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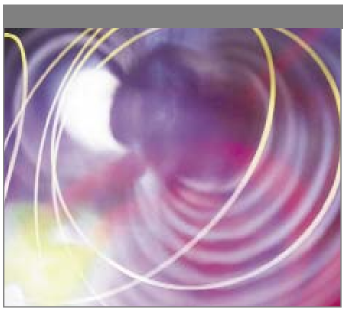

ENERGY

The Cost of Power Generation

The current and future competitiveness of renewable and traditional technologies

By Paul Breeze

Paul Breeze

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Executive summary

Executive summary

Introduction

Since the publication by Business Insights of the last report into the cost of electricity there has been a massive change in global economic conditions as a result of the ramifications of the 2008 banking crisis. This has caused fuel and commodity prices to fall, as well as leading to a severe tightening in lending. The power sector still remains an attractive area for investment but investors are now more cautious than previously. Global warming continues to be a dominant theme but alongside that there is a new pragmatism about fossil fuel combustion which will continue to dominate the power sector for another generation at least. Meanwhile renewable sources of generation continue to advance, led principally by wind power but with solar capacity growing rapidly too, though from a small base.

Capital cost and levelized cost

Electricity is the most important energy source in the modern age but also the most ephemeral, a source that must be consumed as fast as it is produced. This makes modeling the economics of electricity production more complex than carrying out the same exercise for other products. Accurate modeling is important because it forms the basis for future investment decisions. In the electricity sector two fundamental yardsticks are used for cost comparison, capital cost and the levelized cost of electricity. The latter is a lifecycle cost analysis of a power plant that uses assumptions about the future value of money to convert all future costs and revenues into current prices. This model is widely used in the power industry but has some significant failings, particularly in its ability to handle risk. Even so these two measures, together, are the first consulted when power sector investment and planning decisions are to be made.

Risk, volatility and liberalized electricity markets

Production of electricity has always involved an element of risk but this has been extended, and in some cases magnified by the introduction of liberalized electricity markets. One big source of risk is fuel price risk. If an investment is made today based on a predicted cost of natural gas that turns out to be wildly in error because prices soar, as has happened during the past decade, then that investment will be in danger of failing to be economical to operate. Therefore some measure of the risk of fuel price volatility should be included in any economic model. Other risks arise where large capital investment is required in untested technology. Meanwhile the liberalized market has introduced new types of risk more often associated with financial markets. The latter has led to the use of some tools more commonly seen in the financial market for managing electricity sector investment. Of these some of the most interesting today are portfolio management tools.

Historical costs

While economic models may be used to predict the cost of electricity with varying degrees of confidence, the only way those predictions can be judged is by looking at historical costs and trends. For while historical precedent cannot be used to predict what will happen in the future, much future behavior will follow patterns already established in the past. Historical electricity costs and cost trends from different regions will often highlight differences in the way an electricity market is regulated as well as providing evidence of subsidies. Meanwhile a comparison of historical cost predictions with the actual values of the electricity will reveal both how accurate past predictions were and give some insight into the sources of inaccuracy where they exist. Another trend, the learning curve, shows how technology costs change as technology matures and as economies of scale are realized. Historical data of this type is extremely valuable when examining future trends.

Lifecycle analysis, CO_2 emissions and the cost of carbon

Economic models discussed in the first three chapters of the report provide one yardstick by which the performance of a power plant can be judged but the economic point of view is necessarily limited. There are other analytical techniques that provide a different means by which to judge power plant performance. Like the levelized cost of electricity analysis, they are lifecycle analyses that look at inputs and outputs over the complete lifetime of a power plant from its construction to its decommissioning. In this case however the inputs and outputs measured are often environmental in nature. Lifecycle energy analysis shows how efficient a power plant is at using resources in order to produce electricity. Meanwhile lifecycle emission analysis shows how much pollution a power plant produces for each unit of electricity it generates. Among these latter analyses, lifecycle CO_2 emissions have become a subject of global interest. Carbon emissions are becoming part of the economic equation too, and the cost of emitting a tonne of CO_2 will be an important factor in determining future power plant economics.

Factors which distort the price of electricity

In order to make a meaningful comparison between different power generating technologies, an economic analysis must be based on unrestricted open market costs at every stage of the analysis. However there are a number of factors which will distort the costs and hence affect the price. Structural costs, the costs associated with adapting a network to accommodate renewable generation need to be included in the cost of power from these technologies in order to make any comparison fair. Equally, externalities, the costs to society associated with a wide range of environmental effects of power generation should also be included in a fully equitable analysis. Their inclusion is likely to raise the cost of generation from fossil fuel-fired plants. Subsides exist in most corners of the world. Fuel subsidies, in particular, distort the wholesale price of electricity while tariff subsidies will favor one group of consumers over another. The latter will also encourage excessive use of energy. Tax regimes can also affect technologies differentially, distorting any comparison.

The cost of power

The levelized cost of power remains an imperfect tool for comparing generating technologies but it is probably the best available provided its limitations are taken into account. Current levelized costs and levelized cost trends show overall prices rises over the past decade but some changes in relative cost too. Meanwhile the liberalized energy markets of the world have shown increasing signs of the type of cyclical behavior notable in financial markets. This and other factors have led to questioning of the fitness of the open market model to the provision of low cost stable electricity supplies.

Chapter 1

Introduction

Chapter 1 Introduction

In 2005 Business Insights published a report called The Future of Power Generation which looked at trends in the comparative costs of different types of power generation with a particular focus of how renewable and traditional technologies compared. The first report was updated and expanded in 2008 to reflect the changes that had taken place in the intervening years. This report is the third update and expansion so that the report now represents a broad look at electricity generation costs and at the factors influencing them.

One of the key trends of the previous reports was a rise in the cost of fossil fuels, particularly natural gas which was beginning to make gas-fired power generation expensive compared to other types. That trend accelerated into 2008 before the onset of the global financial crisis fed into a global recession and prices of fossil fuels slumped.

In theory this should adjust the economic balance in favor of fossil fuel generation but at the beginning of 2010 there were signs that oil prices were beginning to rise sharply again as global economic activity grew. Against this, the increased attention being paid in the US to extraction of natural gas from shales has expanded US natural gas production and could herald a new era of gas price stability in that market at least.

Coal-fired power generation accounts for around 40% of global power generation and represents the most important source of electricity in use today. It is also the most polluting. Environmental concerns over global warming mean that coal-fired plants have become a particular target for concern but a new pragmatism is beginning to enter this debate based on the realization that coal combustion must continue to form the foundation of the power generation industry for at least another generation. With this pragmatism there is an increasing acceptance by both environmentalists and generators that the future for coal combustion is carbon capture and storage.

The previous reports highlighted a growing optimism within the nuclear industry that nuclear power was on the verge of a renaissance. In 2010 that renaissance has yet to appear. This may be a temporary setback caused by the economic recession but equally it may represent a reluctance to invest in nuclear plants because of a lack of confidence in the new generation of nuclear plants being proposed for construction.

Renewable generation is still seen as the main alternative to fossil fuel generation of electricity and the main new renewable, wind power has continued to expand rapidly with installed global wind capacity reaching 159GW at the end of 2009. Most of this expansion is in onshore wind capacity but offshore capacity is growing too. Solar capacity is expanding rapidly as well, but from a much lower base. Both have probably been limited by manufacturing capacity but even so the rate of growth has been impressive.

An issue that was highlighted in the previous report was the operation of liberalized electricity markets. These show signs of behaving like financial markets with price swings and volatility which was absent previously. This type of behavior continues and can have a significant impact on economic behavior. Additionally there are now growing concerns about the way investment decisions are made in a liberalized market and questions about the suitability of the liberalized market model as it stands to meet national needs.

These issues and trends form the background to this new report. As with the earlier reports, the focus of the report will be on baseline economic costs and on the models used to determine the relative cost of new generating technologies. Risk is becoming an important issue too and this will be examined carefully. The environmental impact of power generation, as with other industrial activity, is coming under increasing scrutiny and environmental measure of performance of power generation technologies will be highlighted alongside the economic measures.

Chapter 2

Capital cost and levelized cost: the traditional approach to estimating the cost of power

Chapter 2 Capital cost and levelized cost: the traditional approach to estimating the cost of power

Introduction

Electricity is undoubtedly the most important energy source in the modern world; indeed electricity is what makes the world modern. All the facilities and devices that developed countries rely upon and developing countries seek, from lighting to the most sophisticated electronic devices, require electricity to operate. At the same time electricity is the most fleeting of all types of energy, so difficult to store that it must normally be consumed as soon as it is produced. These two factors make electricity both the most significant and also one of the most difficult products to understand economically.

The cost of a unit of electricity depends on a large number of different factors. Key among these is the cost of the power plant in which it is produced. This cost will be a compound of the basic installed or 'overnight' cost of the generating plant plus the cost of repayments on any loans taken out in order to finance construction of the plant. Once the plant begins operating there are operational and maintenance costs to take into account. As with capital costs these vary with the type of plant being considered. On top of this there is also the cost of any fuel required by the plant in order to produce electricity. Fuel costs apply to fossil-fuel fired plants, to nuclear power plants and to biomass-fired plants but not to most renewable plants.

In the case of the majority of manufactured goods this would account for the bulk of the cost associated with the product. However because of the nature of electricity its delivery from the power plant to the consumer involves significant cost too. The grid system which has evolved to deliver power is a complex and sophisticated network that must always be kept in balance so that the power delivered into the network is the same, within small tolerances, as the power being taken out. Since the network has no control over power demand it must be capable of changing supply rapidly in order to meet any changes in demand.

Some types of power generating plant can change the amount of electricity they produce quickly to meet such shifts. Others, generally the ones that are cheapest to operate, cannot change output rapidly. Thus, in order to maintain overall grid balance while at the same time minimizing costs, a system will normally have a foundation of cheap base-load power plants that operate all the time together with a range of other, more expensive plants that are called into service intermittently as demand changes. Base load power plants include coal-fired plants and nuclear power plants as well as some combined cycle power plants (though these can often cycle if necessary). Small gas turbines are the most common type of peak power plant.

In addition to variations in demand, some types of power plant have a variable output. These are renewable plants such as hydropower, wind, marine and solar power plants. Normally the output from such plants must be used when it is available, otherwise it is wasted. A network must have strategies for maintaining balance when output from these plants changes. One of the best ways of achieving this is by including energy storage on the network. There are a number of technologies available for storing both small and large quantities of electrical energy[1] but they are not widely used today. Hydropower plants with reservoirs can also be used in a similar way to support intermittent renewable sources.

The cost of a unit of electricity is determined by a combination of the costs associated with the production of the power and those associated with its delivery. The cost of each unit delivered can be broken down into elements reflecting the cost of each, plus the margin added at each stage to generate revenue and profit. Historical costs of electricity can be recorded and charted. However, businesses and economies are not interested in what they paid yesterday for electricity. What they generally need to know is what they are going to have to pay tomorrow. Equally, power generating companies and grid operators want to know what will be their least costly option for the generation and delivery of future power while governments may be seeking to frame their policies in order to ensure future stability of supply.

In order for any of these aims to be achievable, the future cost of electricity must be predicted. This means that the energy supply system must be modeled. The complex nature of the electricity network makes this an extremely difficult task to achieve. However various strategies have become established which allow future costs to be computed and investment decisions made. The two most important of these are capital cost estimates and calculation of the levelized cost of electricity.

Capital cost is important because it represents the amount that must be found at the outset to finance a power plant. In a liberalized electricity market where electricity companies must make a profit for their shareholders, the capital cost will often be a key factor in deciding what type of plant to invest in. The plant with the lowest capital cost will often appear the most attractive, even if the technology may not produce the cheapest electricity over the long term.

Levelized cost, meanwhile, attempts to predict what the long term cost of electricity will be. The model, which was developed during the era of vertically integrated regulated and state-owned utilities, has many shortcomings as an accurate predictor of future electricity prices. In particular it fails to take adequate account of risk. However as a means of making a comparison between different generation options it remains the single most widely used tool. Capital cost and levelized cost will form the subject of this chapter while the next will examine some of the strategies being used to introduce risk into the model.

Capital costs

The capital cost of a power generating plant can vary widely depending upon the technology. Of the established and conventional technologies including nuclear, fossil fuel and hydropower-based generating plants the cheapest by a wide margin is the gas turbine. The overnight cost of a simple gas turbine power plant may be as low as \$600/kW. This includes the cost of installation and all the ancillary equipment. The actual gas turbine itself probably costs much less than this. There is unsupported evidence that large frame gas turbines for combined cycle plants may be purchased for less than \$200/kW[2]. At the other end of the scale, a modern nuclear plant is likely to cost over \$3,000/kW (some current estimates suggest twice this). Among the advanced and renewable technologies, geothermal power is probably the cheapest at around \$1,700/kW, with wind close behind, while a fuel cell will cost close to \$5,000/kW and a solar photovoltaic power plant nearly \$6,000/kW.

The last two technologies, solar cells and fuel cells, are new technologies that are still under development. The prices of both can be expected to fall relative to their competitors as the technology matures further. Gas turbines, on the other hand are based on mature technology and the scope for further price reduction is small. However, all three are technologies that allow preconstructed modules to be bought 'off-the-shelf' ready for installation.

Gas-fired combined cycle plants are modular in nature, with many of the components brought to site ready-constructed. This helps make them cheap to build. In contrast, much of a nuclear power station must be constructed at the site. This involves considerable material and labor costs and these costs are part of the reason why nuclear power plants are expensive (there are others). A coal fired plant, like a nuclear plant, involves significant on-site construction and this again increases the cost.

There is also a fundamental difference between on the one hand fossil fuel-fired and nuclear power plants and on the other those based on renewable sources of energy. While the former have fuel costs, the latter have none. This does not affect their capital costs but it makes an enormous difference when calculating the cost of electricity produced by each plant. This is reflected in the levelized cost (see below).

Table 2.1 shows estimates of capital cost for a range of power generating technologies based on figures published by the US Energy Information Administration (US EIA). These figures are for plants ordered in 2009 with the online date as shown in the table. The lead time depends on both the complexity and the level of maturity of the technology. An onshore wind farm can be installed within a year while lead time for a nuclear power plant is seven years. Costs in the table are in 2008$.

The cheapest technology to install is an open cycle gas turbine. An advanced unit of this type has an installed cost of $617/kW while a conventional unit of the same type has an installed cost of $653/kW. Open cycle gas turbines are expensive to operate and generally only used for peak power service. However, gas turbine combined cycle power plants form a mainstay of many electricity networks. According to the EIA, an advanced combined cycle plant costs $897/kW and a conventional plant $937/kW. These represent the cheapest base-load fossil-fuel fired power plant option available today.

Coal-fired power plants are, in comparison, much more expensive. A pulverised coal-fired power plant fitted with conventional emission control systems is expected to cost $2,078/kW, well over twice the price of a combined cycle plant. A more advanced, integrated gasification combined cycle (IGCC) power plant based on coal combustion has a predicted cost of $2,401/kW, higher still.

The future of fossil-fuel combustion is likely to involve the use of carbon capture and sequestration (CCS) in order to meet international targets to restrict global warming of the atmosphere. This will increase significantly the capital cost of such plants. The cheapest such option in Table 2.1 is an advanced combined cycle plant with CCS which is expected to cost $1,720/kW to install for startup in 2016. A coal-fired IGCC power plant with CCS, again for startup in 2016, is expected to cost $3,427/kW, virtually twice as much as the gas-fired plant.

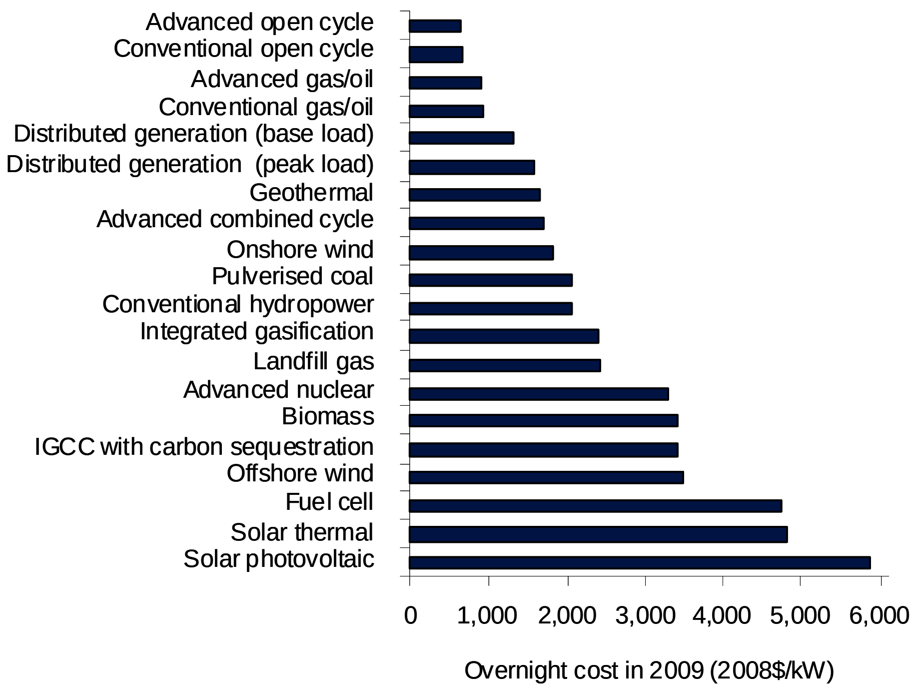
Nuclear power represents a feasible alternative today for new generating capacity with many governments looking at the possibility of either starting or expanding their nuclear fleets. In Table 2.1, a new nuclear power plant based on the advanced technologies currently being offered by nuclear power companies would cost $3,308/kW to install. This is comparable costs for coal-based IGCC plant with CCS.

Table 2.1: EIA overnight capital cost of power generating technologies, 2009

	Year online (for order date of 2009)	Unit capacity (MW)	Overnight cost in 2009 (2008$/kW)
Pulverised coal power plant with scrubber	2,013	600	2,078
Integrated gasification combined cycle coal	2,013	550	2,401
IGCC with carbon sequestration	2,016	380	3,427
Advanced open cycle gas turbine	2,011	230	617
Conventional open cycle gas turbine	2,011	160	653
Advanced gas/oil combined cycle	2,012	400	897
Conventional gas/ oil combined cycle	2,012	250	937
Advanced combined cycle with carbon sequestration	2,016	400	1,720
Advanced nuclear	2,016	1,350	3,308
Distributed generation (base load)	2,012	2	1,334
Distributed generation (peak load)	2,011	1	1,601
Onshore wind	2,009	50	1,837
Offshore wind	2,013	100	3,492
Conventional hydropower	2,013	500	2,084
Biomass	2,013	80	3,414
Landfill gas	2,010	30	2,430
Geothermal	2,010	50	1,666
Fuel cell	2,012	10	4,744
Solar thermal	2,012	100	4,798
Solar photovoltaic	2,011	5	5,879

Source: EIA[3] Business Insights Ltd

Figure 2.1: EIA overnight capital cost of power generating technologies (2008$/kW), 2009



Source: EIA

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Distributed generation is represented in the table by two options, one in which local generating capacity is used for peak shaving and the second where it is used for base load generation. The actual technology is not specified but it might be a mixture of renewable sources such as solar photovoltaic (pV) or wind with some form of energy storage and a gas engine. The installed cost of the peak load distributed generation is $1,601/kW while base load distributed generation will cost $1,334/kW based on these predictions. Fuel cells, another option for distributed generation, have an estimated cost of $4,744/kW.

A range of renewable technologies are included in Table 2.1. Of these, the lowest cost is geothermal power with an estimated capital cost of $1,666/kW. This is followed by onshore wind with an estimated capital cost of $1,837/kW. The latter is also the technology that can be brought online the most rapidly. Offshore wind is nearly twice as expensive at $3,492/kW. Conventional hydropower is slightly more expensive than onshore wind at $2,084/kW. Power plants burning landfill gas, which are often classed as renewable, have an installed cost of $2,430/kW. These installations, which exploit the methane gas generated in landfill waste sites, are normally based on piston engines designed to burn the gas.

The other renewable technologies included in the table are significantly more expensive. Biomass, at $3,414/kW has the lowest cost of these and is, like nuclear technology, comparable to the cost of a coal-fired power plant with CCS. Biomass power plants are considered carbon neutral and so do not need carbon capture equipment. A solar thermal plant is expected to cost $4,798/kW while a solar photovoltaic plant is the most expensive of all with a capital cost of $5,879/kW.

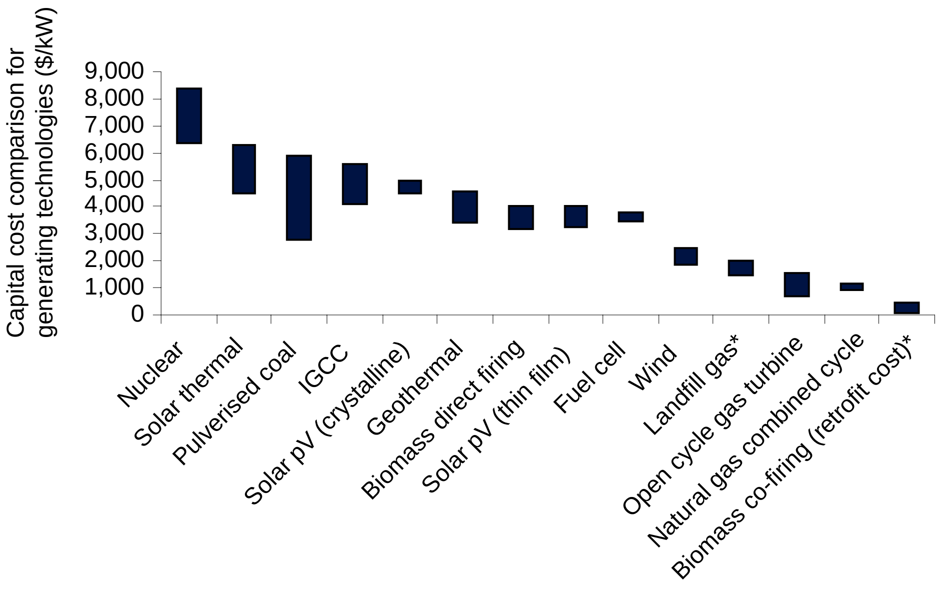
A second set of capital cost estimates for power plants is shown in Table 2.2. The figures were produced by Lazard[4]. Column one of the figures in Table 2.2 is derived from Version 2 of the company's Levelized Cost of Energy Analysis published in 2008 and column two is taken from Version 3, published in 2009. The changes between the two sets reflect both changes in commodity prices over the twelve months and changes in the methodology. The estimated capital costs of coal-based technologies in Table 2.2 are higher than those from the EIA. The cost of a standard pulverised coal plant is put at around $2,800/kW rising to $5,925/kW when carbon capture is added (this figure does not include the cost of carbon storage). IGCC costs, meanwhile, are between $4,075/kW and $5,550/kW depending on whether carbon capture is included. Likewise, the cost of a combined cycle power plant, at $950/kW to $1,175/kW is higher than in Table 2.1, while the cost of a new nuclear plant, at between $6,325/kW and $8,375/kW is significantly higher than that in Table 2.1. Of fossil-fuel based plants only a fuel cell plant, with an estimated cost of $3,800/kW, has a lower cost in Table 2.2.

