in costs that would arise from different design specs, scale, location, and plant performance parameters such as efficiencies, CO_2 removal rates, annual capacity factors, plant life, etc. This group of uncertainties can be considered the “basis uncertainty”.

Table 7.1 provides our subjective 95% confidence limits on the MML initial capex estimates, which can be seen as a combination of the above liquidity uncertainty and basis uncertainty. It generally shows a fairly symmetrical pattern of uncertainty, though not exactly. Most notably it shows the much greater bands of uncertainty for early stage technologies.

Table 7.1: Subjective 95% confidence limits on MML initial capex estimates

	% below	% above		% below	% above
Onshore Wind (S)	5	5	ASC Coal PC-CCS	20	30
Onshore Wind (L)	5	5	IGCC Precomb CCS	20	25
Offshore Wind	10	10	CCGT Precomb CCS	20	25
Wave Fixed	20	20	CCGT PC-CCS	20	25
Wave Floating	20	20	Advanced AD Sewage Sludge	10	10
Tidal Stream	20	20	Food Waste AD	10	10
Tidal Barrage	25	20	Manure- Slurry AD	10	10
Hydro ROR	5	5	Energy Crops AD	10	10
Solar PV Crystalline - Roof	10	5	Wood- Grate	10	10
Solar PV Crystalline - Ground	10	5	Wood - Gasification	20	25
Solar PV Thin Film - Roof	10	5	MSW-SRF Pyrolysis	15	20
Solar PV Thin Film - Ground	10	5	Wood - BFBC	10	10
Geothermal	15	15	Wood - CFBC	10	10
Nuclear PWR	15	20	Waste Wood - Grate	10	10
ASC Coal Oxy-CCS	20	25			

Source: Mott MacDonald

Commodity price uncertainty, particularly relating to fuel and feedstock prices, and also carbon prices provide a third area of uncertainty. While these commodity prices can be hedged in real projects, in an economic analysis these are a major contributor to uncertainty for certain categories of low carbon technologies, most notably the CCS options.

As mentioned earlier, the choice of discount rates applied, which depends on perceived risks for each technology category provides a further major uncertainty. The difference between Oxera’s high and low estimates of discount rate for offshore wind and nuclear would move levelised costs by about £40/MWh and £20/MWh respectively.

Table 7.2 provides a summary of the uncertainties that have been considered in this analysis and those that have been excluded. This shows that we have considered only those uncertainties relating to learning effects that affect capital costs (and also fixed operations and maintenance costs) and discount rates (which are affected by risk perceptions (and also deployment/learning).

Table 7.2: Uncertainties included and excluded in this analysis

Cost driver/assumption	Range available and considered [emboldened]		
Initial capex (liquidity/basis uncertainties)	Low	**Central**	High
Learning curve approach:			
- Learning rates (Progress ratios)	Low	**Central**	High
- Projected cumulative employment	**Low**	**Central**	**High**
MML learning assessment	**Low**	**Central**	**High**
Discount rates	**Low deployment - range/average**	**Central deployment - range/average**	**High deployment - range/average**
Fuel /feedstock and carbon prices	[Low	**Central**	High]
Plant performance assumptions	[Low	**Central**	High]
Plant - other cost assumptions	[Low	**Central**	High]
Technological breakthroughs	[**Excluded** / Included]		
Low cost suppliers breakthroughs	[**Excluded** / Included]		
Emboldened values means uncertainty has been included.			
Note: Archetypal scenarios combine combinations of different assumptions of technology deployment/learning with matched discount rates (either average or range)			