Table 2.2: Lazard capital cost comparison for generating technologies ($/kW), 2009

	Lazard 2008	Lazard 2009
Pulverised coal[5]	2,550-5,350	2,800-5,925
IGCC[6]	3,750-5,050	4,075-5,550
Natural gas combined cycle	900-1,100	950-1,175
Open cycle gas turbine	650-1,500	675-1,575
Nuclear	5,750-7,550	6,325-8,375
Biomass direct firing	2,750-3,500	3,150-4,000
Biomass co-firing (retrofit cost)	50-500	-
Landfill gas	1,500-2,000	-
Fuel cell	3,800	3,800
Geothermal	3,000-4,000	3,425-4,575
Wind	1,900-2,500	1,900-2,500
Solar thermal	4,500-6,300	4,500-6,300
Solar pV (crystalline)	5,000-6,000	4,500-5,000
Solar pV (thin film)	2,750-4,000	3,250-4,000

Source: Lazard[7] Business Insights Ltd

Figure 2.2: Lazard capital cost comparison for generating technologies ($/kW), 2009



* Note 2008 figures are used for Landfill gas and Biomass co-firing (retrofit cost)

Source: Lazard Business Insights Ltd

Of the renewable sources of energy, a geothermal plant is estimated to cost twice as much by Lazard as by the EIA. Onshore wind, at $1,900/kW to $2,500/kW, is broadly similar at the lower end of the range to the EIA estimate, and solar thermal ($4,500-$6,300/kW) is also similar at the lower end while solar PV is significantly cheaper at $4,500/kW to $5,000/kW.

The cost of a directly fired biomass power plant is put at $3,150-$4,000/kW in Table 2.2, broadly similar to the figure in Table 2.1. The table also includes a cost from 2008 for co-firing of biomass in a conventional coal-fired power plant. The retrofit cost of this technology was put at $50-$500/kW.

The costs in the second column of Table 2.2 are all higher than in the first column. This represents both changes in estimates as well as changes in commodity prices. Table 2.3 shows more extensive historical price trends with a series of sets of capital cost estimates from the EIA for a wide range of technologies based on reports published between 2003 and 2010. These give a better indication of the overall changes in costs that have occurred during this decade.

As expected, costs for all the main conventional technologies have risen, some steeply. The cost of a pulverised coal-fired plant has risen from $1,079/kW to $2,078/kW over the period covered by these reports (the figures in these reports are for the year previous to the publication year, so the figures for the report published in 2010 refer to 2009, and are the same figures as those in Table 2.1.) while the cost of an IGCC plant increased from $1,277/kW to $2,401/kW. In each case this represents an almost doubling of capital costs.

Similar steep rises are seen in the cost of open cycle gas turbines but the rate of rise in the cost of combined cycle plants is some what slower, so that the cost of an advanced combined cycle plant has increased by 59% over the six year period compared to 168% for an advanced open cycle gas turbine and 93% for a pulverised coal plant. Similar prices rises can be seen for plants with carbon sequestration and for an advanced nuclear plant.

Table 2.3: EIA overnight capital cost trends for power generating technologies ($/kW), 2010

EIA Annual energy outlook report year	2003	2005	2007	2008	2009	2010
Pulverised coal power plant with scrubber	1,079	1,134	1,206	1,434	1,923	2,078
Integrated gasification combined cycle coal	1,277	1,310	1,394	1,657	2,223	2,401
IGCC with carbon sequestration	-	1,820	1,936	2,302	3,172	3,427
Advanced open cycle gas turbine	230	356	379	450	604	617
Conventional open cycle gas turbine	160	376	400	476	638	653
Advanced gas/ oil combined cycle	563	517	550	543	877	897
Conventional gas/ oil combined cycle	510	540	574	683	917	937
Advanced combined cycle with carbon sequestration	-	992	1,055	1,254	1,683	1,720
Advanced nuclear	1,750	1,694	1,802	2,143	2,873	3,308
Distributed generation (base load)	766	769	818	972	1,305	1,334
Distributed generation (peak load)	919	924	983	1,168	1,566	1,601
Wind	938	1,060	1,127	1,340	1,797	1,837
Conventional hydropower	-	1,319	1,364	1,410	2,038	2,084
Biomass	1,569	1,612	1,714	2,490	3,339	3,414
Geothermal	1,681	2,960	1,790	1,057	1,630	1,666
Fuel cell	1,850	3,679	3,913	4,653	4,640	4,744
Solar thermal	2,204	2,515	2,675	3,499	4,693	4,798
Solar photovoltaic	3,389	3,868	4,114	5,380	5,750	5,879

Source: EIA[8] Business Insights Ltd

The main renewable technologies in Table 2.3 show a similar trend with the exception of geothermal energy where the estimated cost in the 2010 report, $1,666/kW is actually marginally lower that the figure of $1,681/kW from the 2003 report. Wind, biomass and the solar technologies all show significant cost increases over this period, often close to doubling in seven years.

Prices would generally be expected to rise over time for mature technologies but it might have been expected that costs of some of the developing technologies might fall. This is clearly not the case, though it should be remembered that these are all predicted costs for future power plants, not actual costs. As we will see in Chapter 4 there is evidence for a fall in price for some new technologies over time but this is masked in Table 2.3 by the overall increase in manufacturing costs.

In the case of almost all the technologies in Table 2.3, prices have risen steadily year upon year until 2008. However, there is a step change between 2008 and 2009 in most of the sets of figures. This reflects the steep rise in commodity prices that was seen in 2007 when costs of metal such as iron and copper as well as many other commodity costs peaked. The changes in costs between the 2009 and 2010 reports, on the other hand, are much smaller marking the point when the global recession bit. However, care should be taken when reading the figures because they are calculated for the US market and reflect fluctuations in the value of the US dollar against other major currencies as well as global labor and commodity cost variations. Even with this caveat, however, they show clearly how prices of all technologies have been increasing during most of this decade.

Regional capital cost fluctuations

Capital costs for the construction of different types of power plant are likely to vary independently of fluctuations in the value of currencies. Those types of plant that are based on an 'off-the-shelf' prime mover such as gas turbine or wind turbine installations should cost a similar amount anywhere in the world because the units upon which they are based are traded like a commodity and there is competition between manufacturers producing similar products for the same market. These prices may be distorted by subsidies to local manufacturers but that aside they should be similarly priced everywhere, at least in their home currency.

Other types of power plant involve considerable on-site construction. As we have seen, these include nuclear power plants, coal-fired power plants and large hydropower projects. The capital cost of plants of this type will depend heavily on local labor costs. Thus costs may be lower where labor is cheap.

Another factor that will affect cost will be the extent to which equipment must be imported. Gas turbines, for example, are specialized high technology machines that are only manufactured by a few companies. Therefore power generating companies in most countries of the world that are hoping to install a gas turbine power plant will have to buy the unit from abroad. This will necessitate the availability of foreign currency with which to pay for the transaction and this may well affect the overall cost. In some cases this may also limit the type of power plant that can be built if the necessary foreign currency is not available.

Capacity factor

The capital cost of a power plant as indicated in the tables above refers to the cost to install one kilowatt of generating capacity. The generating capacity referred to is the rated capacity of the power plant (often called its nameplate capacity). However in most cases a power station will not be able to produce power at its rated capacity continuously. The Capacity Factor is a figure which takes account of this discrepancy between nameplate capability and actual output.

The capacity factor of a power station is the ratio of the actual power output of the plant over one year compared to the amount of electricity it would produce if it ran continuously at its rated capacity for a year (normally expressed as a percentage). So, for example, a 100MW power plant that ran continuously for a year but at 50MW would have a capacity factor of 50%. Similarly a gas turbine that operated for only 6 hours each day, 365 days a year would have a capacity factor of 25%.

No power plant is capable of operating with a capacity factor of 100%. All require regular maintenance and over time parts will have to be replaced, requiring the plant to stop. The operation of most fossil fuel and nuclear power stations is limited by just these factors. In between these interruptions to service they can normally operate continuously. Many renewable energy technologies, by contrast, rely on intermittent sources of energy. In this case there is an intrinsic limit to the capacity factor. This must be taken into account if one wants to compare capital costs of different types of technology.

Table 2.5, below, includes typical capacity factors for a variety of different power generation technologies. As the figures show, nuclear power has one of the highest capacity factors of all types of power plant in regular service at around 90%. This is partly a reflection of economics since nuclear plants operate most economically when run continuously. By comparison the capacity factor of coal-fired power plants is around 85% and that of natural gas combined cycle plants is 87%. In fact these figures may be optimistic; the average capacity factor for US coal-fired plants is 68%. Meanwhile open cycle gas turbines have a typical capacity factor of 30%, reflecting their use for peaking rather than base load service.

Of the renewable technologies, only geothermal can compete with the conventional technologies in terms of capacity factor, with a typical figure of 90%. The capacity factor of a biomass plant at 83% is similar to that of a coal-fired power plant which is to be expected since they use broadly the same type of technology.

Hydropower has a capacity of factor or around 50%. This is a result of the variations in water flows from season to season as well as the vulnerability of hydropower to low water conditions during droughts. Wind power is perhaps the most intermittent of the renewable sources with constant short term fluctuations in output as the wind strength changes. As a consequence the capacity factor for a new onshore wind plant is likely to be around 34% and for an offshore plant 39%. These figures are higher than most wind farms achieve today, although some can match this level. A solar thermal plant might be expected to achieve a capacity factor of 31% while the typical capacity factor of a utility scale solar pV plant is 22%.

The capacity factor of a power plant has a significant impact on the economics of its operation. A plant that can run continuously will produce more power over the course of a year and it will provide with it more reliably. Power plants such as wind farms and marine power units which rely on an inherently intermittent and unpredictable source of energy both produce less power over the year for each unit of nameplate capacity and produce it less reliably. However capacity factor alone does not tell the whole story and the value of such intermittent sources of power is normally better indicated by a number called the capacity credit of the plant. This will be discussed more fully in Chapter 6.

Financing capital cost

The cost of building a power station must normally be met at the outset of the project, or at least as soon as it is completed. In most cases today this will involve raising a loan to be paid back from the sale of the electricity the power station produces. The length over which this loan is repaid will depend on its size and on the type of power plant being built. Normally it is likely to be no more than 20 years. This is less than the expected lifetime of most modern power stations.

Gas turbine and coal-fired power plants are expected to have a lifetime of around 30 years, though in some cases this may be extended with a major refit. Nuclear power plants are now likely to operate for at least 40 years, some probably longer. Large hydropower plants can have lifetimes in excess of 50 years provided the site has been well chosen.

When the loan period does not coincide with a realistic lifetime for a plant, the result is a repayment schedule that can adversely affect the economics of the project by raising the cost of the electricity it generates. If, for example, a hydropower plant with a life of 50 years can only raise a construction loan for repayment over 20 years, then the electricity from this plant during the period of the loan repayment will be much higher than it would be if the loan were over, say, 40 years. This is especially true of renewable technologies which are generally capital intensive because loan repayments often form the major part of the cost of the electricity the plant generates. In contrast, a loan for a cheap gas turbine will be much easier to repay, even though operational costs may be much higher.

There appears to be no means of avoiding this distortion of economics under the conditions which operate in financial markets today where investors demand short repayment periods and high returns. The fact that it affects capital intensive technologies more severely does unreasonably handicap some renewable technologies, however.

There are some signs that this is being recognized today at a governmental level. In the UK, which pioneered the full liberalization of the electricity sector in the 1980s, there is a growing awareness that the current market structure is not capable of providing the infrastructure necessary to ensure a stable future supply of electricity. A recent discussion document from the UK regulator[9] has opened a debate that might have far reaching consequences, not just in the UK but much farther afield too.

The levelized cost of electricity model

Capital cost (and the loan repayment rate associated with capital cost) is a key factor influencing the cost of electricity from a power station. There are others. As already noted above, fuel costs will be important in fossil-fuel fired power plants. Operation and maintenance costs associated with a plant will also be significant, particularly in those which use components such as gas turbines which require regular major overhauls.

How, then, does one set about combining all these elements in order to estimate the future cost of electricity from a proposed power station? The answer is by using some form of economic modeling, and the one that has found most favor in the past is the levelized cost estimate. This involves calculating the total cost involved in building and operating the plant over its lifetime, broken down for each year of its operation. These annual costs are then 'discounted' to convert them into the 'present value' a figure which reflects the expected reduction in the value of money over the lifetime of the project (see Figure 5.23). All the annual discounted sums are then added together to provide a figure in today's money for the total costs associated with the plant. This figure is divided by the estimated total output of the plant over its lifetime and the resulting number is the levelized cost of electricity from the station, again in today's prices.

Levelized costing is a method that was favored in the past by monopoly, integrated, often state-owned, utilities generating electricity from large power plants based on coal, hydropower or nuclear technology. When these organizations expanded their generating base, the cost of a new plant was often met without resorting to financial markets for loans, of if loans were sought their repayments would be guaranteed by government, so securing favorable rates. Under these relatively stable conditions, the levelized cost represented a useful tool for determining which technology might offer the best future performance. However a decision might also be influenced by the need to support a particular industry (coal, for example) or to achieve a particular combination of technologies in the supply system.

The electricity utility industry today is very different to the one in which these large integrated utilities operated. A competitive market pitching one generator against another combined with the need to fund construction from the international financial markets has changed the way in which investment decisions are made. And these differences provide significant grounds on which to question whether the levelized cost approach continues to remains valid.

One of the most important areas of dispute concerns use of a discount rate. The basis for using a discount rate, that the value of money changes over time, is sound. But this does not provide a clear indication of what discount rate should be used. And as the figures in Figure 5.23 show, the precise value chosen has an enormous effect on the end result.

Interest, discount rate and present value

If A has $100 and B wants to borrow $100 for a year, A may be prepared to lend B $100 provided B repays the $100 plus an additional sum - say $10 - to reflect A's inability to use the $100 immediately. This additional $10 is the interest or discount. The sum reflects the value A places on having the money to spend today rather than in one year's time. In effect it says that for A, $110 in one year's time is worth the same amount as $100 today. (In economic terms, the present value to A of $110 in one year's time is $100.) A similar calculation, but involving compound interest calculation, can be applied to calculate the sum B must repay to A in order to keep the loan for two years or ten years. Thus A will require B to repay $121 in two years and again, by reversing the equation we can say that A considers the present value of this $121 to be $100.

Calculations of loan repayments and of present value are extremely sensitive to the discount rate chosen as the basis for such a calculation as the figures in the table below show. One million dollars in ten years time has a present value of $620,000 at a discount rate of 5%; at a discount rate of 10% this falls to $390,000.

Figure 2.3: Present value of one million dollars as a function of discount rate

Year	Present Value, $ (5% discount rate)	Present Value, $ (10% discount rate)
0	1,000,000	1,000,000
5	780,000	610,000
10	620,000	390,000
15	500,000	250,000

Source: Vanderbilt Law Review[10] Business Insights Ltd

This concept of present value is widely used to estimate the total costs involved in a power generating project. This is preformed by assuming a lifetime for the plant, then for each year calculating the total costs to finance the loan, buy fuel and operate and maintain the facility. A discount rate calculation similar to that used to calculate the figures in the table above are then used to convert the future cost into a present value. The present values of costs for all the years of the lifetime of the plant are then added together to give an overall figure for the present value of the plant. This equates to the total cost today of the station and its operation.

It is clear from the figures in Figure 5.23 that the larger the discount rate, the smaller the estimated costs in future years of a power plant built today. Discount rates of 5%, 7% or 10% are routinely used when calculating levelized costs, though such elevated rates can often appear highly inappropriate, particularly today when interests rates in many parts of the world are at or close to zero. There is also a more detailed criticism, that the same discount rate should not be applied to all future costs. Critics have argued that while costs which are relatively stable and risk free can be discounted at a high rate others, and particularly fuel costs, should be discounted at a lower rate to reflect the risk associated with such fluctuations. These arguments will be examined in more detail in the next chapter. So, with these caveats in mind, we will now examine some recent levelized costs of generation from a range of different technologies.

Levelized cost estimates

Table 2.4 contains levelized costs from the two reports from Lazard quoted above. These costs are for the US market and take into account any tax breaks and incentives that might be available in the US. Therefore they are not directly transferable though in many cases similar advantages will be available elsewhere.

The ranges of costs in the table reflect a wide degree of uncertainty. In the case of the principle base load fossil fuel technologies this is because the highest costs are for a plant with 90% carbon capture while the lower costs are without carbon capture.

Taking the figures in Table 2.4 as a whole, the cheapest cost option will be an onshore wind plant which has a predicted levelized cost of \$57-\$113/MWh. A geothermal plant with a levelized cost of \$58-\$93/MWh is marginally cheaper but geothermal fields are not widely available whereas wind is, so in many cases the former will not be an option. Direct fired biomass also appears to be competitive on this estimate, with a levelized cost of \$65-\$113/MWh. Again, however, biomass capacity is restricted by the availability of suitable fuel feedstock and so biomass is not capable of providing a large generating capacity today, though it may in the future.

The cheapest fossil fuel option is a natural gas combined cycle power plant which is estimated to be capable of providing power at between \$69/MWh and \$96/MWh. Power from a pulverised coal-fired plant is predicted to cost between \$98/MWh and \$144/MWh, the upper figure representing a plant with carbon capture. Similarly, an IGCC plant has a predicted levelized cost of \$119-\$141/MWh. Here the pulverised coal plant is cheaper without carbon capture but the IGCC plant becomes marginally cheaper with carbon capture.

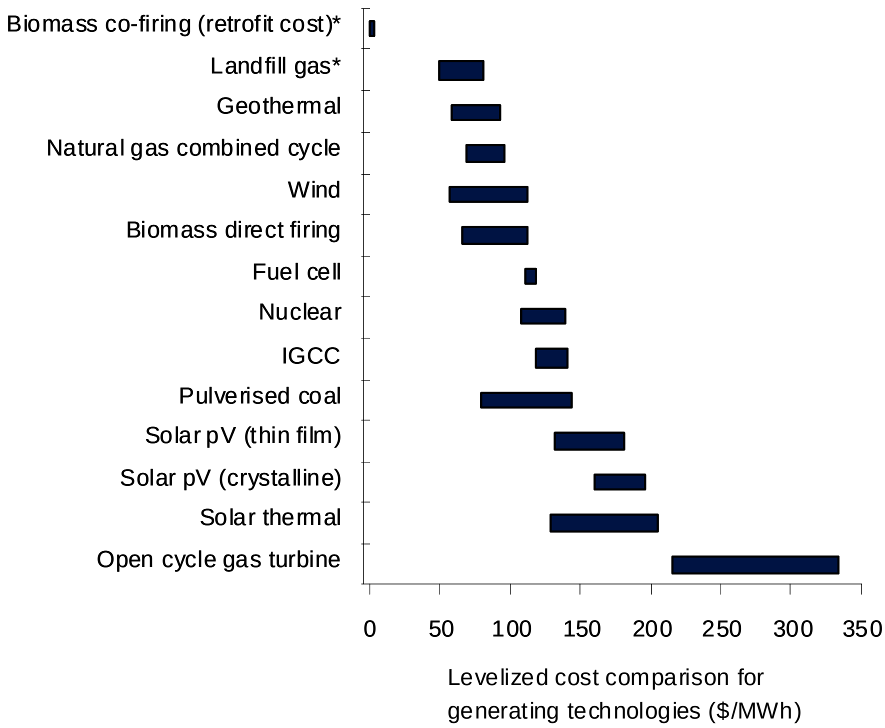
Based on the Lazard figures, a nuclear plant will generate for between \$107/MWh and \$138/MWh, significantly cheaper than either coal plant with carbon capture. Solar thermal costs are put at between $129/MWh and $206/MWh much cheaper than a solar pV plant using crystalline silicon ($160-196/MWh) but similar in price to solar pV using thin film technology ($131-$182/MWh).

Table 2.4: Lazard levelized cost comparison for generating technologies ($/MWh), 2009

	Lazard 2008	Lazard 2009
Pulverised coal[11]	74-135	78-144
IGCC[12]	104-134	119-141
Natural gas combined cycle	73-100	69-96
Open cycle gas turbine	221-334	216-334
Nuclear	98-126	107-138
Biomass direct firing	50-94	65-113
Biomass co-firing (retrofit cost)	3	-
Landfill gas	50-81	-
Fuel cell	115-125	111-119
Geothermal	42-69	58-93
Wind	44-91	57-113
Solar thermal	90-145	129-206
Solar pV (crystalline)	128-154	160-196
Solar pV (thin film)	96-124	131-182

Source: Lazard[13] Business Insights Ltd

Figure 2.4: Lazard levelized cost comparison for generating technologies ($/MWh), 2009



*Note 2008 figures are included for Biomass co-firing (retrofit cost) and Land fill gas

Source: Lazard Business Insights Ltd

Costs of all the technologies in Table 2.4 rose between the 2008 and the 2009 version of the report with the exception of combined cycle technology and fuel cells which appears to have become slightly more competitive. However the biggest overall cost rises are associated with the renewable technologies, wind, geothermal and solar.

A second set of figures showing the levelized cost of electricity of a wider range of technologies is presented in Table 2.5. These figures were developed by the US EIA and published in their 2010 Annual Energy Outlook. The figures are all for plants entering service in the same year, 2016. The table also shows typical capacity factors for the different technologies and a cost associated with transmission of power from each plant. The costs do not include tax incentives or other advantages and so provide a better overall guide to the production costs of each technology. (However they are based on estimated costs for fuel in the case of fossil fuel plants, which may have a significant bearing on their ranking. See Chapter 3 for more about this issue.)

The cheapest source of power by a significant margin in Table 2.5 is a combined cycle power plant. According to the EIA a conventional plant can generate power for $83/MWh and an advanced combined cycle plant for $79/MWh. This is $17-$21 cheaper than a pulverised coal-fired plant with a cost of $100/MWh. An advanced coal plant, meanwhile, is expected to generate electricity for $111/MWh.

By the middle of the second decade of the century most power generators ought to be considering the construction of low carbon emission power plants. Again, the cheapest fossil fuel option is a combined cycle power plant with CCS, with an estimated levelized cost of $113/MWh. An advanced coal plant with CCS is $26/MW more expensive at $129/MWh. Both these costs, but especially the gas plant cost will depend critically on the cost of gas. However an advanced nuclear plant, which can be expected be less vulnerable to fuel price fluctuations, can generate power for $119/MWh according to the EIA, making it competitive with the fossil fuel options.

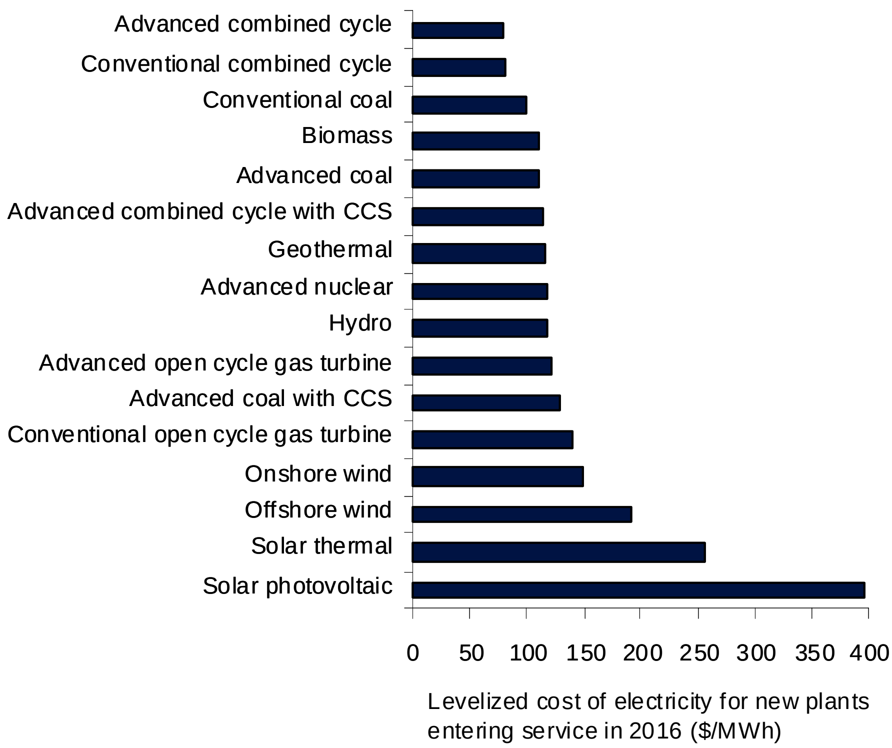
Table 2.5: EIA levelized cost of electricity for new plants entering service in 2016 ($/MWh)

	Capacity factor (%)	Transmission investment ($/MWh)	Total system levelized cost ($/MWh)
Conventional coal	85	3.6	100.4
Advanced coal	85	3.6	110.5
Advanced coal with CCS	85	3.9	129.3
Conventional combined cycle	87	3.6	83.1
Advanced combined cycle	87	3.6	79.3
Advanced combined cycle with CCS	87	3.8	113.3
Conventional open cycle gas turbine	30	10.8	139.5
Advanced open cycle gas turbine	30	10.8	123.5
Advanced nuclear	90	3	119
Onshore wind	34.4	8.4	149.3
Offshore wind	39.3	7.4	191.1
Solar thermal	31.2	10.4	256.6
Solar photovoltaic	21.7	13	396.1
Biomass	83	3.8	110
Geothermal	90	4.8	115.7
Hydro	51.4	5.7	119.9

Source: EIA[14]

Business Insights Ltd

Figure 2.5: EIA levelized cost of electricity for new plants entering service in 2016 ($/MWh)



Source: EIA

Business Insights Ltd

Of the renewable options in Table 2.5, the cheapest are biomass ($110/MWh) and geothermal power ($116/MWh). Both are competitive with the fossil fuel plants with CCS, and the nuclear plant, but neither is capable of being deployed sufficiently widely to replace anything but a small part of the capacity which either of these other options might supply. Hydropower, with generation costs of $120/MWh is also competitive but opportunities for large hydropower development are rare in the US and in most parts of the developed world. Large hydropower may remain and option in some developing regions, particularly Africa, provided their full potential for social improvement is realized.

Wind, the preferred option for new renewable generation today in many parts of the world is relatively expensive on the basis of the EIA calculation. As Table 2.5 shows, the estimated cost of power from an onshore wind farm is expected to be $149/MWh while that from an offshore farm is put at $191/MWh. Solar sources are more expensive still. Solar thermal power is expected to cost $257/MWh in 2016 and solar pV power $396/MWh. On this basis neither would appear to offer a viable option.

It is worth noting, however, that these figures are averages across the US. As the EIA notes in its report, costs can vary widely particularly for renewable sources. For example the levelized cost of onshore wind upon which the figure in Table 2.5 is based varied from $91/MWh in the best region to $271/MWh in regions where all the best sites had been exploited.

Transmission costs in Table 2.5 are broadly a reflection of the plant capacity factor. Plants with high capacity factors such as nuclear and fossil fuel-fired plants (as well as biomass) have transmission investment costs in the range $3-$4/MWh. As the capacity factor falls, this cost rises so that for a solar photovoltaic plant with a capacity factor of 22%, the transmission investment cost is $13/MWh.

Some somewhat older levelized cost figures are provided by the UK Energy Research Centre (UK ERC) which carried out a study in 2006-7 of published levelized costs of electricity from a wide range of sources, including figures from many different countries. The averages for the most common technologies, based on figures extracted from the various sources included in the study, are shown in Table 2.6 translated into 2006£. What is perhaps surprising is that the three most prevalent technologies in the study - coal-fired, natural gas-fired and nuclear power plants - have very similar costs: £31.2/MWh for a gas-fired plant, £32.2/MWh for a nuclear plant and £32.9/MWh for a coal-fired plant. Renewable generation is represented by wind power which has a significantly higher average generating cost than any of these three.

Table 2.6: Mean levelized costs from published global figures (£/MWh), 2007

	Mean levelized cost (£/MWh)	Standard deviation (£/MWh)
Coal	32.9	9.7
Natural gas	31.2	8.9
Nuclear	32.2	10.5
Wind	39.3	19.6
Offshore wind	48	20

Source: UK ERC[15] Business Insights Ltd

This study also examined how costs vary from country to country. The analysis revealed some striking variations. For example, the levelized cost of electricity from a coal-fired power plant varied from around £15/MWh in South Africa to close to £50/MWh in Japan. In part these figures reflect the availability of coal. South Africa has abundant resources whereas Japan must import all its coal. Nevertheless the range of costs is perhaps unexpected.

The cost of gas fired electricity was also highest in Japan, at close to £55/MWh while the cheapest, not far above £20/MWh was found in New Zealand. Nuclear varied between £15/MWh (Mexico) and £48/MWh (Italy) and onshore wind between around £20/MWh (US) to £80/MWh (Czech Republic).

The data used to compile the figures in the UK ERC study come from many sources and the initial assumptions vary widely. It is difficult, therefore, to draw any firm conclusions from the figures themselves. The authors of the report also point towards the range of factors that a levelized cost calculation does not include such as network costs for different technologies, tax regimes which may affect the value of an investment and the portfolio value of investing in a particular technology even if it is a relatively expensive source of power.

One conclusion that may be drawn is that levelized cost is location specific. A calculation based on the situation in the US will lead to a different result to the same calculation base on the situation in Sweden. But, taking account of the caveats expressed above, levelized cost does offer a starting point for any project evaluation.

Provided its limitations are borne in mind, it still represents a valuable means of deterring which types of project might be viable in a given situation and which might not. But the final decision will probably be based on a range of other factors too. Some of these will be discussed in the next chapter.

Chapter 3

Risk, volatility and liberalized electricity markets

Chapter 3 Risk, volatility and liberalized electricity markets

Introduction

The production of electricity has always involved an element of risk but this has been significantly magnified by liberalization of the industry. This liberalization has made the operation of the electricity market similar is some aspects to the operation of financial markets and with it new types of risk have been introduced.

In a financial market, risk is associated with the value of investments such a shares or bonds. Safe investments are those whose value is not expected to either rise or fall dramatically. Risky investments, on the other hand, may show wild swings in value. In the electricity market the value of an investment can be replaced with the cost of electricity. A safe investment is investment in a power generating facility that reliably produces electricity for a price that does not fluctuate wildly. A risky investment involves a power plant where the cost of the electricity it produces may both rise and fall dramatically.

The quest within the liberalized electricity industry is to find the cheapest source of power. (Since there is an inverse relationship with the financial sector, this is equivalent to seeking the investment that is likely to offer the highest yield.) The cheapest source of power today is often from a natural gas-fired combined cycle power plant. However this also presents one of the riskiest investments because the cost of natural gas can be extremely volatile. A steep rise in gas prices can easily make the cost of electricity from such a power plant uneconomical.

It may not be immediately obvious, but in this market the safest investment is a power plant based on renewable energy such as wind, hydro or solar. While all these plants present higher levels of unreliability than a natural gas plant, they can be statistically relied upon to produce a certain amount of electricity each year at a price that will not fluctuate because the source of energy is free. When gas is cheap, the cost of electricity from these plants may be expensive but it will not change when the price of gas soars. As an investment they offer a lower yield but that yield can be relied upon whatever the market conditions.

Risk associated with fuel volatility represents one aspect in which the electricity market that can be compared to the financial markets. However there is also another, speculation. This appears in at least two forms. Today there is increasing evidence that electricity markets are cyclical in the same way as financial markets. When electricity costs fall it becomes difficult for generating companies to make money; when they rise it is much easier. Therefore power generation companies are likely to time their investments so that the introduction of new capacity coincides with a period of high electricity costs. Opportunists are likely to try to take advantage of such swings too.

This is one form of speculation but it can take a more sinister form; market manipulation. The most dramatic event in a liberalized electricity market so far recorded took place in California in 2000 and 2001 when the equivalent of a stock market crash, a steep rise in the cost of electricity, took place. While this had many causes, several analyses have suggested that one of those causes was a form of market fixing in which strategies to limit the amount of power available on the market at particular times led in part at least to high prices[16]. Regulation ought to prevent such practices but as with financial markets, regulation often lags behind the market.

Risks of any type require some means of management. The response to the main risks found in the electricity market generally takes the form of financial instruments. These include hedging mechanisms such a forward contracts or futures which can be used to replace long term contracts that were common in the pre-liberalized market. Portfolio planning tools can also be used to find the best mix of generating types to create a stable generating fleet. Meanwhile economic modeling of power generation can incorporate some elements that attempt to take account of the major source of electricity price risk, fuel volatility. These issues will form the subject of this chapter.

Fuel prices and fuel price volatility

Global fuel prices, particularly for oil and gas, have become extremely volatile over the past 5-10 years. Some of this volatility is a consequence of global politics. Wars and uncertainty in the Middle East and reducing levels of supply in other parts of the world have both helped push up the price of oil. Gas prices are linked to oil prices on many markets across the world and so rising oil prices pull up gas prices too. In addition, security concerns in Europe where a large part of the gas supply is now imported, have added to regional strain and uncertainty. The global economic crisis of 2008-2009 suppressed prices for both oil and gas but they are rising again in spite of apparent supply surpluses.

The recent exploitation of gas reserves in shale deposits may help stabilize gas prices by offering vast new reserves of natural gas that were previously considered uneconomic to extract. In the US both reserves and output, which were falling, are now rising again and natural gas imports are expected to drop. The technology is being tried in Europe too and may help reduce reliance on imports. However there are environmental concerns that could limit its use and for the moment the outlook is uncertain.

Fluctuations and uncertainty are one feature of fuel markets today. The other is a steady rise in average prices. Again the oil and gas markets have shown the strongest effect though coal prices are rising too. What is worrying is that there is no compelling economic evidence to suggest that prices will fall again, at least not in the near future. (Even with the new US natural gas production, gas is trading at a benchmark of around $200/10^7kcalories - see tables below.)

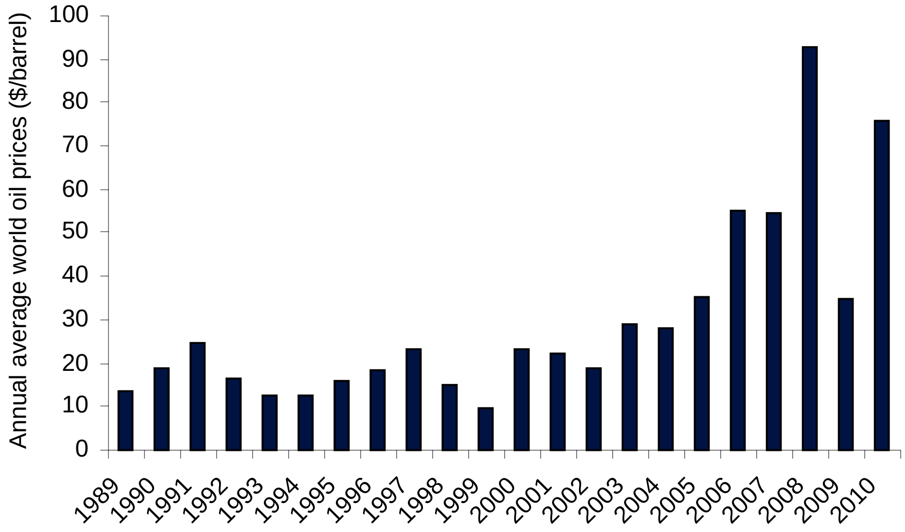
Table 3.7 shows average world oil prices between 1989 and 2010. As the table shows, prices during the 1990s varied between around $12/barrel and $25/barrel with peaks around 1990-1991 during the first Iraq war and again in 1996-1997. During the last decade, however, prices have been significantly higher with the average price exceeding $20/barrel in every year but 2002. In 2008 at the height of the commodities boom the average price was close to $93/barrel with spot prices rising much higher than this. Average prices slipped back to around $35/barrel in 2009 but were rising steeply again in the beginning of 2010 when the average price was already $76/barrel. On this evidence, prices appear set to continue upwards.

Table 3.7: Annual average world oil prices ($/barrel), 2010

Year	Cost ($/barrel)
1989	13.58
1990	18.91
1991	24.72
1992	16.22
1993	12.64
1994	12.37
1995	16.13
1996	18.41
1997	23.18
1998	15.21
1999	9.76
2000	23.17
2001	22.10
2002	18.68
2003	29.03
2004	28.00
2005	35.16
2006	55.12
2007	54.63
2008	92.93
2009	34.57
2010	75.77

Source: EIA[17] Business Insights Ltd

Figure 3.6: Annual average world oil prices ($/barrel), 2010



Source: EIA

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Table 3.8 shows a selection of average annual coal prices. The market for coal is not global in the same way as that for oil because of the cost of transport. As a result of this, coal is frequently consumed close to its source and so there are significant regional cost variations. The table shows prices in three regions, northwest Europe, the US and Japan. Coal in northwestern Europe is supplied from a mixture of indigenous sources and some imports. US coal is supplied primarily from indigenous reserves, while Japan has no significant coal reserves and all of its coal is imported. Even so, as the table shows, there is no consistent pattern to prices so that Japanese imported coal can cost less than US or European coal in some years.

The price of coal is generally less volatile than that of oil. During the 1990s the cost of a tonne of coal in northwest Europe varied between $29 and $44. In the US, the price was $29-$32/tonne and the cost of Japanese imported coal was $36-$51/tonne. These prices persisted until 2003, but after that the prices started to rise significantly in all three regions so that by 2007 it ranged from $87/tonne in northwestern Europe to $51/tonne in the US. In 2008 even coal prices rose dramatically, reaching close to $150/tonne in Europe but they fell back again in 2009 with the global recession, dropping to $55-$60/tonne. Average prices for the US and Japan in 2009 are not available.

Table 3.8: Annual coal prices ($/tonne), 2009

	Northwest Europe	US	Japan (imported steam coal)
1990	43.48	31.59	50.81
1991	42.80	29.01	50.30
1992	38.53	28.53	48.45
1993	33.68	29.85	45.71
1994	37.18	31.72	43.66
1995	44.40	27.01	47.58
1996	41.25	29.86	49.54
1997	38.92	29.76	45.53
1998	32.00	31.00	40.41
1999	28.79	31.29	35.74
2000	35.99	29.90	34.58
2001	39.29	49.74	37.96
2002	31.65	32.95	36.90
2003	42.52	38.48	34.74
2004	71.90	64.33	51.34
2005	61.07	70.14	62.91
2006	63.67	62.98	63.04
2007	86.60	51.12	69.86
2008	149.78	116.14	122.81
2009	*55-60*		

Source: BP[18], Commodity Online

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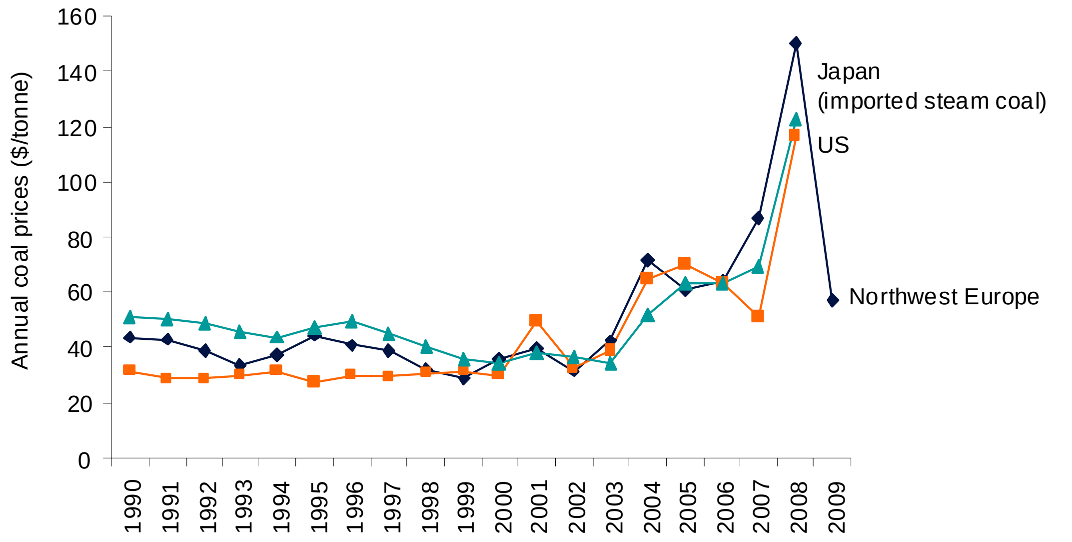
Figure 3.7: Annual coal prices ($/tonne), 2009



Source: BP, Commodity Online

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Table 3.9 shows prices for coal specifically for the power generation market. Steam coal for this market is generally based on contracts that allow for a lower price that the average market prices shown in Table 3.8. In 2008, for example, when the average price of US coal was $116/tonne, the cost of power generation steam coal was $47/tonne. Coal for power generation has traditionally been cheaper in the US than in other markets, as Table 3.9 shows. UK prices in 2007 were on average more than twice the US cost. In fact UK prices are the highest in the table during the last decade, even though the country has its own major coal reserves. Taiwan, in contrast, must import all its steam coal but even here prices are lower than in the UK.

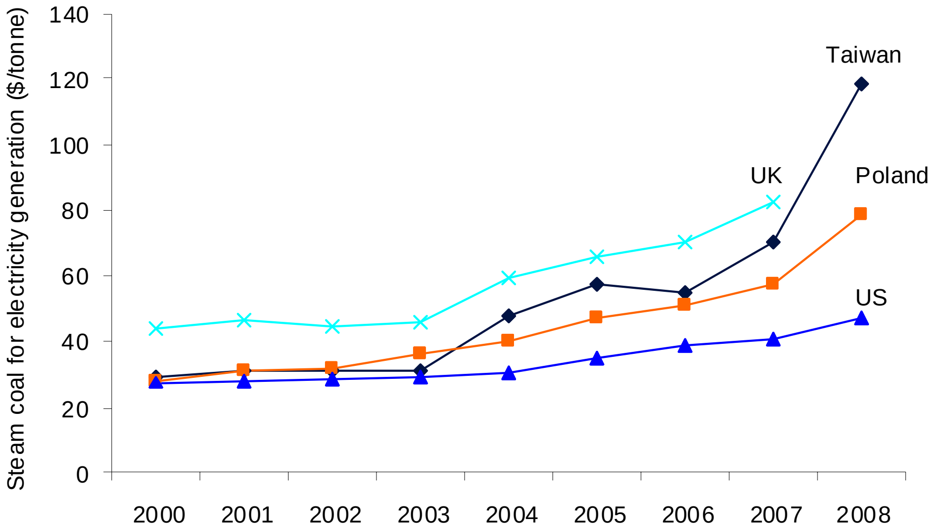
Table 3.9 does not include prices for 2009 but these will have generally fallen in line with the fall shown in Table 3.8. Even so, coal prices appear to be as much as 33% higher in 2009 than they were at the beginning of the decade.