Source: Mott MacDonald

7.3 Projected levelised costs under archetypal scenarios

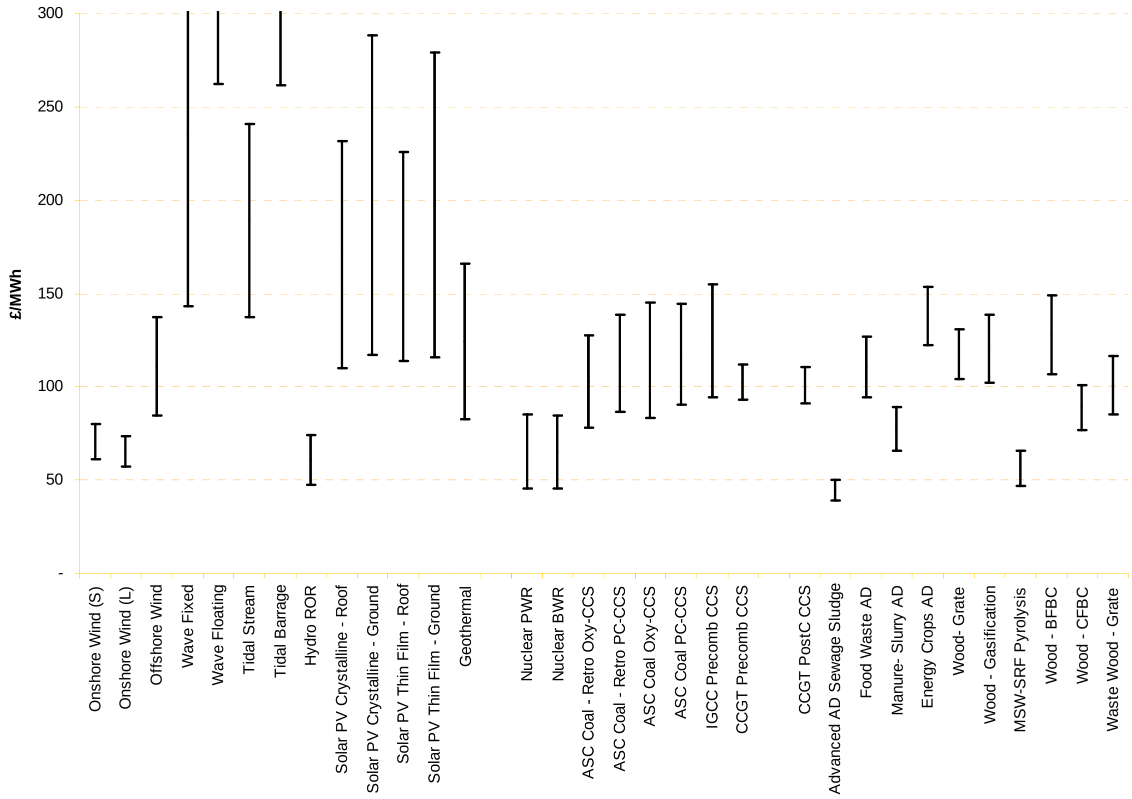
Overall, the picture is one of falling real levelised costs for low carbon technologies. The relative movements of different technologies are largely driven by differential learning rates under the different deployment/business environment projections. This implies that the selection of scenario can play a significant role in a technology's relative position. The two approaches applied to handling learning, generally provide a similar ordering however there are some differences.

Figure 7.3 and Figure 7.4 summarises the results showing the range of costs under the three scenarios, using the full discount rate range from the Oxera analysis under the MML assessment approach for 2020 and 2040 respectively. Figure 7.5 and Figure 7.6 show the same levelised costs when the literature learning rates are applied. Figure 7.7 shows the range if we adopt the high to low case for all technologies and combining the results of the two assessment processes. As mentioned earlier these ranges still exclude impacts of starting price uncertainty, basis uncertainty and fuel and carbon price uncertainty.

With this caution in mind, our comments below outline the main themes by technology group, using the ranges generated using the technical assessments. We then comment on where there are notable differences between the technical assessment and the results of applying the learning curve approach.

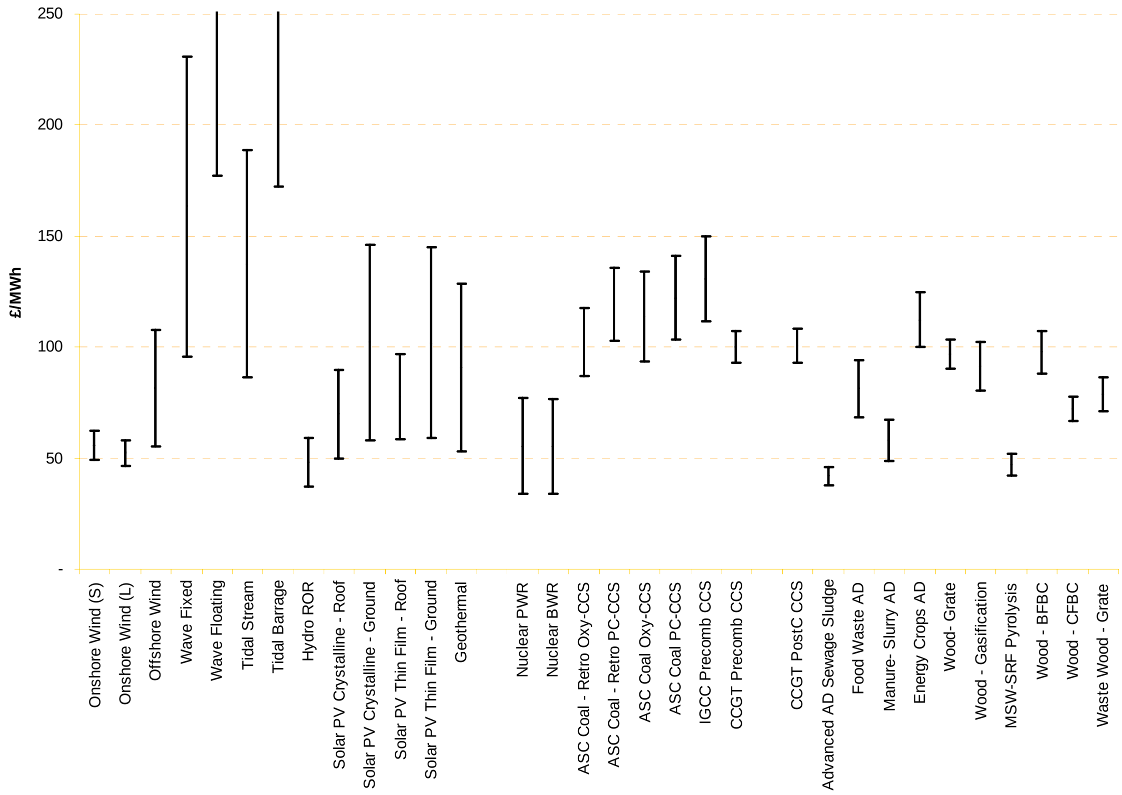
Mini hydro and onshore wind are projected to remain low cost in all the scenarios, with costs in 2040 of about £44-50/MWh and £51-60/MWh, respectively. Unlike for offshore wind, there is little prospect of scale benefits, and moderate scope for technology improvement, other than through rationalisation of production techniques and supply chain upgrades.