Table 3.9: Steam coal for electricity generation ($/tonne), 2008

	Taiwan	Poland	US	UK
2000	29.67	28.2	27.5	44.4
2001	31.29	31.4	28.2	46.5
2002	31.43	32.2	28.7	44.5
2003	31.18	36.2	29.1	45.9
2004	47.75	40.0	30.9	59.7
2005	57.70	47.5	35.3	65.6
2006	54.68	51.4	38.8	70.1
2007	70.17	57.7	40.6	82.3
2008	118.49	78.9	47.0	-

Source: EIA Business Insights Ltd

Figure 3.8: Steam coal for electricity generation ($/tonne), 2008



Source: EIA Business Insights Ltd

Although the natural gas market is, like that for coal, regional rather than global, natural gas prices tend to follow oil prices. This is partly because the cost of oil represents an upper limit on the cost of gas. Companies that burn gas when it is cheap can often switch to oil if gas becomes more expensive and this prevents the price rising higher. That does not explain why gas prices should necessarily rise when oil prices do.

However, many gas contracts are written with prices linked to the price of oil and the strong link, which is historically based, looks unlikely to be broken in the near future.

Annual average gas prices in four regions, Japan, Europe, UK and the US are shown in Table 3.10. Japan has no gas reserves and the prices in the table are for shipped LNG. Prices in Europe, the UK and the US are for pipeline natural gas with a contribution from LNG. The series of prices in Table 3.10 all show a similar trend; prices were relatively high in the middle of the 1990s but fell towards the end of the decade then began to rise again, and eventually showing the dramatic increase in 2008 that is mirrored in oil and coal prices.

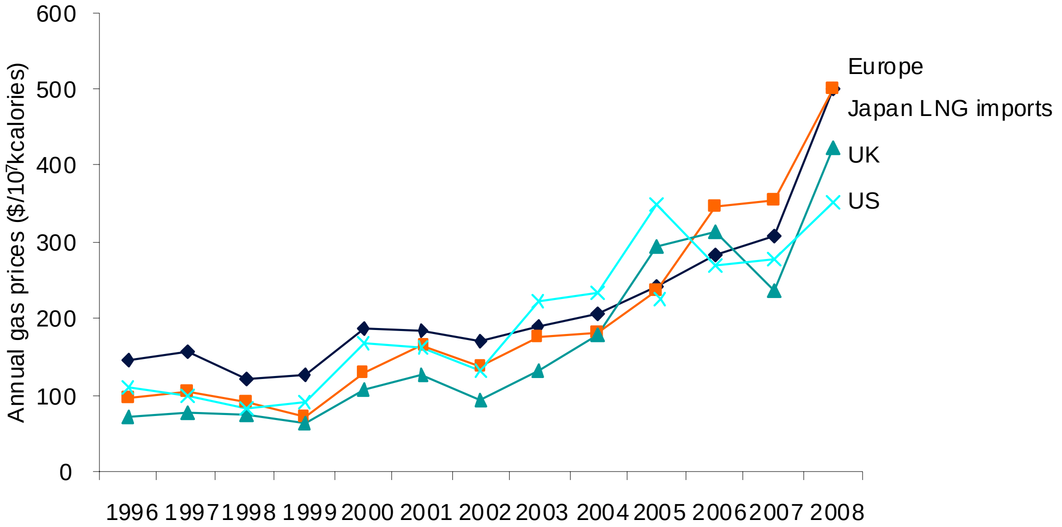
There are differences between the sets. The UK had the lowest prices during the mid 1990s when its gas came from North Sea reserves but those reserves were coming to the end of their lives and by the middle of the next decade the prices were relatively much higher. European prices were relatively low in the middle of the 1990s too but have risen during the present decade. Prices in the US are now the lowest of those in Table 3.10 while European prices are as high, if not higher, than the prices of LNG imported into Japan.

Table 3.10: Annual gas prices ($\$/10^7$kcalories), 2009

	Japan LNG imports	Europe	UK	US
1996	145	96	72	109
1997	155	105	78	100
1998	121	90	74	83
1999	125	71	63	90
2000	187	129	108	168
2001	184	165	126	162
2002	170	137	94	132
2003	189	175	132	223
2004	206	181	177	232
2005	240	236	293	349
2006	283	345	312	268
2007	307	354	235	276
2008	498	500	423	351

Source: BP[19] Business Insights Ltd

Figure 3.9: Annual gas prices ($\$/10^7$kcalories), 2009



Source: BP Business Insights Ltd

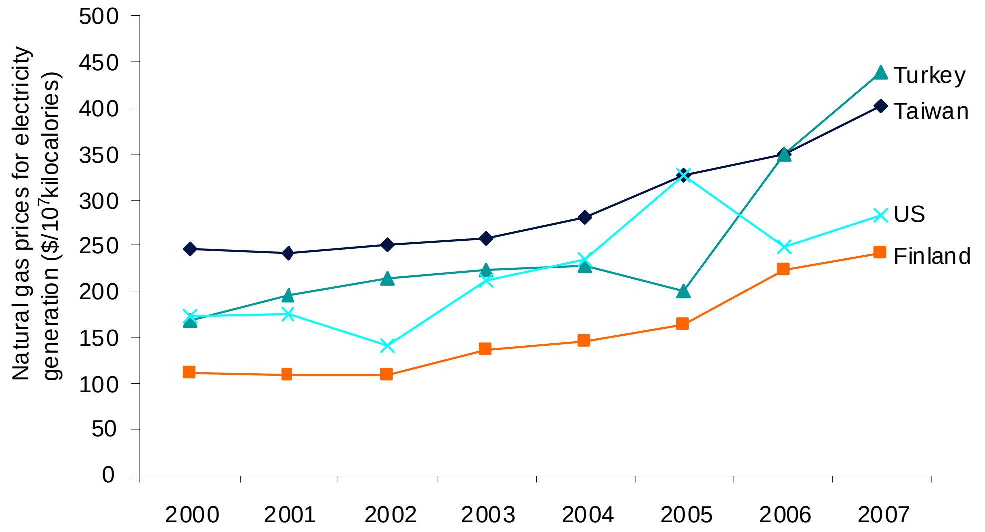
Table 3.11 shows prices paid for natural gas for electricity generation. Unlike the cost of coal for power generation, much natural gas is bought at spot market prices or using futures. As a consequence the costs are no lower than average prices, as can be seen by comparing the prices for gas in the US in Table 3.10 with those in Table 3.11. The latter table includes gas prices in Taiwan, Finland and Turkey as well as the US. Taiwanese prices have generally been the highest during the period covered by the table, 2000 - 2007 but prices in Turkey have also risen sharply during 2006 and 2007. Meanwhile the lowest prices are those in Finland.

Table 3.11: Natural gas prices for electricity generation ($/10^7 kilocalories), 2008

	Taiwan	Finland	Turkey	US
2000	246	113	169	173
2001	243	109	197	176
2002	252	109	214	141
2003	259	136	223	213
2004	281	146	228	236
2005	326	165	201	326
2006	349	223	349	248
2007	401	241	439	282

Source: EIA Business Insights Ltd

Figure 3.10: Natural gas prices for electricity generation ($/10^7 kilocalories), 2008



Source: EIA Business Insights Ltd

Finally, Table 3.12 shows prices a more extensive set of natural gas prices for power generation in the US. These are in $/thousand cubic meters and so cannot be compared directly with those in the previous tables. These figures show clearly how volatile prices have been in the past decade, with spikes in 2001, 2005 and 2008. Prices dropped back sharply in 2009 but are still above the level at the beginning of the decade.

As noted above, gas from shale deposits in the US is having a dramatic effect on supply so that in 2010 the country has overtaken Russia and the world's biggest producer of natural gas for the first time in close to a decade. Even so, the benchmark price of gas at the beginning of 2010 was still around $\$200/10^7$kcalories, significantly higher than at the beginning of the decade (see Table 3.11).

Table 3.12: US natural gas prices for electricity generation ($/thousand cubic meters), 2009

	Price ($/thousand cubic meters)
1997	98.2
1998	84.8
1999	92.5
2000	154.7
2001	162.8
2002	130.0
2003	196.7
2004	215.8
2005	299.1
2006	251.1
2007	258.1
2008	328.0
2009	155 - 233

Source: EIA

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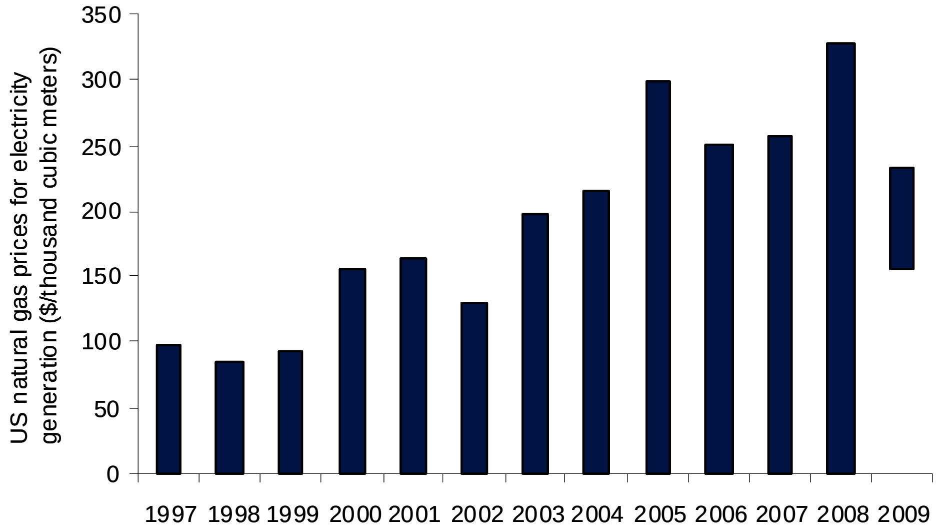
Figure 3.11:US natural gas prices for electricity generation ($/thousand cubic meters), 2009



Source: EIA

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A steady increase in the price of fossil fuel increases the cost of electricity generated from power plants burning coal, oil and gas. A steady price increase can be accommodated by economic models and need not be overly detrimental to economic activity. However fuel prices volatility, when it leads to sharp rises in the cost of fuel as seen in 2007 and 2008, can have a harmful effect on economic activity. Accommodating this type of volatility in an economic model is more difficult too.

Fuel price risk and risk modeling

Fuel prices risk is a particularly pertinent issue in today's power generation market because of the prevalent use of natural gas for electricity generation. The latter is a relatively clean fuel that produces less CO_2 per unit of electricity than coal. In addition gas turbine combined cycle power plants are extremely cheap to build and this makes them an attractive investment for private sector power generation companies. The obverse of this is that the cost of electricity from a natural gas power plant depends to a large extent on the cost of gas. When this is low, the electricity is cheap. But when gas prices rise, electricity prices can rise damagingly high too. Evidence for this can be seen in liberalized electricity markets in the US and particularly in the UK where a predominance of gas-fired power stations built following sector liberalization led directly to high electricity prices in 2007 and 2008.

This problem is built into the liberalized market structure and is one of the pieces of evidence suggesting that the structure does not necessarily meet national needs. However, it is compounded by the fact that the levelized cost of electricity model discussed in Chapter 2 does not take any account of fuel volatility. This lead to a bias in favor of natural-gas fired power generation and away from capital intensive investments, particularly renewable but also nuclear generation.

If there was a way of building volatility into the economic modeling tools used for assessing project viability then it might at least be possible to provide a more realistic measure of expectation when comparing technologies. This is what the Capital Asset Pricing Model (CAPM), a model taken from the financial sector, attempts to achieve[20]. The key feature of this model is that it takes account of the different risks associated with different payment streams for a power plant when calculating the 'present value' for levelized electricity cost purposes. The three key streams for a natural gas fired plant are the loan repayments, operation and maintenance costs and fuel costs. Loan repayments are generally fixed payments and therefore represent a predictable, very low risk. Operation and maintenance costs are similarly relatively stable and the risk associated with them is low too.

Using the levelized cost model, these two payment streams may be added together and a similar discount rate applied to them. However the cost of fuel, as we have seen above, represents a high risk since prices can change abruptly and unpredictably. Therefore according to the CAPM a different discount rate should be applied, reflecting this different level of risk.

In the case of a levelized cost model a high discount rate implicitly predicts that 'present value' will fall significantly the further into the future one moves (see Figure 5.23 in Chapter 2). But in recent years the price of gas has not fallen. In fact in real terms the price has in some cases tended to rise. This suggests that a low, or even negative discount rate should be applied to natural gas costs when calculating the present value. The effect of this is to increase the levelized cost of electricity from a gas-fired power station significantly. Figures from 2003 show that using a realistic discount rate for natural gas prices increased the levelized cost of gas from $20/MWh to $38/MWh, virtually doubling it[21]. The level of risk has, if anything, risen since then. There is no evidence that the CAPM model is being used widely but if it were it would offer a much more realistic levelized cost estimate than the one based on a single discount rate for each payment stream.

One way to judge the significance of fuel price risk is to compare the levelized cost of gas with the cost of futures for gas covering a similar period to the levelized cost calculation. This exercise has been carried out in recent years by researchers at the Ernest Orlando Lawrence Berkeley National Laboratory in the US. The basis for this exercise is the publication of the US EIA Annual Energy Outlook (AEO), which includes a levelized cost calculation to predict the future price of natural gas. The researchers compare this figure with the actual cost of buying gas futures in order to lock in the price of gas for up to ten years ahead.

Over the past decade the levelized cost prediction from the AEO has generally been lower than the cost of gas futures, suggesting that natural gas will cost more than the EIA prediction would suggest. In 2008 for example, gas futures cost $2.34/10^{7}kcals more than the levelized cost predicts. This premium translates into an increase in the cost of generation from an advanced gas turbine combined cycle power plant of around $4/MWh. The average premium over the preceding three years was $6/MWh.

The latest memo on the subject[22] finds that the premium of the futures over the AEO prediction is only $0.44/10^{7}kcals. This is similar to the 2009 analysis and significantly better than the average over the previous years of the decade. However the authors caution that analysts should look at a wider range of cost predictions since there is no clear basis for concluding that this coincidence between futures and the predicted price will continue.

Electricity price spikes

Fossil fuel prices are essentially unpredictable since they depend on both supply and demand and a range of other factors including the global political situation and the extent of fuel speculation. Fuel price rises need not, on their own, lead to large rises in the cost of electricity. That will depend on the generation mix in a particular country or region and may also be influenced by regulation of electricity prices. However liberalized electricity markets do appear to be vulnerable to the same type of catastrophic events as financial markets and a significant cause are fuel prices.

The UK saw a major electricity price spike at the end of the first decade of the century. This was primarily a result of generators building gas-fired combined cycle power plants over the previous fifteen to twenty years which came to form the major source of power. As a consequence when gas prices rose, electricity prices had to follow. The UK problem was compounded by the fact that the UK had been self-sufficient in natural gas and prices had been consistently low. However once reserves dwindled and gas had to be imported, prices became linked to those in continental Europe which had traditionally been much higher since they are linked to oil prices.

The price spike in the UK can be traced to a relatively simple series of events. Much more troubling was the spike in California that occurred in 2000 and 2001. This took place soon after an open electricity market was established in the state, in April 1998. The average cost of electricity in June 2000 was $143/MWh, more than twice as high as during any other month since deregulation. Table 3.13 traces the cost of electricity through 2001 based on prices at the Intercontinental Exchange. As the figures show, prices were extremely volatile during the first half of the year, reaching $485/MWh in February. However, prices fell in June and by the end of the year electricity was trading at $30/MWh, 16 times cheaper than the February peak.

Table 3.13: Spot prices for electricity in California ($/MWh), 2001

Date	Average price ($/MWh)
08-Jan	152
16-Jan	230
01-Feb	185
14-Feb	485
28-Feb	260
15-Mar	202
30-Mar	225
11-Apr	180
30-Apr	270
14-May	210
01-Jun	166
15-Jun	63
02-Jul	91
16-Jul	43
01-Aug	49
15-Aug	44
31-Aug	30
14-Sep	30
01-Oct	28
15-Oct	26
01-Nov	33
15-Nov	20
30-Nov	31
14-Dec	32
28-Dec	28

Source: US Intercontinental Exchange[23]

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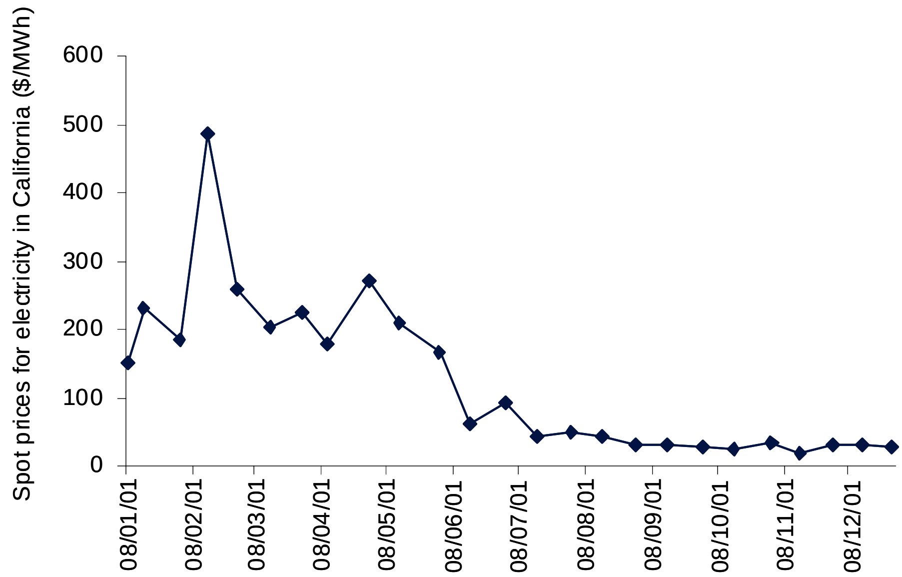
Figure 3.12: Spot prices for electricity in California ($/MWh), 2001



Source: US Intercontinental Exchange

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The causes of this price spike were many. A dry summer in 2000 reduced hydropower output while increasing daytime air conditioning demand. Electricity suppliers were buying most of the power beyond that which they produced themselves on the daily market at daily market prices. And much of the power generation output was based on gas-fired plants which were vulnerable to gas price volatility. As Table 3.10 shows, gas prices in the US in 2000 and 2001 were much higher than in 1999.

The effect of the high electricity prices was to provide independent generating companies with an unexpected windfall while at the same time causing massive problems for regulated utilities which had buy power from the wholesalers and sell it at a lower price to consumers. In 2001 the state of California had to take over wholesale purchases of power and one of the major utilities, Pacific Gas and Electric declared itself bankrupt[24].

The structure of the liberalized market may have had its effect too, by allowing electricity wholesalers too much power. When supplies are constricted, the marginal price of electricity rises and recognition of this may have led some wholesale electricity suppliers to manipulate the market. The problem is that with such a complex array of causes and effects, operation of such a market is difficult to predict. As with financial markets, changes in market structure together with regulatory changes may help prevent a repeat of this situation. Unfortunately as the recent global financial crisis has made clear it cannot prevent the situation that has not yet been foreseen.

Risk hedging

There are ways for consumers and companies to defend themselves against the various risks presented by electricity markets. Some retail electricity companies now offer their customers long term price stability contracts, at a premium. Companies purchasing electricity on the market can, equally, hedge against price volatility by purchasing forward contracts or electricity futures which guarantee the delivery of a specified quantity of electricity at a specified date and time in the future for a specified price. Generators can use similar fuel derivatives to ensure long term fuel supply at a stable price. Financial instruments of this type are effectively a replacement for long term contracts that were common in pre-liberalization world of the electricity industry.

These are simple hedging mechanisms but there are much more complicated mechanisms, too, such as spark-spread options which link the price of electricity to the price of the fuel needed to generate it. These and other options and forwards are being used with increasing frequency as techniques from finance markets become ever more common in the electricity market. Such techniques are a protection against price volatility. There are also ways of attempting to minimize the effects of price volatility at the capacity planning stage by incorporating risk into levelized cost calculations as outlined above and by using portfolio planning, another technique borrowed from financial markets.

Portfolio planning theory

Portfolio planning theory is a technique used in the finance industry to determine the optimum mix of investments in a financial portfolio in order to achieve the best return on investment over time[25]. This mixture will include some investments that are very risky but offer a high rate of return and some that are of low risk but equally offer a low rate of return. By combining them judiciously, it is possible to find a mix that will maximize the rate of return and minimize the risk.

In the finance market, government bonds are considered to be riskless (though as the recent financial crisis has shown, they do in fact carry a risk). As a consequence they tend to be expensive and do not provide large returns on an investment. Other investments carry a higher level of risk, but by the same margin tend to be cheaper and potentially offer a higher rate of return. Government bonds are 'safe' investments to which investors resort when market conditions are bad. In normal times, however, the investor who wants to make good returns will want to invest in riskier stocks.

There is a direct analogy between a portfolio of financial stocks and a portfolio of electricity generating plants. Each type of generating plant offers a different return on investment but equally each also carries a different level of risk. And while the analogy between modular power generating units and much more divisible stocks is not perfect, the match appears to be close enough to make it worthwhile to explore the application of planning techniques from one to the other.

In finance, the measure of success of a portfolio of stocks is the rate of return. If this is transferred to energy planning, the analogous concept to return on investment is kWh/$ (yield) i.e. the number of kWh achieved for each unit of investment. This is the inverse of the levelized cost. The higher the latter, the lower the value of kWh/$[26] [27] .

Portfolio planning is generally used to determine the optimum mix of two or more risky stocks with the possible addition of some riskless stock. There is no point in using it to plan investment in riskless stocks alone since the best return (assuming no risky stocks are involved too) is obviously from the riskless stock that pays most interest. By using statistical techniques based on the historical level of risk associated with each risky stock and its rate of return, the technique seeks to calculate the risk and return associated with each possible combination of risky stocks in order to find which combination will be most fruitful.

In order to make this calculation it is necessary to know the rate of return of each individual stock and also to put a figure on the risk associated with it. The calculation of this risk is based on the historical variance in the value of a stock, measured statistically. It is also necessary to know the level of correlation between the value of each pair of stocks involved. That this is important becomes clear if we assume that two stocks are 100% correlated. Then if the value of one moves down, the other will fall too so there is no point in mixing them. However if the correlation between the two is very low, then statistics predict that the movement of one will probably be at least partly cancelled by an opposite movement in the second.

When an analysis is carried out on a mixture of two risky stocks, the results can be plotted on a curve that shows return as a function of risk. Starting with a portfolio comprising 100% of a high return, high risk stock, as the proportion of a lower risk, lower return stock is increased so both the level of risk and the level of return of the portfolio falls. However, if the two are not completely correlated, then there comes an inflection point at which the risk stops falling, and begins to rise again. In the extreme case where the two stocks are completely uncorrelated, this point of inflection represents a portfolio of the two which is completely riskless. More normally however, it is the point of lowest risk.

One of the most interesting results of this analysis comes when a proportion of riskless assets are added to an existing portfolio of risky assets. The effect, depending upon the mix in the original portfolio, is to create a portfolio that has lower risk for a similar rate of return. In other words riskless assets, even though they offer a lower rate of return alone, can be used to reduce risk without reducing the rate of return.

The significance of this to energy planning is profound. In electricity generation there are a range of risky investments. These are those generating assets that rely on fossil fuels to generate electricity since they are exposed to the risk of fuel price fluctuations in the same way that the value of risky shares fluctuate on the stock market[28]. It is possible to use portfolio planning to find the most judicious combination of say coal and gas-fired power generating capacity to optimize both risk and return (high yield or low cost of energy). In this case, as in the case of stocks, the risk associated with fuel prices fluctuations is calculated on the basis of historical prices. The correlation between the prices is also important since, as we have seen above, the cost of gas and oil tend to be closely linked, whereas that of gas and coal are less dependent on one-another.

Once on optimum mix has been determined, then the effect of adding riskless assets can be examined. In this case, as already noted above, riskless assets are renewables such as wind or hydro which have no exposure to fuel risk. There are other risks, such as construction risk, to which they are exposed, but analysis indicates that the results are not very sensitive to these risks whereas they are extremely sensitive to fuel risk.

What the results of a full analysis suggest is that adding a proportion of renewable capacity has the effect of either reducing cost (increasing yield) or reducing risk compared to the generating portfolio comprising gas and coal-fired capacity alone. While the actual figures obtained are extremely situation-specific, the conclusion is that the addition of renewables to portfolio of fossil fuel (or fossil fuel and nuclear) based generating plants will have the long term effect of either reducing the cost of electricity or reducing the risk of significant price fluctuations.

While this outcome may appear unexpected, it should not be. The result is equivalent to saying that including some renewable capacity offers a hedge against volatility. Renewable technologies provide a predictable (if not entirely reliable over the short term) source of electricity and while this may cost more than the electricity generated by gas-fired combined cycle power plants when gas prices are low, if gas prices rise then the renewable capacity provides a cap beyond which costs should not rise.

Of course, this is an oversimplification and costs will depend on the absolute level of demand, but the economic significance of the effect should not be underestimated. There is clear evidence that volatile fuel prices can have a significant effect on economic prosperity. Renewable generating technologies, by providing a hedge against this volatility, help maintain economic output in spite of fuel price rises.

Portfolio planning theory therefore appears to offer an important means of planning both capacity additions and capacity mix at a national and international level. How the results of such an analysis are to be applied in a liberalized market is less clear. The best national mix of generating plants may require individual power generating companies to build power plants that they do not see as their best investment choice. If national or regional planning of this type becomes politically attractive once more then some major changes to the way electricity markets are controlled will be necessary.

Chapter 4

Historical costs of electricity, capital cost and the technology learning effect

Chapter 4 Historical costs of electricity, capital cost and the technology learning effect

Introduction

The two previous chapters have been concerned with economic modeling of the electricity market in order to predict the cost of electricity. This in turn allows decisions to be made about the best type of generating capacity to build in order to provide the cheapest or the most reliable electricity supply in the future.

While future costs might be what businesses and policy-makers want, these predictions are always speculative. Historical electricity prices, on the other hand, are known. Past prices cannot be used to determine future prices but they do form a yardstick by which to judge predictions and they do provide a historical memory upon which predictions might be based. As we saw in Chapter 3, portfolio planning theory depends on knowing the correlation between the cost of electricity from different sources. This can only be obtained from a comparison of historical prices.

This chapter will take a brief look at historical electricity prices in order to highlight some of the salient trends. It will also examine another historical trend, the technology learning curve that leads to a lowering in the cost of a technology as experience and volumes of production increase. This affects the capital cost of many technologies and can be a useful guide when examining the potential of new technologies.

Historical costs of electricity

As noted above, the historical cost of electricity is the benchmark against which any predictions of future cost must be compared in order to form an opinion about whether the estimated costs are reasonable and valid. Historical figures can also provide some insight into the factors affecting electricity prices. Of course the history of electricity prices cannot tell us what is going to happen in the future. But by comparing the past behavior of prices with that of the various factors we believe affect electricity costs, we may at least be able to draw some conclusions about how significant these factors are.

Tables 4.14 and 4.15 present figures for the historical cost of electricity for industrial (Table 4.14) and domestic (Table 4.15) use in seven countries around the globe. These figures are averages and in most cases will represent the cost across a portfolio of different generating technologies. They are not the cost of generation figures that have been considered in Chapters 2 and 3 but retail prices so they include both profit margins and the effects of any subsidies. Nevertheless the trends they exhibit are likely to be broadly similar to the shifts experienced in wholesale prices.

The first thing to note is that the prices in the two tables are generally significantly different. This is normal; industrial prices are for much larger volumes of electricity and have historically tended to be lower than domestic prices. The size of the difference varies from country to country, as the table shows. In France in 2006 the domestic price was 2.8 times the industrial price. In Kazakhstan the difference was a factor of 1.5 and in the Czech Republic a factor of 1.3. Occasionally the industrial cost is higher than the domestic cost as in Mexico in 2007. There is generally a sign of cross-subsidy where industrial consumers are being charged more in order to keep the price down for domestic consumers. In some cases this is justified by social conditions. Often it is simply a result of political convenience.

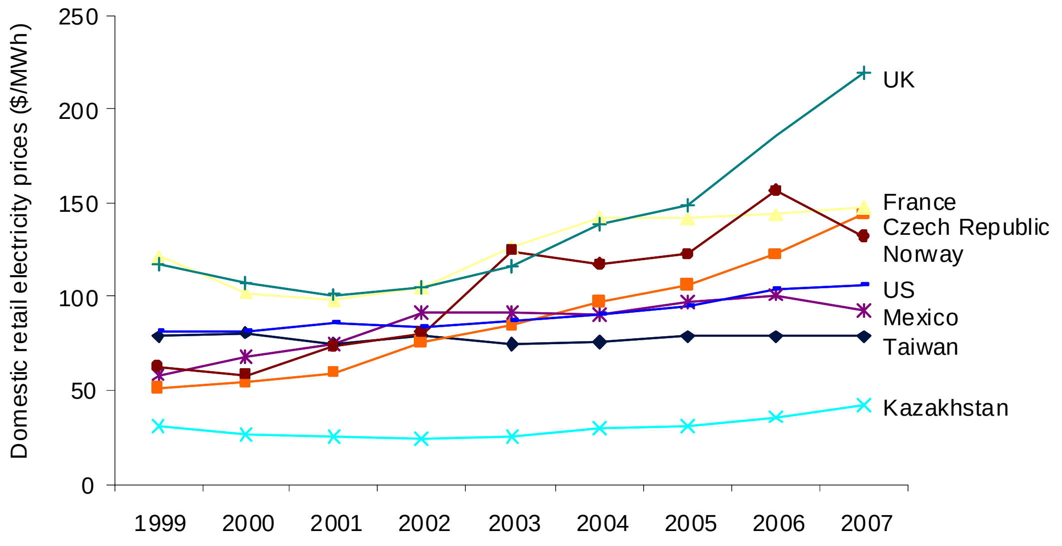
Industrial prices, as well as being lower, are likely to be a better guide to wholesale price trends than are domestic prices, which can be subject to range of additional commercial factors. The spread in industrial prices in Table 4.15 was 355% in 1999 when Kazakhstan is included; when it is excluded and electricity costs in this country appear to be heavily subsidized, the spread is 152%. In 2007 the spread was 240% (excluding Kazakhstan). The spread within domestic prices in 1999 in Table 4.14 was 237% excluding Kazakhstan and 390% including it. In 2007 the domestic price spread was 277%.

Table 4.14: Domestic retail electricity prices ($/MWh), 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007
Taiwan	79	81	75	79	74	76	79	79	79
Czech Republic	51	54	60	76	85	97	106	122	144
France	121	102	98	105	127	142	142	144	148
Kazakhstan	31	27	26	25	26	30	31	36	43
Mexico	59	68	75	92	91	90	97	101	93
Norway	63	58	73	81	124	117	122	156	132
UK	117	107	101	105	116	138	149	186	219
US	82	82	86	84	87	90	95	104	106

Source: EIA Business Insights Ltd

Figure 4.13: Domestic retail electricity prices ($/MWh), 2007



Source: EIA Business Insights Ltd

Both absolute prices and the price variations between and within individual countries show enormous variety. Electricity prices, both domestic and industrial, in Taiwan changed relatively little between 1999 and 2007. The difference between the two is also almost constant at around $21/MWh in most years too. This suggests a heavily regulated market. Figures for France show a large difference between domestic and industrial prices, with the domestic prices often around 260%-270% higher than industrial prices. French domestic prices are among the highest in Table 4.14. In Table

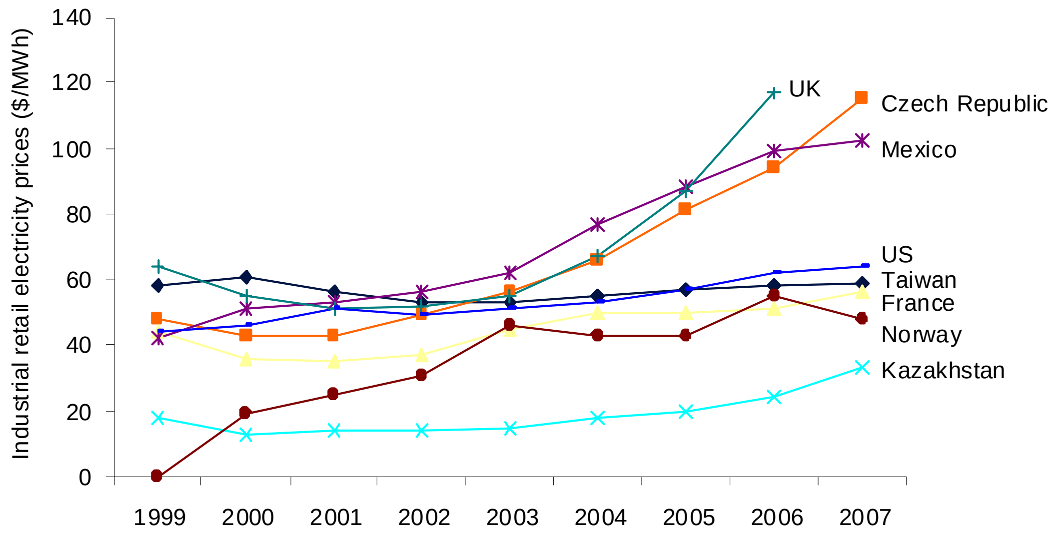
4.15, French industrial prices are close to the lowest. In principle the price of French electricity, derived in large part from its fleet of nuclear power plants, is expected to be low so the high domestic cost is likely to be a matter of policy rather than economics.

Table 4.15: Industrial retail electricity prices ($/MWh), 2007

	1999	2000	2001	2002	2003	2004	2005	2006	2007
Taiwan	58	61	56	53	53	55	57	58	59
Czech Republic	48	43	43	49	56	66	81	94	115
France	44	36	35	37	45	50	50	51	56
Kazakhstan	18	13	14	14	15	18	20	24	33
Mexico	42	51	53	56	62	77	88	99	102
Norway	-	19	25	31	46	43	43	55	48
UK	64	55	51	52	55	67	87	117	
US	44	46	51	49	51	53	57	62	64

Source: EIA Business Insights Ltd

Figure 4.14: Industrial retail electricity prices ($/MWh), 2007



Source: EIA Business Insights Ltd

Kazakhstan is typical of a country that subsidizes fuel and electricity prices. Both retail and domestic prices are significantly lower than in any other country in either table. However the industrial price trend suggests some attempt is being made to reign in subsidies. The extraordinarily high electricity prices in the UK which were discussed in Chapter 3 can also be seen in the figures in both tables.

Tables 4.14 and 4.15 show electricity prices fluctuating over the last decade, though with much less volatility than that observed in gas prices noted in Chapter 3. They also show, in most cases at least, that electricity prices have rise over the period between 1999 and 2007. The figures do not reflect the extraordinary financial situation in 2008 and 2009 which will have led to even greater volatility in most cases.

The figures presented in Tables 4.14 and 4.15 are for countries across the globe. Table 4.16, below, shows figures for a closely knit region, the European Union. The table presents both industrial and domestic electricity costs in each of the 27 countries in the first quarter of 2009 as collated by Eurostat.

Table 4.16: Retail electricity prices in EU, first quarter 2009, excluding taxes (€/MWh)

	Industrial (€/MWh)	Domestic (€/MWh)
Austria	-	138
Belgium	103	143
Bulgaria	64	69
Czech Republic	106	110
Cyprus	116	134
Denmark	74	124
Estonia	59	71
Finland	66	97
France	65	96
Germany	98	140
Greece	95	106
Hungary	122	128
Ireland	121	179
Italy	209*	144*
Latvia	90	96
Lithuania	92	80
Luxembourg	110	162
Malta	138	146
Netherlands	94	144
Poland	86	88
Portugal	87	126
Romania	81	81
Slovakia	142	129
Slovenia	106	107
Spain	110	129
Sweden	62	104
United Kingdom	108	140

* These figures include taxes

Source: Eurostat Business Insights Ltd

Even though the EU is attempting to harmonize its electricity market, the figures in Table 4.16 show that a wide variation in prices still exists. The lowest industrial price in the table, €59/MWh is found in Estonia. The highest, €142/MWh is in Slovakia. As for domestic prices, the lowest is found in Bulgaria, €69/MWh while the highest, €179/MWh is found in Ireland. (In both cases the figure for Italy is higher, but the figures in the table include tax which is excluded in all other cases. Even so it appears likely that prices in Italy are the highest in the EU.)

As with Tables 4.14 and 4.15, domestic prices are generally higher than industrial prices. Slovakia and Lithuania are exceptions while in Romania the two prices are identical. Even neighboring countries with power exchange links such as France, Germany and Belgium show widely diverse prices. In fact the prices within the EU show just as much diversity as the prices from across the globe shown in the previous two tables. And while it may be possible to draw some general conclusions from figures like those in these three tables, what they also show clearly is that in order to understand the price of electricity in any country it is necessary to examine the specific conditions that prevail in that country.

The prices in the tables above are all average prices but prices in liberalized markets can vary widely from place to place. In California in 2005 for example, actual retail costs of electricity ranged between $20.2/MWh for a federal utility - the Western Area Power Administration, WAPA - to $357/MWh for the investor-owned Mountain Utilities. (WAPA is a utility with exclusively hydro-based generation and the prices give an indication of how cheap hydro-generated electricity can be once capital costs of plants are paid off. Mountain Utilities supplies power exclusively to the Kirkwood resort from diesel plants.) It is unlikely that any new generator could ever challenge WAPA but as Mountain Utilities' price demonstrates, there can be a market even for extremely expensive power.

Retail cost and levelized cost

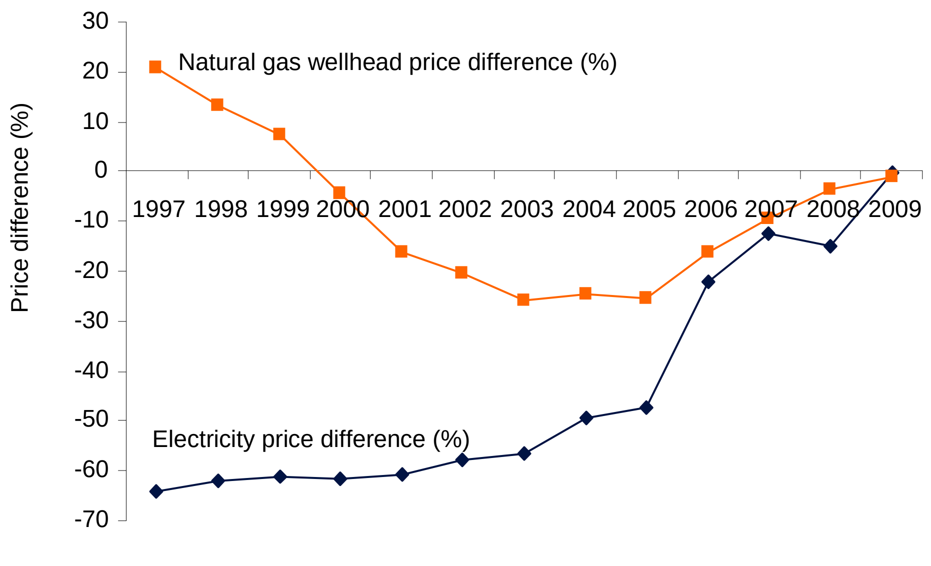
How does retail cost compared with levelized cost? The US EIA has, since 1996, compared the forward projections for a variety of parameters made in the reference scenario in the US Annual Energy Outlook with the actual value of those parameters[29]. Some of these figures are shown in Table 4.17. The figures in the table show the percentage difference between the actual price of natural gas (wellhead price) and electricity in 2008 and the prices predicted for 2008 in the Annual Energy Outlooks of the previous thirteen years. (Note that each AEO is base on figures for the previous year, so AEO 2009 has figures for 2008 onwards.)

Table 4.17: Predicted prices for gas and electricity in 2008 from earlier US Annual Energy Outlooks (%), 2009

AEO year	Natural gas wellhead price difference (%)	Electricity price difference (%)
1997	-64.3	20.8
1998	-62	13
1999	-61.3	7.2
2000	-61.6	-4.3
2001	-60.7	-16.1
2002	-57.9	-20.3
2003	-56.6	-25.7
2004	-49.5	-24.5
2005	-47.5	-25.4
2006	-22.3	-16.4
2007	-12.4	-9.4
2008	-14.9	-3.6
2009	-0.2	-1.3

Source: US EIA Business Insights Ltd

Figure 4.15: Predicted prices for gas and electricity in 2008 from earlier US Annual Energy Outlooks (%), 2009



Source: US EIA Business Insights Ltd

The first column in the table shows the extent to which predicted gas prices differed from the actual price. The negative figures show where the predicted cost underestimated the real cost. In the case of gas the predicted cost from all the AEOs shown was lower than the actual cost and for a large part of the time this was by a significant margin. This underestimate of gas costs had a significant, though lower effect on electricity cost estimates. Again for most of the period the cost of electricity was underestimated by much less than the cost of gas though in the late 1990s the cost of electricity was actually overestimated.

These figures are for predictions for a single year in the future. Predictions for earlier years often show less obvious patterns. Nevertheless the figures highlight the dangers that can be attached to basing future planning entirely on levelized cost predictions.

Technology costs, the learning effect and economies of scale

As discussed above, an examination of national retail electricity price trends may provide some insight into the electricity market of the country or region in question, insight that can prove valuable when considering future investment. A similar exercise can be carried out in relation to the historical trends in the capital cost of power generation technologies. And this, similarly, can provide insight when considering the value and direction of future investment.

Price inflation, which affects materials and labor, tends to increase the cost of products including power stations over time. This has been particularly pronounced during the last four to five years as commodity prices have soared and the effects can be seen in the capital cost tables in Chapter.2. On the other hand experience with the construction of a particular type of power plant and refinements of the technology both tend to bring the price down.

The effect of technology development is particularly important. A completely new power generating technology tends to be expensive, is often relatively inefficient and frequently unreliable. However as it is refined and developed the cost normally comes down while the efficiency rises and reliability improves. These improvements generally lead to a fall in the unit cost per kW. This may not be very significant in the short term but over generations of a particular technology the effect can become extremely significant.

This fall in price is not normally uniform. In the early years of development of a particular technology the fall tends to be faster than in later years when the technology is approaching maturity. Eventually the curve levels out and prices start to rise as a consequence of inflation.

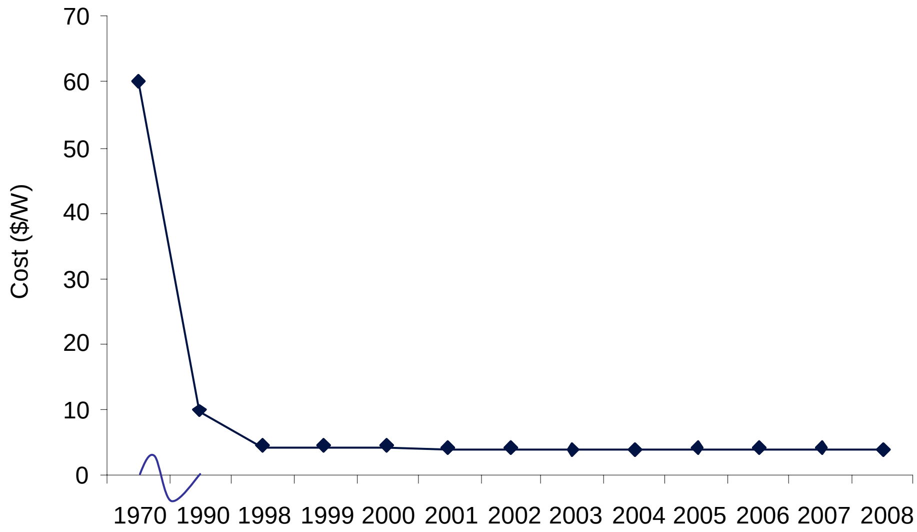
Table 4.18 shows how the cost of solar photovoltaic modules has changed over time. In 1970 the average cost of a unit with an output of one watt was $60. This had fallen to $10 by 1990 and in 2000 it reached $4.4/W. During the following decade the rate of change has leveled off so that by the end of the decade the price was hovering around $3.8/W - $4.1/W.