Figure 7.3: Levelised costs in 2020 under base case using MML learning assessment (and applying full discount rate uncertainty)



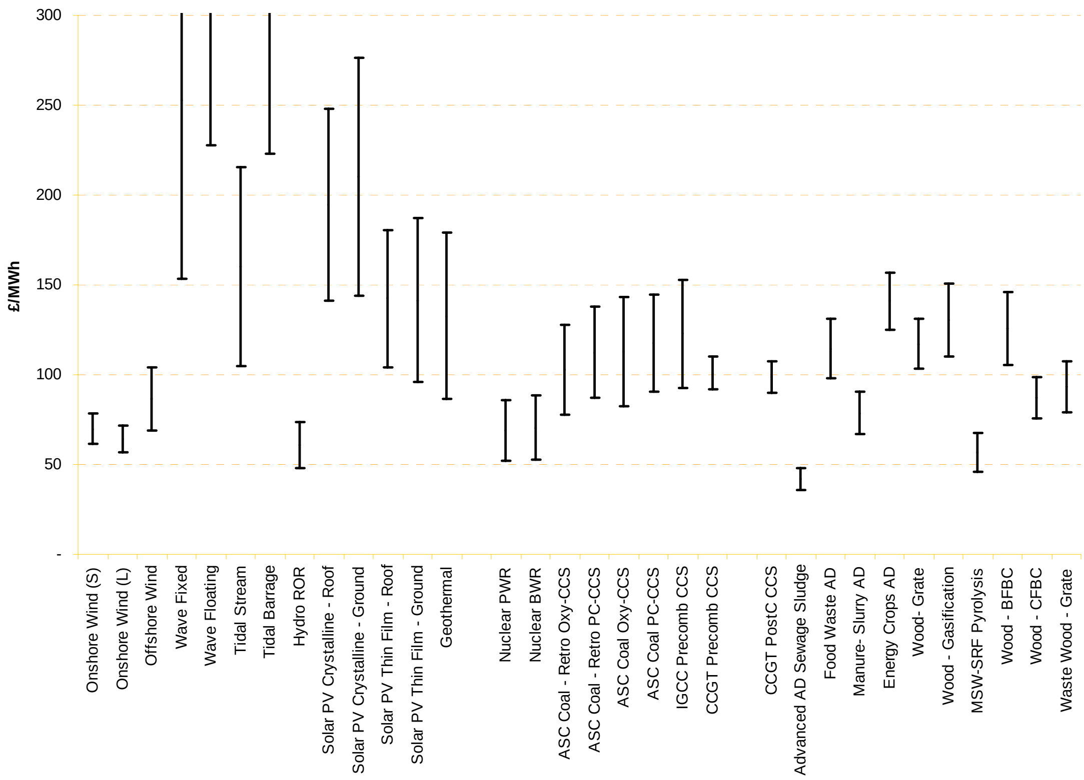
Source: Mott MacDonald

Figure 7.4: Levelised costs in 2040 under base case using MML learning assessment (and applying full discount rate uncertainty)