Table 4.18: Global solar photovoltaic module costs ($/W), 2008

	Cost ($/W)
1970	60.0
1990	10.0
1998	4.5
1999	4.5
2000	4.4
2001	4.2
2002	4.0
2003	3.8
2004	3.9
2005	4.1
2006	4.2
2007	4.1
2008	3.8

Source: Lawrence Berkeley National Laboratory[30], Business Insights[31] Business Insights Ltd

Figure 4.16: Global solar photovoltaic module costs ($/W), 2008



Source: Lawrence Berkeley National Laboratory, Business Insights   Business Insights Ltd

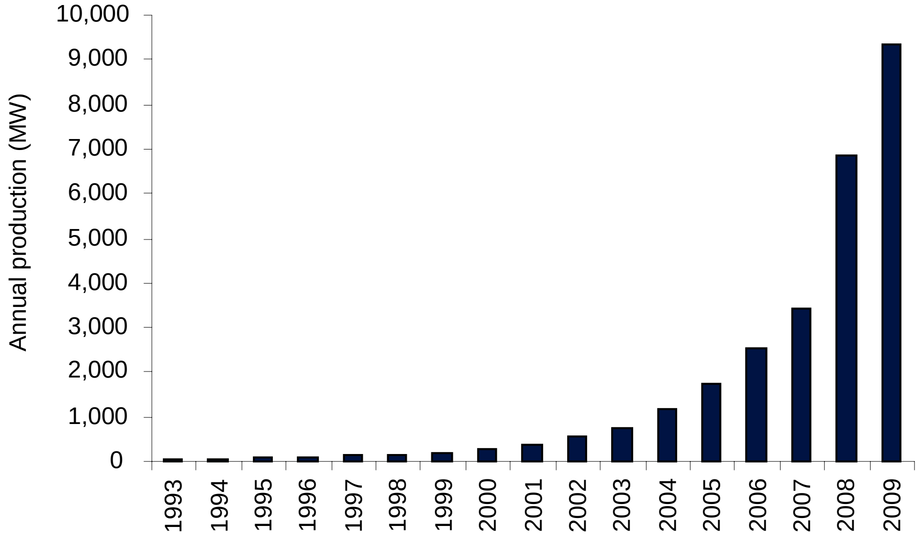
This is a typical 'learning curve' drop in price due to better technology but it also reflects economies of scale that can be achieved with mass production of solar cells, Global annual solar cell production volumes for the past decade and a half are shown in Table 4.6. Between 1993 and 2003, annual production increased from 60MW to 742MW, an increase of over twelve times. Between 2003 and 2009, production increased by nearly another thirteen times to reach 9,340MW. Such massive increases in production volumes allow units to be produced at significantly lower unit price. So while it might not be obvious from the figures in Table 4.18, the gains made by economies of scale and from technology improvement have enabled to price to remain stable even though many commodity and production prices have risen.

Table 4.19: Global solar cell production (MW), 2009

	Annual production (MW)
1993	60
1994	69
1995	78
1996	89
1997	126
1998	155
1999	200
2000	277
2001	386
2002	562
2003	742
2004	1,194
2005	1,727
2006	2,521
2007	3,440
2008	6,850
2009	9,340

Source: EurObserv'ER, Business Insights[32], SolarBuzz — Business Insights Ltd

Figure 4.17: Global solar cell production (MW), 2009



Source: EurObserv'ER, Business Insights, SolarBuzz — Business Insights Ltd

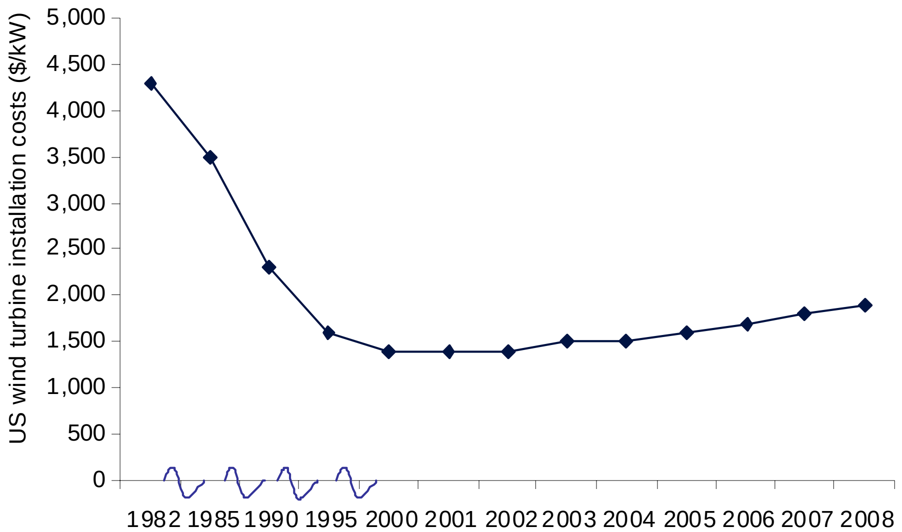
Solar photovoltaic power production remains expensive, even with the gains that have been made in recent years. A step change in costs may be achieved when new thin film technology becomes widely available but it may take a decade or more for this technology to become widely introduced. Wind power, however, is considered by many to be competitive today. Data for wind turbine costs and production volumes are shown in Tables 4.20 and 4.21.

Table 4.20: US wind turbine installation costs ($/kW), 2008 [33]

	Cost ($/kW)
1982	4,300
1985	3,500
1990	2,300
1995	1,600
2000	1,400
2001	1,400
2002	1,400
2003	1,500
2004	1,500
2005	1,600
2006	1,700
2007	1,800
2008	1,900

Source: US DOE[34] Business Insights Ltd

Figure 4.18: US wind turbine installation costs ($/kW), 2008



Source: US DOE Business Insights Ltd

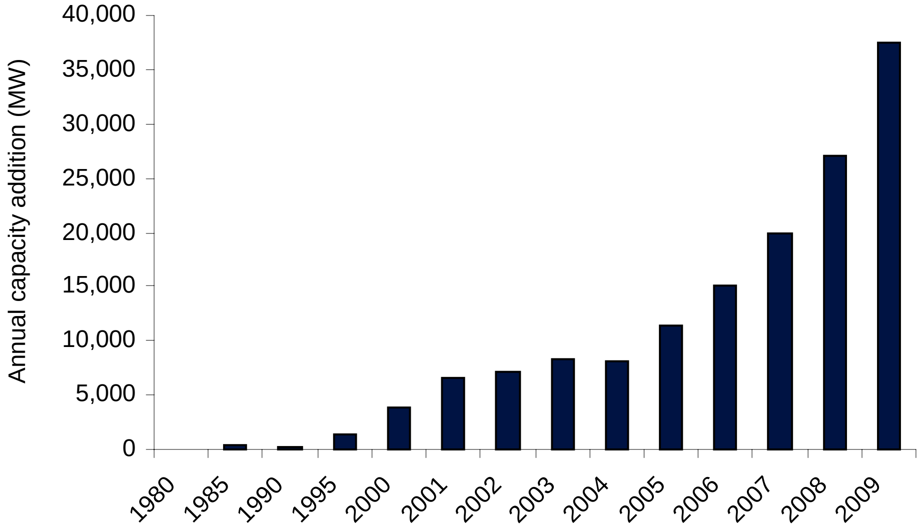
Table 4.20 presents figures for the cost of US wind turbine installations as collated by the US Department of Energy (US DOE). Here again a fall in costs can be seen and again this can primarily be attributed to the technology learning curve. In 1982 the average cost of wind power was $4,300/kW but this had fallen to $2,300/kW by 1990 and $1,400/kW by 2000. In the case of wind power, however, that represented the lowest price that has so far been achieved. The effect of the fall in value of the US dollar combined with the steep rise in the cost of materials such as iron and copper have served to push prices higher, so that in 2008 the average price was $1,900/kW.

Table 4.21: Annual wind turbine capacity additions (MW), 2009

	Annual capacity addition (MW)
1980	10
1985	420
1990	200
1995	1,310
2000	3,800
2001	6,500
2002	7,200
2003	8,331
2004	8,189
2005	11,471
2006	15,042
2007	19,989
2008	27,056
2009	37,500

Source: Business Insights[35], Global Wind Energy Council   Business Insights Ltd

Figure 4.19: Annual wind turbine capacity additions (MW), 2009



Source: Business Insights, Global Wind Energy Council   Business Insights Ltd

Wind turbine manufacturers will have been able to achieve some economies of scale but nothing like those for solar cell production. In the period between 2003 and 2009 when solar cell production increased by approaching thirteen times, wind turbine production increased by only 4.5 times, as shown in Table 4.21. Mass production cannot be introduced into wind turbine manufacturing in the same was as with solar cells and that may be why, even though the modern development of both technologies dates from the 1970s, solar cell manufacturers are able to achieve better price reductions today than wind turbine manufacturers.

The learning curve and economies of scale tend to reduce technology costs. Other factors can cause them to increase. One of the most significant is legislation. New regulations have had an enormous effect on the economics of some power generation technologies in recent decades. The cost of coal-fired power generation has increased as a result of the introduction of legislation to control sulfur and nitrogen oxide emissions and it is set to rise still further as controls over CO_2 emissions are introduced. Coal-fired power generation is a mature technology and the learning curve reduction of prices has virtually disappeared. Even so there are improvements in the technology under development which could provide a further increase in efficiency and at least partly counterbalance the expected price rises.

The cost of coal generation could be close to doubled by the requirement to capture and store CO_2. As the US EIA figures in Table 2.3 showed, the overnight cost of an IGCC power plant with carbon capture is predicted to be $3,424/kW while the cost of a similar plant without capture and storage is $2,401/kW while in Table 2.2, figures from Lazard suggest the cost of pulverized coal plant without carbon capture of at a minimum $2,800/kW could rise to $5,925/kW with capture and storage.

These increases as a result of expected changes in legislation are large but the most dramatic example in recent history of the effect of regulatory changes on the cost of a technology were seen in the US when new safety regulations were introduced for nuclear power plants. In 1972 the Maine Yankee nuclear power station was built for around $200/kW. Twenty five years later the last nuclear power station to be completed in the US cost $2,000/kW, ten times higher. Inflation over the same period would have been expected to increase the cost by a factor of two of three times.

It may not always be possible to predict such regulatory changes but they are rarely unexpected. There should be little doubt, for example, that the global warming debate will lead to carbon sequestration becoming mandatory in many parts of the world by the end of the next decade. Companies that chose to ignore the clear signs may pay a price for their decision in years to come. For, without doubt, fossil fuel-fired power station electricity is going to become more expensive.

Chapter 5

The environment: lifecycle analysis, CO_2 emissions and the cost of carbon

Chapter 5 The environment: lifecycle analysis, CO_2 emissions and the cost of carbon

Introduction

The previous three chapters have been concerned with the economic performance of power generating plants. This chapter will look at some environmental measures of performance, and in particular the results of lifecycle analyses. A lifecycle analysis looks at inputs and outputs over the complete lifetime of a power plant. The levelized cost model examined in Chapter 2 is a type of lifecycle analysis, one concerned specifically with financial inputs and outputs. Others look at energy and emissions in order to gauge the performance by alternative yardsticks.

The environmental impact of industrial processes including power plants is becoming of increasing importance as global industrial volumes grow. This is particularly true of power generation which can have a significant impact on the environment. Ideally the performance of a power station would be judged by a single parameter, its economic efficiency, but with that efficiency taking account of any environmental impact it may have and the cost of that to society. Today some of the environmental cost of power generation is included in the levelized cost. This cost is included where legislation requires power plant operators to limit emissions of certain pollutants such as sulfur dioxide and nitrogen oxides. Where this is necessary, the cost of equipment required to control these emissions is included in the levelized cost analysis. However there are a wide range of other environmental factors that are not taken account of in the economic analysis. Other lifecycle analyses can provide some insight into the size and importance of these factors. Two of these will be considered here, lifecycle energy analysis and lifecycle carbon emission analysis.

Lifecycle energy analysis

One alternative way of looking at the performance of a power plant is by examining its performance in terms of energy efficiency. This is the object of a lifecycle energy analysis. A lifecycle energy analysis totals all the energy required to produce the components that are used to construct a power station (including the energy involved in its actual construction) and all the energy it consumes during its lifetime. Energy required to decommission and dismantle it may also be included. The total is then compared with the amount of energy the station actually produces in the form of electricity over its lifetime.

The result of a lifecycle energy analysis can be presented in a number of different ways. One is simply to express how many units of electricity a plant produces for each unit of energy it consumes, often expressed as a percentage. The actual result depends on whether the lifecycle energy input total includes the energy contained in the energy source from which electricity is produced. In the case of a fossil fuel power plant this is the energy content of the fossil fuel and in a wind plant it is the energy in the wind which passes through the turbine blades.

Most power plants appear alarmingly inefficient if the fuel, wind or other energy source input is included. By this yardstick a wind energy plant is only 12% efficient (it produces 0.12 units of electricity for every unit of energy is consumes) and a solar photovoltaic plant is around 4% efficient while a modern coal-fired plant is 40% efficient and a natural gas-fired combined cycle plant 43% efficient[36]. These figures reflect the fact that a wind turbine can only extract a small proportion of the energy contained in the wind and a solar plant less still from sunlight, while a gas-fired combined cycle plant can convert more than half the energy in the natural gas it burns into electricity.

Looked at this way, renewable energy plants do not appear very attractive. However there is a difference between the energy sources used by renewable and fossil fuel power stations. In the case of the former the energy source is often free and inefficient utilization will not have any harmful effect. This is not true of fossil fuels (and the same applies, broadly, to biomass for combustion too) since the fuel is still all burnt and so the less electricity is extracted from each unit of fossil fuel energy, the greater the waste per unit.

A perhaps more useful yardstick is provided when the energy source is not included in the lifecycle analysis for any type of plant. When the fuel energy is excluded, renewable technologies generally show much better relative performance. When source energy costs are excluded, a useful way of expressing the results of a lifecycle energy analysis is by using a factor called the energy payback ratio. This figure is calculated by taking the total amount of energy a power plant produces during its lifetime and dividing it by the total amount it consumes (excluding fuel) over the same period. The result is the payback ratio, in units of energy produced for each unit of energy consumed.

Table 5.22 shows energy payback ratios for a range of power generating technologies as collated by the Canadian utility Hydro Quebec. (In reading these figures it should be noted that Hydro Quebec operates a large hydropower capacity.) On the basis of the figures in Table 5.22, hydropower has by far the best energy payback ratio with a range of values of between 170 and 280. Wind power, the second best in the table, has an energy payback ratio of between 18 and 34 while nuclear power also scores relatively well with a payback ratio of 14-16.

Of the other renewable technologies included in the table, electricity from waste biomass is the best performer with an estimated ratio of 27. A biomass plant burning dedicated crop biomass fuel only achieves around 3-5, similar to a solar photovoltaic power plant which has a payback ratio of 3-6. This last figure may require explanation; production of silicon for solar cells is an energy intensive process generally requiring large quantities of electricity. Thin film cells which are based on different materials that require less energy to produce might achieve an energy payback ratio of 20-30 in the near future depending on cell lifetime[37].

Table 5.22: Energy payback ratios based on lifecycle assessment*

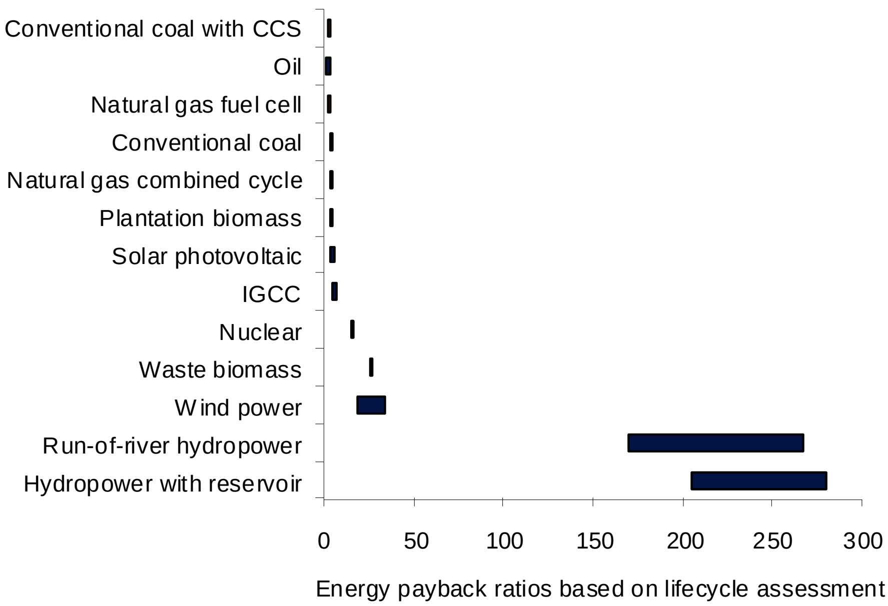
	Payback ratio
Hydropower with reservoir	205-280
Run-of-river hydropower	170-267
Wind power	18-34
Waste biomass	27
Plantation biomass	3-5
Solar photovoltaic	3-6
Nuclear	14-16
Natural gas combined cycle	3-5
Natural gas fuel cell	2-3
Oil	1-3
Conventional coal	3-5
IGCC	4-7
Conventional coal with carbon capture and storage	2-3

* Energy Payback Ratio = the total energy produced during the lifespan of the system, divided by the energy required to build, maintain and fuel it.

(The same ratio is called External Energy Ratio by the National Renewable Energy Laboratory, to indicate that it does not take into account the inherent energy in the fuel burned in power stations.)

Source: Hydro Quebec[38] Business Insights Ltd

Figure 5.20: Energy payback ratios based on lifecycle assessment



Source: Hydro Quebec Business Insights Ltd

Fossil fuel-fired power plants have much lower energy payback ratios than most renewable technologies. Natural gas fired combined cycle plants and coal-fired plants have payback ratios of 3-5[39], similar to that of a plantation biomass power plant, which is to be expected since they use similar technologies. An integrated gasification combined cycle (IGCC) plant might achieve between a payback ratio of between 4 and 7. Meanwhile a natural gas fired fuel cell is only rated at a payback ratio of 2-3, similar to that of a coal-fired power plant with carbon capture and storage.

These figures tell us something important about the performance of these technologies but they also exclude a lot. They give no indication, for example of the amount of environmental damage each technology might be responsible for. Other lifecycle analyses can provide that sort of data.

Lifecycle CO_2 emissions

Another type of lifecycle analysis examines the emissions produced by a power plant over its lifetime. Such studies might look at sulfur dioxide or nitrogen oxide emissions but the most widely considered lifecycle analysis of this type today is concerned with carbon or CO_2 emissions. Examples of such studies can be found for biomass plants[40], natural gas combined cycle[41] and wind plants[42]. As with energy analysis above, such studies seek to measure the total emissions of CO_2 associated with the construction, operation and the eventual decommissioning of a power station. Total emissions themselves provide an interesting figure but this figure is more useful when it is divided by the total electricity production from the plant in order to arrive at the amount of CO_2 emitted for each unit of electricity produced. Such an analysis might also look at how this parameter varies depending on how the power plant is manufactured. For example the emissions for a solar cell will drop significantly if silicon is produced using electricity from a renewable energy source rather than from a fossil fuel source.

A lifecycle greenhouse gas analysis is not simple to carry out, as the studies cited above will show, and in practice certain simplifications are often adopted in order to render the task manageable. One method is to construct an inventory of all the materials employed in the construction of a power plant, all those required for its operation and those involved in its decommissioning and then convert these inventories of materials into greenhouse gas inventories by using widely available tables which show the greenhouse gas emissions associated with the production of each of the materials involved.

As an alternative to producing an inventory of materials, an inventory of costs can be assembled instead. This can then be converted into greenhouse gas emissions by using available figures for the greenhouse gas intensity[43] of the economy in which the construction is taking place. Both these approaches involve approximations since they rely on data that is not directly taken from the construction of a power plant. Even so, both can provide useful data.

Whatever method is used to arrive at the lifetime greenhouse gas emission figures, the limits or boundaries chosen for the calculation can have a significant effect on the final outcome. For example, the mining and refining of uranium in order to make fuel for a nuclear power plant makes a major contribution to its overall emissions and if these are omitted then the final figures will be significantly underestimated. Or, when considering renewable technologies such as wind and solar power, it is necessary to consider how backup power systems should be assessed and whether the contribution from these should be included in the final figure.

With these caveats in mind, Table 5.23 presents figures for lifecycle emission of CO_2, sulfur dioxide and nitrogen oxides from a range of power generating technologies from a report prepared by the World Energy Council. For CO_2 emissions, the figures show broadly the expected pattern with fossil fuel plants emitting much more per unit of electricity generated than renewable plants. Coal and lignite plants produce the most emissions, between 770t/GWh and 1,370t/GWh. A natural gas plant produces between 400t/GWh and 500t/GWh while a heavy oil fired plant emits 660-870t/GWh according to these figures.

Carbon capture and sequestration will significantly reduce the amount released into the atmosphere. Applying carbon capture and sequestration to a coal-fired plant can bring emissions down to between 130t/GWh and 250t/GWh. For a combined cycle plant with carbon capture the overall emissions are expected to be 250t/GWh.