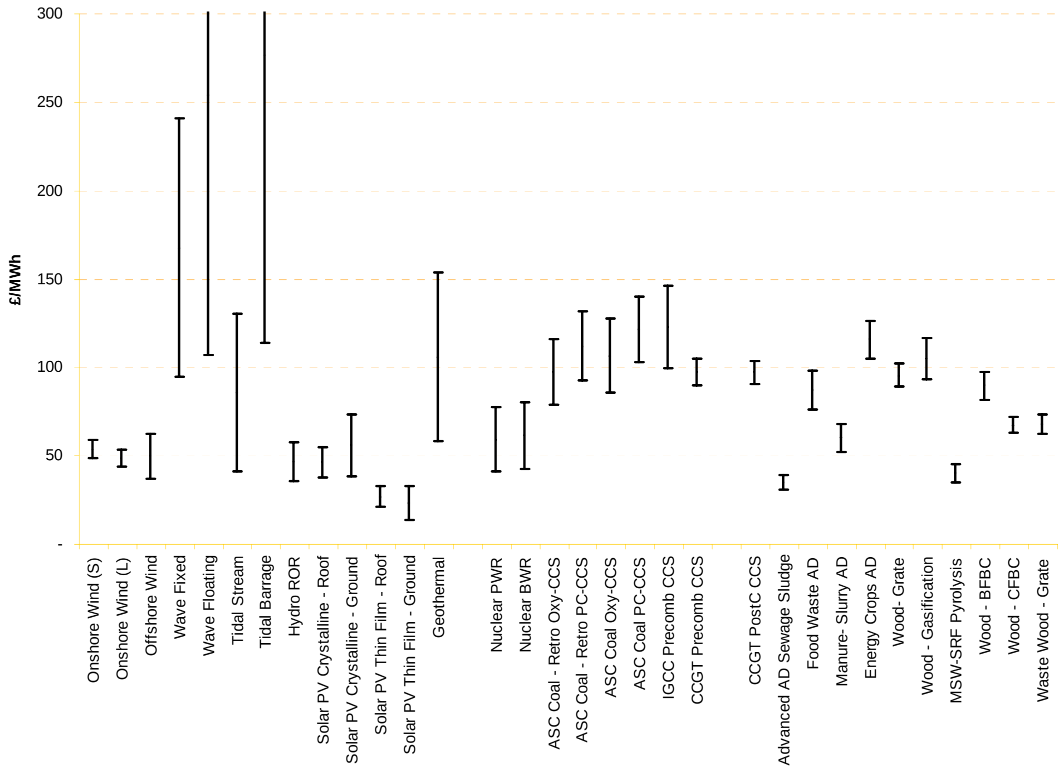
Source: Mott MacDonald

Figure 7.5: Levelised costs in 2020 under base case using literature learning rates (and applying full discount rate uncertainty)



Source: Mott MacDonald

Figure 7.6: Levelised costs in 2040 under base case using literature learning rates (and applying full discount rate uncertainty)



Source: Mott MacDonald

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 larger windfarms 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 either new material technologies will allow the larger structures to be built (assuming the industry sticks with horizontal axis) or else 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 £92-122/MWh and £60-96/MWh in 2020 and 2040, respectively.

Solar PV sees huge reduction in costs but only gets close to offshore wind and nuclear by 2040, reaching £55-74/MWh for the lowest cost applications. 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 relative position of the different PV applications, between roof and ground and crystalline and thin film varies depending on the relative learning rates of different components (modules versus installation/balance of plant for example), such that under some scenarios roof mounted application becomes cheaper than ground mounted ones.

The levelised costs for nuclear are projected to fall from the around £89/MWh to £39-65/MWh under the MML assessment approach. The low end of this cost looks bullish, however it is worth pointing out that a couple of OECD jurisdictions (South Korea and Sweden) are already achieving close to this. Of course, this would require that the UK's whole regulatory, planning, licensing and industrial relations environment was as benign as any elsewhere.

All the CCS options see little decrease in levelised costs, largely as carbon price increases offset capex and performance improvements. Gas-CCS costs stay at £95-104/MWh, while coal-CCS sees some reduction as global coal EPC markets rebalance, with prices falling to about £110-128/MWh. This means coal-CCS has a premium versus gas-CCS of about £15-24/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 25ppt (taking a £20/MWh differential) 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.

Most of the CCS costs would appear significantly lower if a much lower carbon price was assumed. Assuming a flat £20/t CO_2 price, the costs are brought down by about £10/MWh.

We are not expecting any dramatic developments in any of the listed bioenergy 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 bioethanol/biodiesel (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 biomethane or biofuels.

In the near to medium term we are projecting relatively moderate reductions in the costs of the main prime movers for biomass generation (AD, gas engines, combustors and boilers, small/medium sized 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.