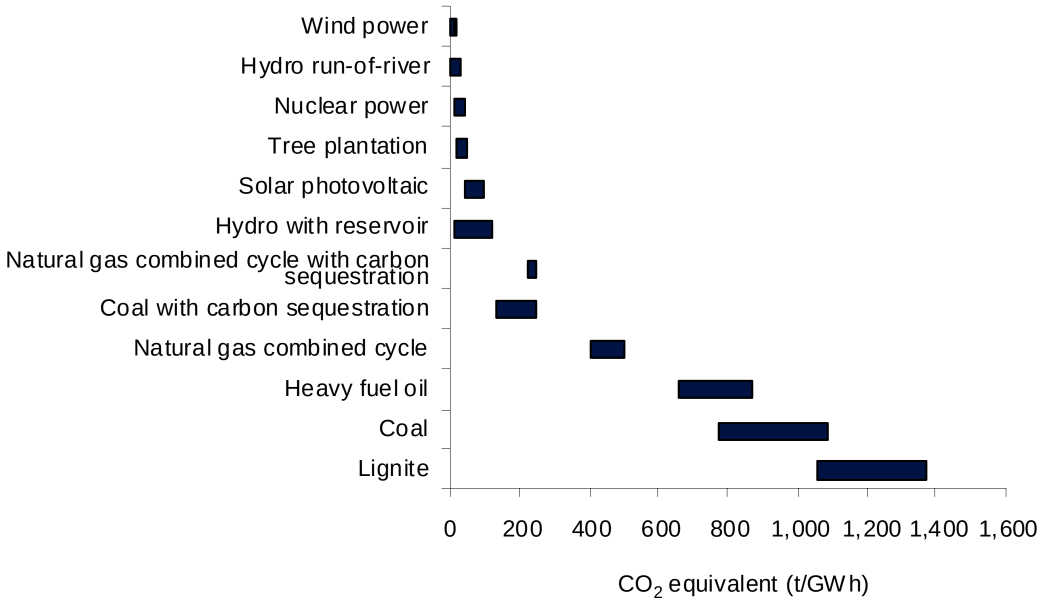
Renewable energy plants all perform much better than any of the fossil fuel plants. A run-of-river hydropower plant is expected to release between zero and 30t/GWh while a hydro plant with a reservoir will emit 10-120t/GWh, much of this related to the energy used for dam construction and construction materials (concrete, in particular, has a relatively high carbon intensity). Wind power plants emit 20-50t/GWh, biomass plants burning dedicated crops will release 20-50t/GWh and a solar photovoltaic plant 40-100t/GWh. As already noted, the relatively high level of emissions associated with solar cells is due to the electricity required to manufacture silicon. Meanwhile a nuclear power plant will release zero to 40t/GWh, among the lowest in the table too.

Table 5.23: Lifecycle emissions from power generating technologies

	CO_2 equivalent (t/GWh)	Sulfur dioxide (kg/GWh)	Nitrogen oxides (kg/GWh)
Lignite	1,060-1,370	430-2,830	790-2,130
Coal	770-1,090	330-3,600	500-2,230
Coal with carbon sequestration	130-250	-	-
Heavy fuel oil	660-870	620-5,260	750-1,450
Natural gas combined cycle	400-500	0-325	100-1,400
Natural gas combined cycle with carbon sequestration	250	-	-
Solar photovoltaic	40-100	100-320	80-1,330
Hydro with reservoir	10-120	20-60	0-10
Hydro run-of-river	0-30	0	0-10
Tree plantation	20-50	40-300	350-690
Wind power	10-20	20-60	20-80
Nuclear power	0-40	10-160	10-240

Source: World Energy Council[44] Business Insights Ltd

Figure 5.21: CO_2 emissions from power generating technologies (t/GWh)



Source: World Energy Council

Business Insights Ltd

The emissions of sulfur dioxide and nitrogen oxides also show fossil fuel power plants to be the heaviest emitters. Sulfur dioxide emissions are generally associated with lignite, coal and heavy oil combustion and the upper figures in the table are for plants without sulfur scrubbers. Natural gas-fired plants do not normally emit sulfur and the upper figure in the table, 325kg/GWh, is for a single plant in the US. Many others emit none. The figures for plants with carbon capture are theoretical but these plants will be expected to have very low sulfur and nitrogen emissions too.

Among the renewable technologies, solar photovoltaic plants again have relatively high emissions for reasons already noted and a biomass plant burning woody crop fuel will emit some sulfur although the quantities are likely to be small, as the table indicates. The sulfur emissions associated with a nuclear power plant are relatively low, but not insignificant.

Emissions of nitrogen oxides follow the same pattern as sulfur dioxide with the exceptions that natural gas-fired combined cycle plants can emit significant quantities, as the table suggests, and biomass plants will also produce nitrogen oxides in relatively high amounts since they are based on a combustion technology. In the case of both nitrogen and sulfur emissions, the hydropower plant offers the best overall performance on the basis of these figures.

Placing a price on carbon

As the international consensus on controlling the emission into the atmosphere of CO_2 from industrial plants hardens, the value placed on emission of a tonne of carbon is going to play a pivotal role in determining the future direction of power generation. Lifecycle CO_2 emission rates such as those discussed above and shown in Table 5.23 offer a means of differentiating between different technologies on the basis of their CO_2 emission performance. In practice, however, it will be daily or annual emissions from a power plant that will become important economically. These emissions will determine the economic penalty each power plant must pay in order to continue to operate because in the future there will be a price to pay for each tonne of carbon or CO_2 emitted.

How much should each tonne of carbon cost the emitter? One theoretical starting point is to assume that the cost of each tonne of carbon emitted should be equal to the cost to society of emitting that tonne of carbon in terms of the damage it does to the global environment. Carrying out such a calculation involves estimating the effect of the emission of CO_2 on global temperatures and then deterring how these temperature rises affect climate. The effect of these changes on climate must then be fed into an economic model to determine their social impact and to put a price on this impact.

The effects of global warming are being predicted to take place over an extremely long period of time so the precise outcome of emitting one tonne of carbon will depend on the rate at which technical solutions to the problems created by climate change are developed. At every stage there is a good deal of uncertainty. Even so there have been several attempts to put a price on carbon emissions[45]. One recent example can be found in the Stern Review[46]. This review examined the economic consequences of global warming and it put the cost of carbon at \$312/tonne C or \$85/tonne CO_2. However, as the previous reference above details, this is considerably higher than a number of other similar estimates. And the Intergovernmental Panel on Climate Change recently concluded that most of the main carbon mitigation technologies for power generation would become economically feasible with a carbon price of between \$75-\$185/tonne C (\$20-\$50/tonne CO_2) which, if correct, should cap the eventual cost. Meanwhile recent estimates within the EU have suggested that a price of €100/t CO_2 will be necessary by 2020 to drive investment in renewable technologies.

At present these estimates are mainly of theoretical interest. It will require international consensus to agree a basis for costing carbon and then to determine how this cost is to be imposed. Some progress towards this was made in Copenhagen in December 2009 but final agreement still appears a long way off. Consensus is currently growing around a proposal to extend the Kyoto agreement until a replacement can be agreed but that still requires considerable movement from major emitters such and China, India and the US. In the meantime regions such as the European Union have already started to act unilaterally by imposing an economic system to control the emissions of carbon. Here we can already see a carbon emission penalty system in operation.

There are two main ways in which a carbon charging system can be introduced. One is to place a tax on carbon. The alternative system, preferred by the European Union and now in operation, is the Cap-and-Trade system under which regional and national emission limits are set and certificates (in this case EU emission allowances) are then issued equivalent that amount. At the end of each accounting period every emitter must produce certificates to back each tonne of carbon they have emitted or otherwise pay a severe economic penalty. These certificates can be traded on a carbon certificate market through which the cost of each certificate is determined by supply and demand.

In fact the cost of certificates can also be influenced by the issuer (in this case the EU or national governments within the EU) because the issuer will decide the size of the emission cap and therefore how many certificates are available to trade. The market price will also be affected by whether these certificates are simply issued free of charge to emitters (as happened during the first period of the EU system) or whether the latter must pay for the certificates through a national auction.

The alternative to a Cap-and-Trade system is a straightforward carbon tax. Under this system each emitter will pay a tax for each tonne of carbon emitted. The cost of each tonne of carbon can then be set by governments allowing, in principle, more precise control over rates of emission since if emission targets are not being met, the tax can be increased. In the case of a carbon tax, there is the question of what is to be done with the revenue raised (the same question arises where certificates are sold to emitters in a Cap-and-Trade system). Governments will be free to decide whether this revenue is to be used for environmental improvement, to reduce the income tax burden of the country's inhabitants, to offset the impact of the carbon tax for poorer sections of the population or in any other way.

There are arguments in favor of both schemes. A carbon tax can be targeted, by taxing energy for example, to provide precise incentives. On the other hand a market-based system is easier to integrate internationally. In practice it is most likely that a mixture of both will eventually come into use to control carbon emissions. However implemented, it would be prudent for all investors in the power sector to assume that emitting carbon will become more costly over the next decade.

Actual carbon costs: the European Trading Scheme

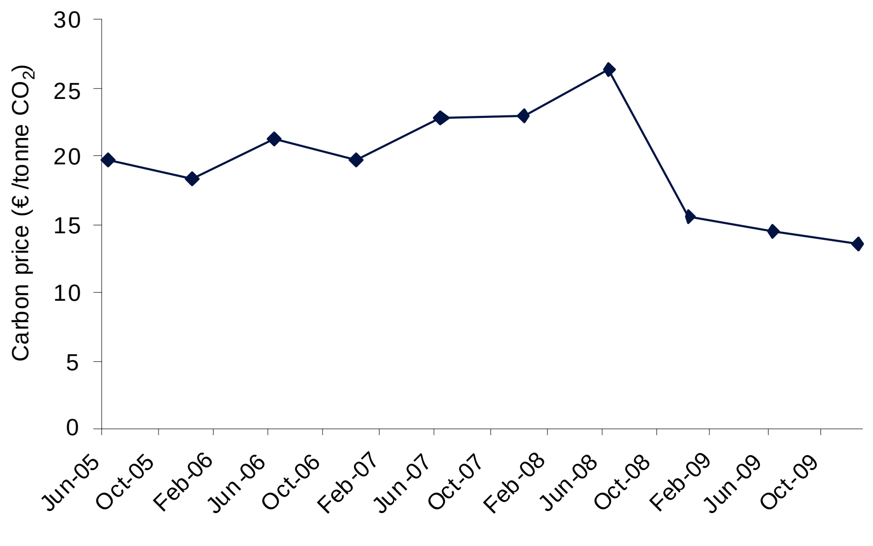
Some idea of the market price of carbon today can be gained from the European Trading Scheme (ETS) discussed above which has already provided some signals about how such a market works. Figures showing the historical cost of carbon in the scheme are presented in Table 5.24. During the first period of the ETS, which ran from 2005 until the end of 2007, EU emission allowance futures traded on the European Climate Exchange (ECX) at around €20/tCO_2 although there were significant fluctuations in spot values beyond this band, particularly at the beginning of the scheme when the value was about €7/tCO_2 and at the end of the period when the value collapsed (this is not reflected in futures where the price is determined ahead of time and is a bet on the market). At the beginning of the second period of the ETS, which runs from 2008 to 2012, the value of a tonne of CO_2 on the futures market was still around €20-€30 but by the end of 2008 futures were trading at a much lower value, closer to €15/tCO_2. This price persisted into 2010.

Table 5.24: EU Emission Trading Scheme carbon prices (€/tonne CO_2), 2010

	Price (€/tonne CO_2)
June-05	19.7
December-05	18.3
June-06	21.3
December-06	19.7
June-07	22.8
December-07	23.0
June-08	26.3
December-08	15.5
June-09	14.4
December-09	13.5

Source: ECX[47] Business Insights Ltd

Figure 5.22: EU Emission Trading Scheme carbon prices (€/tonne CO_2), 2010



Source: ECX Business Insights Ltd

The relatively low price of CO_2 in the ETS is presenting problems both for companies and for policy makers within the EU. At the level at which it was trading at the beginning of 2010, the price of a tonne of CO_2 does not provide sufficient incentive to generators to move away from fossil-fuel based generation and invest in renewable technologies. Part of the problem is associated with the recession which has led to cutbacks in production across the EU and a consequent reduction in CO_2 emissions. This means that companies are requiring smaller emission allowances, leading to a fall in their value. The cap levels and the way certificates have been allocated is also a source of concern.

A cap-and-trade system of this type is supposed to provide a means to influence the rate of environmental emissions by providing price signals. However if those signals are too low the system simply will not work. One solution being proposed is to establish a floor, a price below which the cost of a tonne of CO_2 will not be permitted to fall. Alternatively adjustments to the cap could be introduced so that the total emissions limit is lowered. Estimates suggest that in 2020 the EU allowances may be trading for €30/tCO_2, far lower than the €100/tCO_2 predicted to be necessary to encourage the required investment. If this is to be corrected, then both measures, and perhaps others will be needed but any new measures are likely to prove controversial and politically difficult to implement.

Chapter 6

Factors which distort the price of electricity

Chapter 6 Factors which distort the price of electricity

Introduction

The cost of a unit of electricity should be based on the cost of its production, an additional element for its transportation to the user and a margin associated with the extraction of profit for shareholders, for future investment or for both. If all the inputs are priced fairly and all the outputs are charged fairly then a comparison of the final cost of electricity from a range of different technologies will fairly represent their performance.

There are a number of factors which often fall outside the normal bounds of consideration but which distort this fair comparison. Subsidies are one such factor. Subsidies tend to make one type of technology or one type of fuel more economical than another by distorting its open market cost. Such subsidies may take the form of national support for a particular industry such as coal mining or they may be artificially raised tariffs paid to producers of green energy. In either case the cost of production of electricity from that source is shifted away from the cost in an open market without any subsidy present.

Another set of factors that influence the cost of electricity are externalities. In the case of power generation, externalities are external costs to society associated with the generation of electricity from a particular source which are not included in the cost of production. CO_2 emissions, by affecting global climate, have a significant economic and social effect globally. This is an external effect, an externality, and until recently it has been ignored when costing electricity from carbon emitting sources. As we saw in the last chapter, the cost of carbon is likely to become incorporated into the cost equation of electricity production from fossil fuels soon and sulfur and nitrogen oxide emissions have already begun to be integrated but this is at best only a partial internalization of the externalities associated with their emission which continue, albeit at a lower level, even when capture technology is introduced. Besides, when emissions are captured at a power plant there may be a new externality introduced relating to the capture and storage or re-use of the material. Emission of other materials from fossil fuel combustion such a particulates and heavy metals have significant external effects too.

Renewable plants have externalities associated with them though in general they are of a lower order than those associated with fossil fuels. However there is a further group of distorting factors that are primarily associated with renewable power generation. These are called structural costs since they relate to the costs of adapting conventionally structured electricity transmission and distribution delivery networks to accommodate intermittent and unpredictable sources of electricity. Each of these factors will be considered briefly in this chapter, starting with the last.

Structural costs

Traditional transmission and distribution networks have evolved to support the delivery of electric power from centrally located power stations. These central plants are generally large and their output is delivered as alternating current into a high voltage transmission network which forms the backbone of a national delivery system. Distribution spokes are then attached to the backbone and these take the power, transformed to a lower voltage, to the electricity system customers. Networks of this type have been in operation in many industrialized countries for a century and similar systems are being established in most developing countries too.

Renewable-based electricity generating plants do not usually fit easily into this established arrangement. Most renewable sources of electricity are widely distributed and cannot be concentrated to provide a single, large capacity source. Solar energy is capable of providing a large amount of electricity but usually in small amounts delivered locally. Other types of renewable energy, particularly wind, hydro, wave and ocean sources, are most frequently located at the periphery of national distribution networks where the network is at its weakest and usually at sites remote from cities and industrial centers where demand is high.

There are two additional characteristics of renewable energy that have an impact on their utility to a network, variability and unpredictability. Networks need to modify the way they operate to accommodate both but the two should be distinguished carefully. The output from a tidal power plant is variable but extremely predictable. It will produce electricity twice each day for a period after high tide, an event that can be predicted with extreme precision. A network dispatcher can be certain that (barring shutdowns) the plant will deliver exactly as predicted. But the power will only be available for part of each day.

A solar power plant displays variability too since it will produce electricity during the day but not at night[48]. These diurnal variations are completely predictable. However the output from a solar plant will also vary with the weather. When it is cloudy the output will be lower than when there is no cloud cover. This introduces a level of unpredictability.

Wind power shows none of the regular variations associated with solar or tidal power. It depends on the prevailing weather which can be predicted, though not with anything like the degree of certainty associated with these other types of renewable generation. Even with good forecasting, though, local variations add uncertainty. Wind generation also tends to be variable. Sometimes there will be sufficient wind to generate electricity, sometimes there will not. Thus wind power carries both a high degree of unpredictability[49] and significant variability. This must be taken into account when adding wind generation to a network.

As a consequence of these various characteristics there are two types of structural cost that are associated with the addition of renewable generation to a network. The first is associated with the grid extension necessary to accommodate the new capacity in locations remote from the central backbone. The second is associated with the operational contingencies the must be put in place in order to account for the variability and unpredictability of the renewable source.

Grid extension

Renewable generation interacts with a transmission and distribution system in complex ways some of which may reduce costs while others will increase them. Small renewable generating units such as small wind farms or rooftop solar arrays are often widely dispersed, usually at some distance from central power plants. Such units can act as distributed generation, supplying their power to local users. As such they lead to a reduction in transmission losses compared with the same power being transmitted from a distant central power plant. They may also save money by avoiding the need to upgrade the transmission system as local demand grows. Depending on their type, however, they may either strengthen or weaken grid stability. In the latter case additional cost will be associated with grid stability strengthening measures needed to counteract this weakening effect.

Very large renewable generating plants such as offshore wind farms or a large concentration of renewable plants in a single geographical area, present a different problem. In this situation there is frequently a need to transport large quantities of power from a region which has previously been at the periphery of the transmission system. Extensive grid reinforcement is often necessary to make this possible.

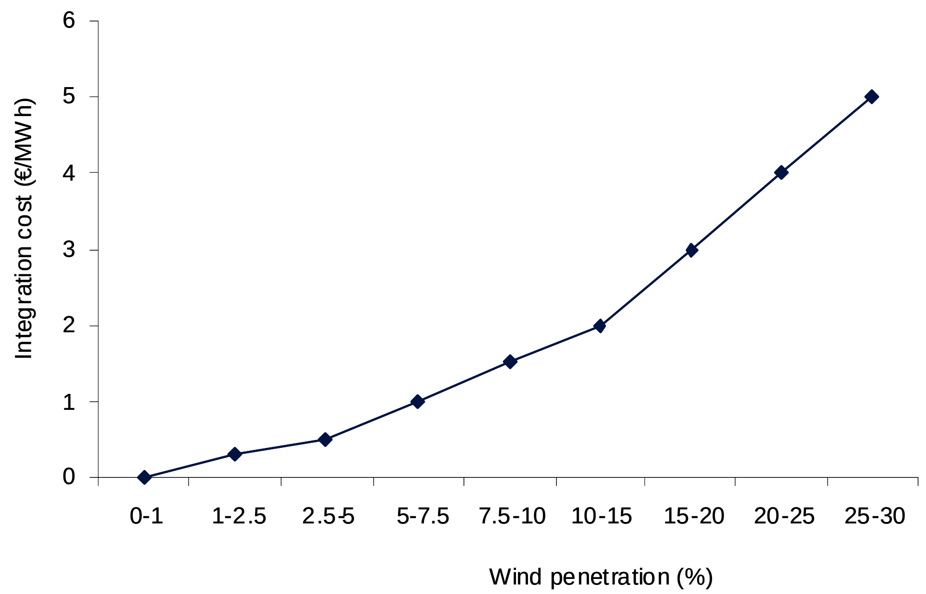
Results from a range of European national studies collated by an EU sponsored study found that there was a relatively linear increase in the cost of grid extension based on the percentage of renewable generation (primarily wind) included in the generation mix[50]. These results are shown in Table 6.25. As the table shows, the cost of a small quantity of wind generation (up to 1%) is negligible but the costs soon begin to rise so that by the time the percentage reaches 10%, the cost is around €2/MWh. By the time the wind penetration has reached 30%, the cost is €5/MWh or half a cent for each kWh generated.

Table 6.25: Grid extension costs as a function of wind penetration

Wind penetration (%)	Integration cost (€/MWh)
0-1.0	0
1.0-2.5	0.3
2.5-5.0	0.5
5.0-7.5	1
7.5-10.0	1.5
10.0-15.0	2
15.0-20.0	3
20.0-25.0	4
25.0-30.0	5

Source: European Union[51] Business Insights Ltd

Figure 6.23: Grid extension costs as a function of wind penetration



Source: European Union Business Insights Ltd

The European Union has established a target of deriving 20% of its energy from renewable sources by 2020. In order to achieve its part, the UK has a set a national target of generating 20% of its electricity from renewable sources by 2020. If this target it to be met, most of the additional energy will come from wind farms, many offshore since this is the only the renewable source the UK has available to generate the required amount of energy within this time-frame.

Table 6.26: Additional annual transmission and distribution costs in 2020 associated with increasing UK renewable contribution above 10 per cent after 2010[52]

	Transmission costs (£m/y)	Distribution costs (£m/y)	Total costs (£m/y)
20% renewables	6-91	-29	0-114
30% renewables	8-242	13-55	5-297

Source: UK Department of Trade and Industry[53] Business Insights Ltd

A UK study[54] carried out soon after the turn of the century looked at the cost implications of increasing the amount of electricity demand met by renewable sources in the UK from 10% renewable generation in 2010[55] to 20% or 30% of total generation by 2020. Some of the results of the study, relating to transmission and distribution costs, are shown in Table 6.26. These suggest that if renewable generation is increased to 20% by 2020 from a supposed 10% in 2010, the annual additional transmission costs will be between £6m/y and £91m/y. Additional annual distribution costs range between -£6m/y (reflecting the potential savings from distributed generation based on renewable sources) and £23m/y. For 30% renewable generation by 2020, the figures are significantly higher, £8m/y - £242m/y additional transmission costs and £13m/y - £55m/y additional distribution costs. All costs are in £2002 and are likely to be notably higher in 2010. In each case the low cost option in the study involved a mix of reliable renewable sources such as biomass and unreliable sources such as wind. The high cost option involved only intermittent sources.

Balancing costs

The figures presented in Table 6.26 represent only a part of the additional charges that would be incurred if renewable generation were from increased from (a supposed) 10% in 2010 to 20% or 30% by 2020. Operational or balancing costs make up a much greater part. These costs are directly related to the intermittency of the renewable sources being considered, primarily wind generation.

Balancing costs are incurred because of the capacity that has to be held ready to replace intermittent sources if their output is not available. There is also the opposite situation where renewable output (wind output in the case of the UK) must be curtailed because it exceeds demand during low demand periods. Synchronized or spinning reserve costs may also be incurred, particularly where renewable capacity is unable to help reinforce the grid.