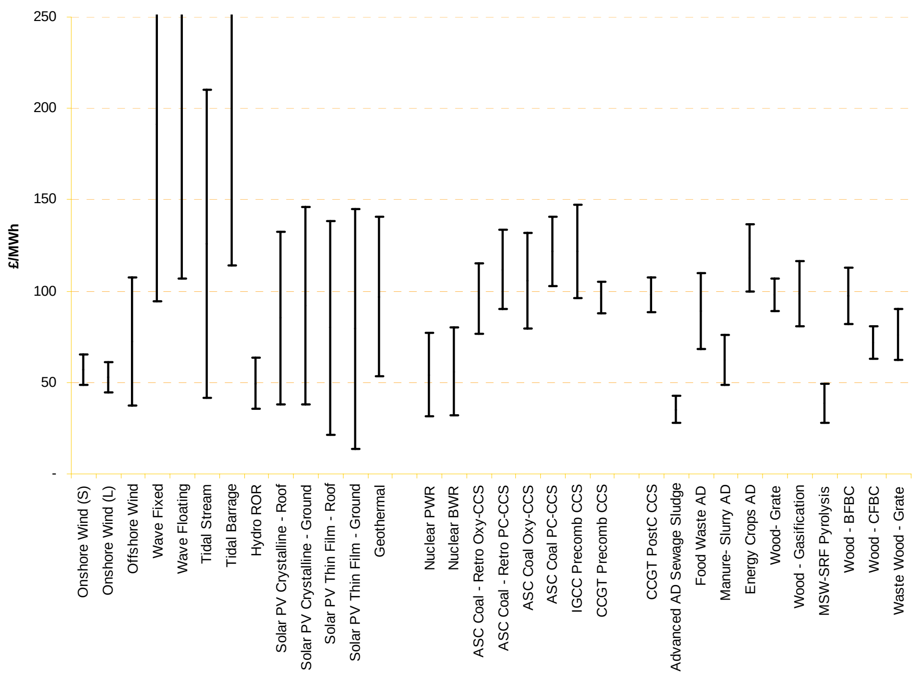
Wave and tidal stream technologies are projected to see among the deepest reductions, especially under favourable deployment scenarios, however none of them is projected to rival offshore wind in terms of levelised costs. Tidal stream is expected to continue to have an advantage versus floating wind given its expected higher annual capacity factor. We are projecting a levelised cost for tidal stream of £97-162/MWh, versus £219-398/MWh for floating wave. Fixed wave, with its lower capex, could see costs of £115-£195/MWh.

As mentioned above, the projected levelised costs from applying the learning rates seen in the literature (and our deployment assumptions as embodied within the archetypal scenarios) is similar to that using MML assessment. The main differences are that the literature rates generally provide a more optimistic picture of cost reductions, especially for wind, solar PV and the marine renewables. One exception is nuclear, where the learning curve approach yields higher costs than the techno-economic assessments. As mentioned before, this is due to the historically poor rate of cost reduction in nuclear sector. Even so, this approach still sees a significant decline in levelised costs, although this is more a reflection of the decline in the discount rates for nuclear, the central point which falls 3.5% between 2011 and 2040 (and would alone account for a £15-18/MWh reduction.

7.4 Sensitivities

Technologies have more favourable cost evolution under scenarios where they are supported and 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 over £30/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.

Figure 7.7: Levelised costs under the full range of learning (MML and literature rates) and discount rate variations under base case assumptions on plant performance, fuel and carbon prices



Source: Mott MacDonald

7.5 Conclusions on future levelised costs

The above analysis indicates that there is considerable scope for levelised costs of renewables and nuclear technologies to come down, with perhaps less scope for CCS costs. The size of cost reductions is likely to be very dependent of the extent to which the global and national business and policy frameworks are supportive of the technologies. With regard to ranking technologies it is possible to categorise some technologies as being definitely low cost (onshore wind, mini hydro, advanced AD sewage, pryrolysis of MSW/SRF) and others as high cost (tidal barrage, tidal stream, and wave) even allowing for future learning.

CCS is likely to fall somewhere in the middle range, with little prospect of becoming a low cost option. This reflects the complexity of the technology (a parasitic chemical plant integrated with a conventional fossil fuel power plant) and the fact that a significant part of its levelised costs will be accounted for by fuel costs and some residual carbon price exposure. While, the gas-CCS options appear to have a significant advantage this really rests upon one's long term view of relative gas and coal prices. Under all DECC's latest published fuel price projections, the gas option always undercuts coal-CCS.

For most other technologies there is considerable uncertainty, particularly for nuclear, offshore wind and solar PV. Everyone expects solar PV costs to fall substantially, however it is unclear whether/when solar will match the lower cost options. Once one takes account of the avoided network costs and losses, our view is that solar PV will become a low cost solution in the UK sometime between 2020 and 2040. The nuclear outlook is much less clear and our view is that the UK will only see deep reductions in levelised costs if the policy, regulatory and licensing regime is supportive and the industry can develop both effective production logistics and efficient supply chain management. Here the UK will need to rely quite heavily on learning outside of the UK. For offshore wind, the UK is potentially a pivotal player, so has more scope for pushing this technology forward on an independent basis.

Appendices

Appendix A. Deployment scenarios

Projected capacities used in learning curve analysis.

	Installed capacity: MW			Capacity in 2020: MW		Capacity in 2040: MW	
	UK	Global		UK	Global	UK	Global
Onshore Wind (S)	400	19700	Low	1267	39100	1700	76755
			Base	1490	46000	2000	90300
			High	1714	52900	2300	103845
Onshore Wind (L)	3600	177300	Low	11399	351900	15300	690795
			Base	13410	414000	18000	812700
			High	15422	476100	20700	934605
Offshore Wind	1400	3160	Low	11050	63750	17000	255000
			Base	13000	75000	20000	300000
			High	14950	86250	23000	345000
Wave Fixed	100	200	Low	120	250	200	1500
			Base	200	500	400	3000
			High	250	1000	900	8000
Wave Floating	100	200	Low	120	250	160	1000
			Base	200	500	300	3000
			High	400	1250	1000	10000
Tidal Stream	100	200	Low	200	500	500	3000
			Base	300	1000	1500	5000
			High	500	3000	3000	15000
Tidal Barrage	100	300	Low	200	500	1000	3000
			Base	300	1000	5000	8000
			High	500	3000	9000	20000
Hydro ROR	100	2000	Low	150	3000	200	5000
			Base	300	5000	500	9000
			High	400	8000	800	15000
Solar PV Crystalline - Roof	100	16000	Low	723	37400	3783	187850
			Base	850	44000	4450	221000
			High	978	50600	5118	254150
Solar PV Crystalline - Ground	100	16000	Low	723	37400	3783	150000
			Base	850	44000	4450	221000
			High	978	50600	5118	300000
Solar PV Thin Film - Roof	100	2000	Low	425	9350	3400	35000
			Base	500	11000	4000	50000
			High	575	12650	4600	100000
Solar PV Thin Film - Ground	100	2000	Low	425	9350	3400	35000
			Base	500	11000	4000	50000
			High	575	12650	4600	100000
Geothermal	100	12000	Low	85	17850	850	43350
			Base	100	21000	1000	51000
			High	115	24150	1150	58650
Nuclear PWR	10900	325000	Low	13600	346800	25500	487900

	Installed capacity: MW			Capacity in 2020: MW		Capacity in 2040: MW	
			Base	16000	408000	30000	574000
			High	18400	469200	34500	660100
Nuclear BWR	1000	75000	Low	1000	80006	1000	112550
			Base	2000	94125	5000	132412
			High	3000	108244	10000	152274
ASC Coal - Retro Oxy-CCS	100	1000	Low	300	3000	600	10000
			Base	600	5000	3000	30000
			High	1000	9000	6000	100000
ASC Coal - Retro PC-CCS	100	1000	Low	300	3000	600	10000
			Base	600	5000	3000	30000
			High	1000	9000	6000	100000
ASC Coal Oxy-CCS	100	1000	Low	300	3000	600	10000
			Base	600	5000	3000	30000
			High	1000	9000	6000	100000
ASC Coal PC-CCS	100	1000	Low	300	3000	600	10000
			Base	600	5000	3000	30000
			High	1000	9000	6000	100000
IGCC Precomb CCS	100	1000	Low	300	3000	600	10000
			Base	600	5000	3000	30000
			High	1000	9000	6000	100000
CCGT Precomb CCS	100	1000	Low	300	3000	600	10000
			Base	600	5000	3000	30000
			High	1000	9000	6000	100000
CCGT PC-CCS	100	500	Low	300	3000	600	10000
			Base	600	5000	3000	30000
			High	1000	9000	6000	100000
Advanced AD Sewage Sludge	100	200	Low	120	300	500	1000
			Base	300	600	750	2000
			High	500	1000	1000	3000
Food Waste AD	100	200	Low	120	300	500	1000
			Base	300	600	750	2000
			High	500	1000	1000	3000
Manure- Slurry AD	100	200	Low	120	300	500	1000
			Base	300	600	750	2000
			High	500	1000	1000	3000
Energy Crops AD	100	200	Low	120	300	500	1000
			Base	300	600	750	2000
			High	500	1000	1000	3000
Wood- Grate	100	500	Low	120	650	160	1300
			Base	200	1000	280	2500
			High	250	2000	350	5000
Wood - Gasification	100	500	Low	120	650	160	1300
			Base	200	1000	280	2500

	Installed capacity: MW			Capacity in 2020: MW		Capacity in 2040: MW	
			High	250	2000	350	5000
MSW-SRF Pyrolysis	100	500	Low	120	650	160	1300
			Base	200	1000	280	2500
			High	250	2000	350	5000
Wood - BFBC	150	750	Low	300	1000	500	3000
			Base	1000	4000	3000	12000
			High	2000	7500	6000	20000
Wood - CFBC	150	750	Low	300	1000	500	3000
			Base	1000	4000	3000	12000
			High	2000	7500	6000	20000
Waste Wood - CFBC	150	750	Low	300	1000	500	3000
			Base	1000	4000	3000	12000
			High	2000	7500	6000	20000

Appendix B. Capex projections for low carbon generation

Installed capital costs in £/kW

Balanced efforts scenario	2011	2011 adjusted	2015	2020	2025	2030	2035	2040
Onshore Wind (S)	1450	1413	1344	1274	1232	1192	1153	1116
Onshore Wind (L)	1350	1315	1249	1182	1143	1105	1069	1034
Offshore Wind	3088	2715	2472	2229	2102	1982	1870	1764
Wave Fixed	3270	3149	2848	2548	2364	2195	2039	1896
Wave Floating	4040	3892	3378	2863	2552	2278	2037	1825
Tidal Stream	3600	3102	2852	2602	2466	2340	2222	2111
Tidal Barrage	3300	3300	3238	3177	3115	3055	2996	2939
Hydro ROR	2250	2185	2128	2070	2026	1983	1941	1899
Solar PV Crystalline - Roof	2850	2470	1845	1219	991	828	710	623
Solar PV Crystalline - Ground	2800	2443	1861	1278	1067	914	802	719
Solar PV Thin Film - Roof	2650	2318	1729	1140	938	795	694	619
Solar PV Thin Film - Ground	2600	2291	1749	1207	1012	875	776	704
Geothermal	4725	4655	4389	4123	3841	3591	3371	3177
Nuclear PWR	3200	2650	2503	2356	2268	2184	2103	2026
Nuclear BWR	3000	2604	2420	2235	2153	2074	1999	1926
ASC Coal - Retro Oxy-CCS	2726	2364	2116	1868	1721	1590	1472	1365
ASC Coal - Retro PC-CCS	2770	2376	2125	1875	1749	1634	1527	1428
ASC Coal Oxy-CCS	2761	2398	2210	2023	1912	1810	1716	1628
ASC Coal PC-CCS	2721	2330	2157	1984	1890	1802	1719	1641
IGCC Precomb CCS	2803	2624	2488	2351	2176	2016	1868	1733
CCGT Precomb CCS	881	831	807	783	746	712	680	650
CCGT PC-CCS	1026	951	909	867	833	800	770	741
Advanced AD Sewage Sludge	2605	2438	2269	2101	2010	1925	1844	1767
Food Waste AD	7278	6803	6312	5821	5493	5188	4903	4638
Manure- Slurry AD	5094	4760	4450	4139	3919	3713	3519	3338
Energy Crops AD	6818	6373	5921	5468	5184	4918	4668	4435
Wood- Grate	3350	3129	2995	2860	2766	2675	2588	2504
Wood - Gasification	4300	4010	3645	3281	3037	2814	2612	2429
MSW-SRF Pyrolysis	3119	2908	2655	2401	2246	2104	1973	1852
Wood - BFBC	3828	3828	3547	3266	3132	3005	2885	2771
Wood - CFBC	2178	2178	2022	1866	1796	1730	1668	1608
Waste Wood - CFBC	3190	2987	2877	2766	2675	2588	2505	2426

Renewable scenario	2011	2011 adjusted	2015	2020	2025	2030	2035	2040
Onshore Wind (S)	1450	1413	1324	1235	1182	1132	1084	1039
Onshore Wind (L)	1350	1315	1230	1145	1096	1049	1004	961
Offshore Wind	3088	2715	2412	2110	1952	1806	1672	1548
Wave Fixed	3270	3149	2709	2269	2019	1799	1605	1434
Wave Floating	4040	3892	3378	2863	2552	2278	2037	1825
Tidal Stream	3600	3102	2719	2337	2135	1953	1790	1642
Tidal Barrage	3300	3300	3173	3046	2953	2863	2777	2693
Hydro ROR	2250	2185	2017	1849	1777	1707	1640	1575
Solar PV Crystalline - Roof	2850	2470	1715	959	747	606	510	442
Solar PV Crystalline - Ground	2800	2443	1736	1029	825	686	590	520
Solar PV Thin Film - Roof	2650	2318	1621	925	736	608	520	456
Solar PV Thin Film - Ground	2600	2291	1651	1010	818	687	595	528
Geothermal	4725	4655	4389	4123	3841	3591	3371	3177
Nuclear PWR	3200	2650	2569	2488	2470	2452	2435	2417
Nuclear BWR	3000	2604	2508	2412	2395	2379	2363	2347
ASC Coal - Retro Oxy-CCS	2726	2364	2249	2134	2059	1989	1923	1862
ASC Coal - Retro PC-CCS	2770	2376	2267	2158	2100	2045	1992	1940
ASC Coal Oxy-CCS	2761	2398	2281	2164	2088	2017	1951	1889
ASC Coal PC-CCS	2721	2330	2225	2119	2063	2009	1957	1907
IGCC Precomb CCS	2803	2624	2596	2568	2508	2450	2394	2339
CCGT Precomb CCS	881	831	825	818	799	780	763	747
CCGT PC-CCS	1026	951	932	913	895	877	861	845
Advanced AD Sewage Sludge	2605	2438	2232	2026	1910	1803	1703	1609
Food Waste AD	7278	6803	6170	5536	5063	4637	4254	3909
Manure- Slurry AD	5094	4760	4364	3969	3645	3352	3087	2846
Energy Crops AD	6818	6373	5779	5185	4765	4386	4044	3734
Wood- Grate	3350	3129	2957	2785	2650	2523	2403	2289
Wood - Gasification	4300	4010	3533	3056	2749	2480	2244	2036
MSW-SRF Pyrolysis	3119	2908	2587	2265	2069	1893	1735	1593
Wood - BFBC	3828	3828	3445	3062	2886	2724	2573	2434
Wood - CFBC	2178	2178	1978	1778	1678	1585	1498	1418
Waste Wood - CFBC	3190	2987	2824	2660	2519	2388	2266	2151

Least cost scenario	2011	2011 adjusted	2015	2020	2025	2030	2035	2040
Onshore Wind (S)	1450	1413	1324	1235	1182	1132	1084	1039
Onshore Wind (L)	1350	1315	1230	1145	1096	1049	1004	961
Offshore Wind	3088	2715	2523	2331	2231	2136	2045	1959
Wave Fixed	3270	3149	2848	2548	2364	2195	2039	1896
Wave Floating	4040	3892	3731	3569	3403	3245	3097	2956
Tidal Stream	3600	3102	2852	2602	2466	2340	2222	2111
Tidal Barrage	3300	3300	3296	3291	3260	3230	3199	3169
Hydro ROR	2250	2185	2017	1849	1777	1707	1640	1575
Solar PV Crystalline - Roof	2850	2470	1845	1219	991	828	710	623
Solar PV Crystalline - Ground	2800	2443	1965	1487	1342	1220	1119	1034
Solar PV Thin Film - Roof	2650	2318	1729	1140	938	795	694	619
Solar PV Thin Film - Ground	2600	2291	1869	1447	1312	1199	1105	1026
Geothermal	4725	4655	4448	4241	4009	3790	3585	3391
Nuclear PWR	3200	2650	2359	2069	1938	1815	1702	1596
Nuclear BWR	3000	2604	2330	2056	1933	1817	1709	1608
ASC Coal - Retro Oxy-CCS	2726	2364	2249	2134	2059	1989	1923	1862
ASC Coal - Retro PC-CCS	2770	2376	2267	2158	2100	2045	1992	1940
ASC Coal Oxy-CCS	2761	2398	2281	2164	2088	2017	1951	1889
ASC Coal PC-CCS	2721	2330	2225	2119	2063	2009	1957	1907
IGCC Precomb CCS	2803	2624	2596	2568	2508	2450	2394	2339
CCGT Precomb CCS	881	831	825	818	799	780	763	747
CCGT PC-CCS	1026	951	909	867	833	800	770	741
Advanced AD Sewage Sludge	2605	2438	2269	2101	2010	1925	1844	1767
Food Waste AD	7278	6803	6312	5821	5493	5188	4903	4638
Manure- Slurry AD	5094	4760	4450	4139	3919	3713	3519	3338
Energy Crops AD	6818	6373	5921	5468	5184	4918	4668	4435
Wood- Grate	3350	3129	2995	2860	2766	2675	2588	2504
Wood - Gasification	4300	4010	3735	3460	3302	3154	3013	2881
MSW-SRF Pyrolysis	3119	2908	2655	2401	2246	2104	1973	1852
Wood - BFBC	3828	3828	3547	3266	3132	3005	2885	2771
Wood - CFBC	2178	2178	2022	1866	1796	1730	1668	1608
Waste Wood - CFBC	3190	2987	2877	2766	2675	2588	2505	2426

Glossary

AC	Alternating current
ACF	Annual capacity factor
AD	Anaerobic digestion
ASC	Advanced supercritical coal (steam plant)
BFB	Bubbling bed boiler
BoP	Balance of plant
BWR	Boiling water reactor
CC	Carbon capture
CCC	Committee on Climate Change
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CFBC	Circulating fluidised bed combustion
CHP	Combined heat and power
CO_2	Carbon dioxide
CPV	Concentrating photovoltaic
CV	Calorific value (heat content)
DC	Direct current
DECC	Department of Energy and Climate Change
DG	Distributed generation
EPC	Engineering procurement and construction
EU	European Union
FGD	Flue gas desulphurisation
FOM	Fixed operating costs
GJ	Giga joule
GT	Gas turbine
IDC	Interest during construction
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
kV	kilo volt
LCOE	Levelised cost of electricity
MBT	Mechanical biological treatment
MML	Mott MacDonald Limited
MSW	Municipal solid waste
MTBF	Mean time between failures
MW	Megawatt

MWh	Megawatt hour
NPV	Net present value
OEM	Original equipment manufacturer
PV	Photovoltaic
PWR	Pressurised water reactor
R&D	Research and development
ROR	Run of river (hydro)
SCR	Selective catalytic reduction (Nox control)
SRF	Solid recovered fuel
UKERC	UK Energy Research Council
VOM	Variable operating cost
WTG	Wind turbine generator
<Insert term here>	<Insert definition here>
<Insert term here>	<Insert definition here>
<Insert term here>	<Insert definition here>
<Insert term here>	<Insert definition here>