The UK study cited above found that increasing renewable generation from 10% in 2010 to 20% in 2020 would give rise to balancing costs of £143m/y - £284m/y while for 30% penetration this would rise to £319m/y - £624m/y. This would mean a total cost of up to £921m/y for integration and balancing costs, not far short of £1bn/y. Per unit of output, this would be equivalent to up to £2.2/MWh over all generation or an additional £10.8/MWh if only the renewable output is considered. To put this in perspective the study estimated that in £2002, the wholesale value of electricity generated in 2020 would be about £9bn.

The UK figures imply that balancing costs will represent a major factor affecting the integration of renewables. However this also depends on the structure of the network. One of the best ways of accommodating intermittent sources is by increasing energy storage capacity. This may be expensive to build but permits power from all renewable sources to be managed with ease as well as reducing peaking costs across the network.

The effect of storage is clearly illustrated in a study of the costs of introducing wind power into Nordic countries and Germany. This study found that the balancing cost varied from country to country. Balancing costs were significantly lower where there was a major contribution to installed capacity from hydropower since hydro output is easily modulated to adapt to differing wind outputs and is thus operationally equivalent to storage capacity. Thus the operational costs associated with 20% penetration in Norway and Sweden were €0.5/MWh and €0.66/MWh, notably lower than those found in the UK study, whereas in Germany costs were similar to UK costs, approaching

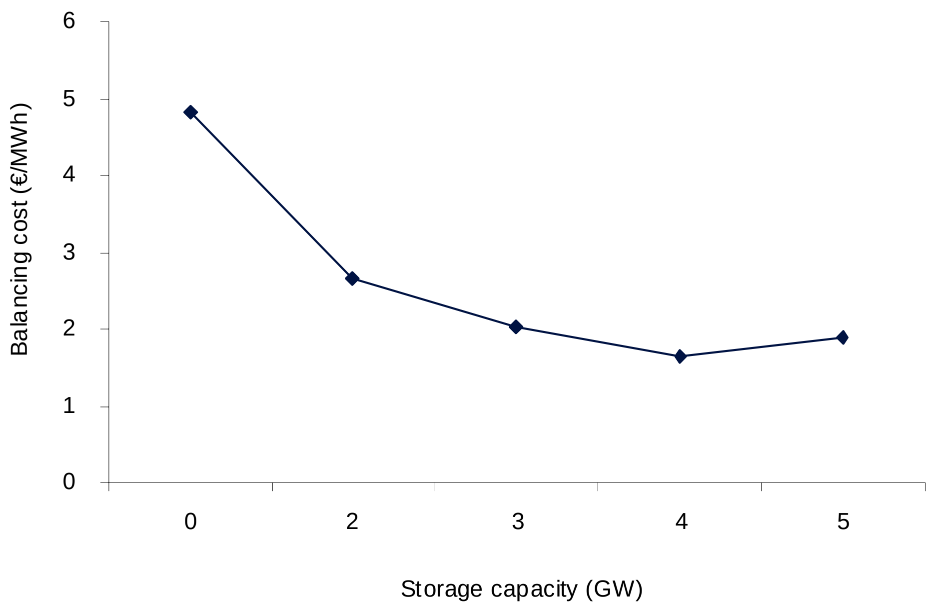
€3/MWh[56]. (There were other effects which pushed up the cost in Germany in addition to lower hydro capacity.)

Table 6.27: Balancing costs for 20% grid wind penetration with energy storage

Storage capacity (GW)	Balancing cost (€/MWh)
0	4.83
2	2.65
3	2.02
4	1.64
5	1.88

Source: European Union[57] Business Insights Ltd

Figure 6.24: Balancing costs for 20% grid wind penetration with energy storage



Source: European Union Business Insights Ltd

Table 6.27 presents further figures showing the effect of storage capacity on balancing costs, this time from an EU study. For the scenario considered in this study, in which 20% wind penetration was introduced into a grid, the balancing cost with no storage capacity was estimated to be €4.83/MWh. This started to fall as storage capacity was introduced, reaching a minimum of €1.64/MWh with a storage capacity of 4GW. Beyond this the balancing cost began to rise again as the cost of energy storage began to outweigh its advantage. In this case the minimum balancing cost is close to that found in the UK study. These figures are for one network configuration. The optimum amount of storage will vary with network size and the composition of generating capacity.

Capacity credit

The assessment of balancing or integration costs associated with renewable energy sources is complex. As modeling techniques are refined, so the conclusions change. Additionally network developments, particularly some of those associated with small distribution networks and mini grids are changing the way in which renewable sources are integrated, again affecting their value.

A related, and often vexing, issue that is often raised when the value of renewable generation is under discussion is that of capacity credit. There is a well-oiled argument used to damn wind power which asserts that since the wind does not blow all the time a wind turbine cannot always produce power and therefore there must always be conventional capacity equivalent to its capacity available to replace it. If we ignore the fact that no power plant can run continuously, then considering a single wind turbine added to the grid this argument is broadly true. However once the number of wind turbines rises above one the argument starts to lose its validity because when one turbine is not turning, another may be, particularly if they are geographically separated.

This suggests that renewable generation such as wind power has a positive capacity value to a grid, even if it is not its nameplate capacity. In order to quantify this, utilities today try to establish a quantity called the capacity credit for each type of renewable generation attached to its network. Broadly, the capacity credit of a block of renewable generating capacity is the amount of conventional generating capacity it can replace on the network without impairing network security. Like balancing and integration costs, capacity credit can be difficult to assess but as understanding of renewable generation improves, so does the ability to derive accurate capacity credit values.

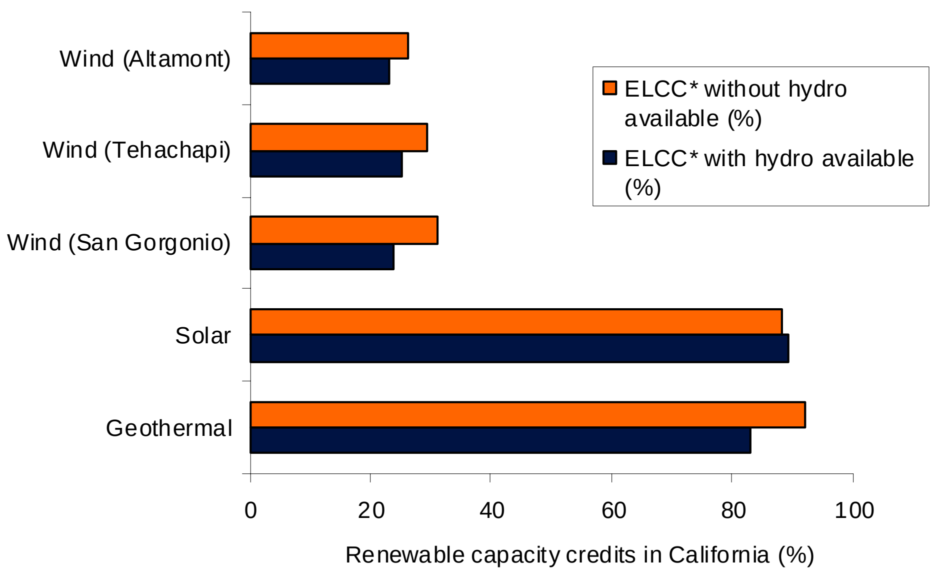
Table 6.28: Typical renewable capacity credits in California (%)

	ELCC* with hydro available (%)	ELCC* without hydro available (%)
Geothermal	83	92
Solar	89.5	88.4
Wind (Altamont)	23	26.1
Wind (San Gorgonio)	23.5	31.1
Wind (Tehachapi)	25.2	29.1

* ELCC=Effective Load Carrying Capacity

Source: California Energy Commission[58] Business Insights Ltd

Figure 6.25: Typical renewable capacity credits in California (%)



Source: California Energy Commission Business Insights Ltd

Table 6.28 shows some figures from the California Energy Commission for a quantity called the Effective Load Carrying Capacity (ELCC) of renewable sources in California. This quantity is essentially the same as capacity credit. The table contains two sets of figures, one calculated when hydro capacity is available in California and the second when it is not. Hydropower provides an extremely flexible source of electricity because, as noted above, it can often act like energy storage ready to be brought on line extremely quickly. So, perhaps counter-intuitively, when hydro capacity is hypothetically removed from the network the value of other renewable sources in terms of their capacity credit often rises, as the table shows.

The renewable sources with the highest ELCC in California are geothermal (83-92%) and solar power (90-88%). Solar power has a high capacity credit because it can be reliably scheduled to operate during the peak air-conditioning demand period of the day when peaking units might otherwise have to be brought into service. The ELCC for wind power in California varies with the wind site but when hydropower is available on the network it has a value of 23-25% while without the hydro capacity it rises to 26-31%.

These values for wind are probably typical for a network with a reasonably diversified portfolio of generating sources but it will vary, as will the capacity credit of all sources, depending on the particular mix of technologies and the demand curve the network must supply[59].

Externalities

Externalities cover a wide range of costs associated with power generation from different types of plant but which are not borne by the plant and consequently do not affect the cost of electricity from the plant. One of the largest group of externalities applying to fossil fuel power stations and are associated with emissions ranging from CO_2 to sulfur and nitrogen oxides, heavy metals and dust and particulates. Between them these contribute to global warming, to acidification of rainwater with associated damage to forests, lakes and buildings and to a wide range of health problems. All these effects have an economic cost that is not directly borne by the power generator. If that cost was levied on the producer, the cost of electricity from these power plants would rise significantly.

Other externalities will apply to many more types of power station. Plants that require cooling water may contaminate water supplies, either with added pollutants or simply by raising the temperature of the water. Hydropower stations, particularly those associated with large dams, can change downstream environments dramatically. A wind farm may affect the value of adjacent land or properties. Operation and maintenance of a power plant will introduce new traffic movements which may affect the quality of life of those who live close by.

The range of effects that are covered by the term externalities is enormous. Consequently estimating their cost is extremely difficult. One of the largest attempts was made by the European Commission with its ExternE programme which has now concluded but which remains a benchmark for such assessments. Some results from ExternE for a range of power generation technologies are presented in Table 6.29.

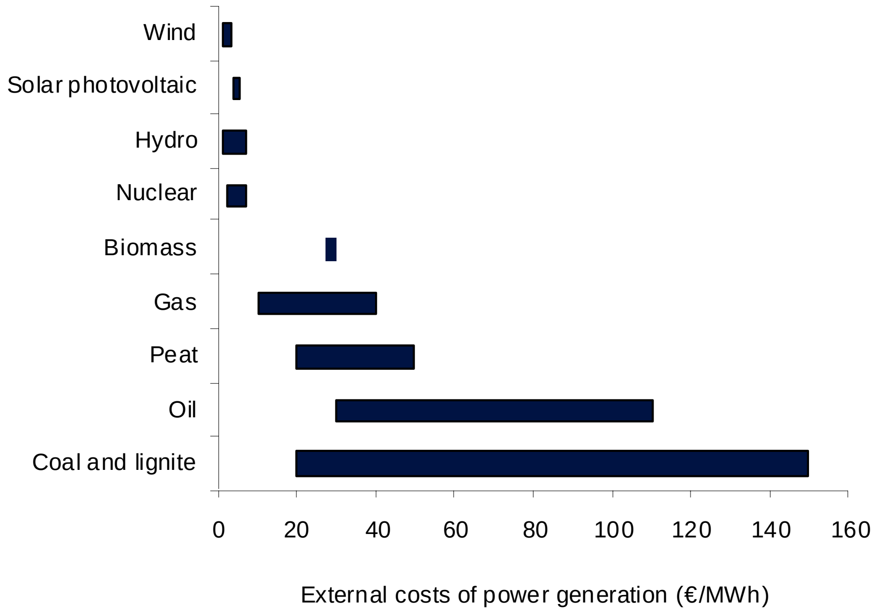
Table 6.29: External costs of power generation (€/MWh)

	External cost (€/MWh)
Coal and lignite	20-150
Peat	20-50
Oil	30-110
Gas	10-40
Nuclear	2-7
Biomass	0-30
Hydro	1-7
Solar photovoltaic	6
Wind	1-3

Source: EU ExternE programme[60]

Business Insights Ltd

Figure 6.26: External costs of power generation (€/MWh)



Source: EU ExternE programme

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As expected, the plants with the highest estimated external costs are coal and lignite power stations with an external cost per unit of power ranging from €20/MWh to €150/MWh depending on the measures taken by the plant to control its emissions. An oil fired plant falls into a similar range, €30-€110/MWh while a peat-fired plant shows slightly better performance in the range €20/MWh to €50/MWh. Natural gas-fired power plants have an estimated external cost, on this assessment, of €10/MWh to €40/MWh, the best of all the fossil-fuel fired plants included in the table.

It is clear from Table 6.29 that all combustion-based technologies fare badly when externalities are considered. Even biomass combustion, with an external cost in the range €0-€30/MWh can be costly in these terms though the much lower range of external costs here reflects the fact that biomass is carbon neutral when it comes to atmospheric emissions. In contrast the main renewable technologies all carry a significantly lower external cost. Wind power, the best performer by this yardstick, has an external cost of €1/MWh to €3/MWh while a hydropower plant is in the range €1-

€7/MWh and a solar plant has a cost of around €6/MWh. Nuclear power also performs extremely well on this basis, with an estimated external cost of €2/MWh to €7/MWh.

The significance of these figures can be seen by comparing them with estimates for the cost of electricity from the same period. A contemporary report[61] suggested that the cheapest source of power was a large hydropower with a levelized cost of $10/MWh followed by nuclear power at $20/MWh, natural gas-fired generation at $30/MWh and coal at $35/MWh. On this basis, the inclusion of external costs would increase the cost of gas-fired power by at least 30% and coal-fired power by over 50%[62]. Clearly, this would tip the economics towards renewable and nuclear power generation. The same study put the levelized cost of wind power at $40/MWh, making it roughly competitive with gas-fired generation when externalities are included.

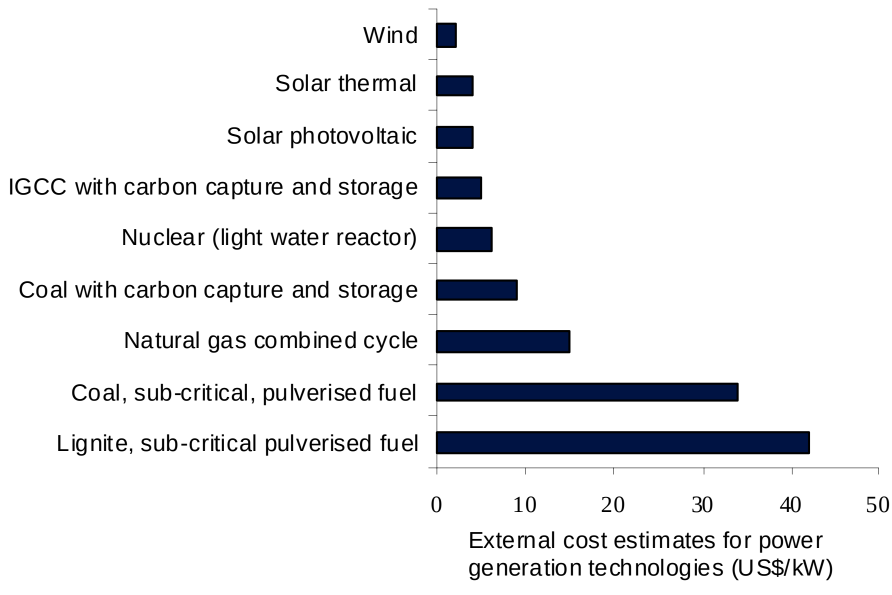
Another attempt at estimating externalities for fossil fuel power generation has been carried out by the International Institute for Sustainable Development in Canada[63]. Based on the results of this study, the median estimate of the cost of coal externalities in Canada was C$39.4/MWh or around 50% higher than the marginal cost of generating electricity from coal which was C$26.0/MWh. Even when the global warming external costs were excluded, the external cost associated with health was still C$17.1/MWh. For natural gas the median external cost was estimate was C$10.2/MWh while for oil it was C$21.8/MWh.

Table 6.30: Australian external cost estimates for power generation technologies, 2009

	External cost (A$/MWh)	External cost (US$/kW) [64]
Lignite, sub-critical pulverised fuel	52	42
Coal, sub-critical, pulverised fuel	42	34
Natural gas combined cycle	19	15
Coal with carbon capture and storage	11	9
IGCC with carbon capture and storage	6	5
Nuclear (light water reactor)	7	6
Solar photovoltaic	5	4
Solar thermal	5	4
Wind	2	2

Source: ATSE[65] Business Insights Ltd

Figure 6.27: Australian external cost estimates for power generation technologies (US$/kW), 2009



Source: ATSE Business Insights Ltd

Meanwhile a further study in Australia confirmed the potentially high cost of externalities associated with fossil fuel power plants in that country[66]. According to this study, the results of which are shown in Table 6.30, external costs for lignite and coal fired power plants are \$42/MWh and \$34/MWh respectively, while the cost for a natural gas fired combined cycle power plant is \$15/MWh.

When carbon capture and storage (CCS) is added, coal-fired plant external costs drop. A conventional plant with CCS has an external cost of \$9/MWh while an integrated gasification combined cycle (IGCC) plant with CCS shows an estimated external cost of \$5/MWh. These figures bring coal-fired generation into line with nuclear power with an estimated external cost - in an Australian context - of \$6/MWh. However they are still above those for renewable source such as solar (\$4/MWh) and wind (\$2/MWh). To put these Australian figures into context, the average wholesale cost of electricity in Australia is \$32/MWh (\$A40/MWh), indicating that the estimated external costs for all operating fossil fuel power plants in the country, none of which include CCS, are extremely significant.

Subsidies

Subsidies can be found in markets of every kind including the power market, where they range from government sponsored research to the artificial reduction of fuel prices. Some subsidies may be targeted at protecting the poor, others at protecting industries that are considered to be of strategic or economic importance. Still others are concerned with promoting new technologies. Of all these types of subsidy within power market, two are most important, fuel subsidies and tariff subsidies. Each has the effect of distorting the market price of electricity relative to that which would pertain if no subsidy were present.

At its simplest a subsidy is a cash payment made by a government to a consumer or producer. However this definition only encompasses a fraction of the ways in which costs can be affected. A broader definition, used by an OECD study, refers to any measure that keeps prices for consumers below market levels, or for producers above market levels or that reduces costs for consumers and producers[67]. This includes not only direct payments but factors such as preferential tax treatment, quota or trade restrictions and public investment in targeted research and development or infrastructure as well as energy sector regulations.

Such subsidies are pervasive and they are usually extremely difficult to quantify. Where they can be quantified, they will normally be specific to an individual country or even a region of a country. There are a number of internationally recognized measures of the level of subsidy. One, called the Effective Rate of Assistance (ERA) quantifies the effect of subsidies on the product in question but requires detailed inputs. Another, developed by the OECD, is the Producer Subsidy Equivalent (PSE) which provides a partial picture of the subsidy in question but is easier to calculate. The Consumer Subsidy Equivalent (CSE), meanwhile, is derived from the difference between the domestic price in question and the world price.

Global subsidy levels associated with the energy industry are difficult to estimate but several studies have tried. One suggests global fossil fuel subsidies of between $130bn and $230bn billion each year[68]. Meanwhile at the G20 summit in September 2009 the global fuel subsidy was said to be $300bn each year. Subsidies in countries outside the OECD generally preferentially support consumers. OECD subsidies are more often targeted at producers.

Fuel subsidies

Fuel subsidies are probably the most pervasive of all the energy industry subsidies. They affect coal, oil and gas in different parts of the world. In some cases these subsidies are intended to keep alive an industry that might otherwise die. Several countries in the EU such as Spain, Germany and Hungary have supported their coal mining industries in this way. In other cases the subsidies are used as a tool by governments to influence their populations by reducing the cost of living. Iran, for example, subsidizes oil and gas for domestic use, leading to massively inflated demand compared to other countries of similar size. Russian fuel has traditionally been subsidized, too, as has that in Indonesia.

As with global subsidy levels, mentioned above, quantifying the size of national fuel subsidies is not easy although again efforts have been made. The German subsidy to its coal industry was estimated by the OECD in 2000 to be close to $4bn. Meanwhile in 1999 a US Department of Energy study found total energy subsidies in the US to be $6.2bn, half of which subsidized fossil fuels and 8% renewables. In 2000 the subsidy from the Indonesian government for oil products was around $4bn, 10% of the state budget. A further study published in 2006 by the IMF[69] assessed the fuel subsidies in a range of countries as a percentage of GDP. The results, predicted for 2005, found Azerbaijan provided subsidies worth 12.7% of GDP, Yemen 9.2%, Jordan 5.8%, Egypt 4.1%, Ecuador 3.6%, Indonesia 3.2% and Bolivia 3.1%. This study was by no means exhaustive and similar levels of subsidy are likely in many other countries.

The International Energy Agency (IEA) also looked at energy consumption subsidies - subsidies that lower the cost of energy to consumers - in its 2006 World Energy Outlook. Figures in this report from non-OECD countries are shown in Table 6.31. Such subsidies are often implemented through price controls on the cost of energy from state-owned companies. (As such they are similar to tariff subsidies - see below.) IEA figures put Russia at the top of the table with annual subsidies in 2005 of $40bn, closely followed by Iran with $37bn. Chinese subsidies were $25bn, those in Saudi Arabia $20bn, India $19bn and Indonesia $16bn. The figures in the table include all the countries with estimated subsidies in excess of $1bn. The IEA report also confirmed that most remaining subsidies within OECD countries target producers rather than being aimed directly at consumers.

Table 6.31: Economic value of fuel subsidies in non-OECD countries ($bn), 2006

	Subsidy value ($bn)
Russia	40
Iran	37
China	25
Saudi Arabia	20
India	19
Indonesia	16
Ukraine	15
Egypt	12
Venezuela	9
Kazakhstan	7
Argentina	7
Pakistan	5
South Africa	4
Malaysia	3
Thailand	3
Nigeria	2
Vietnam	2

Source: IEA[70]

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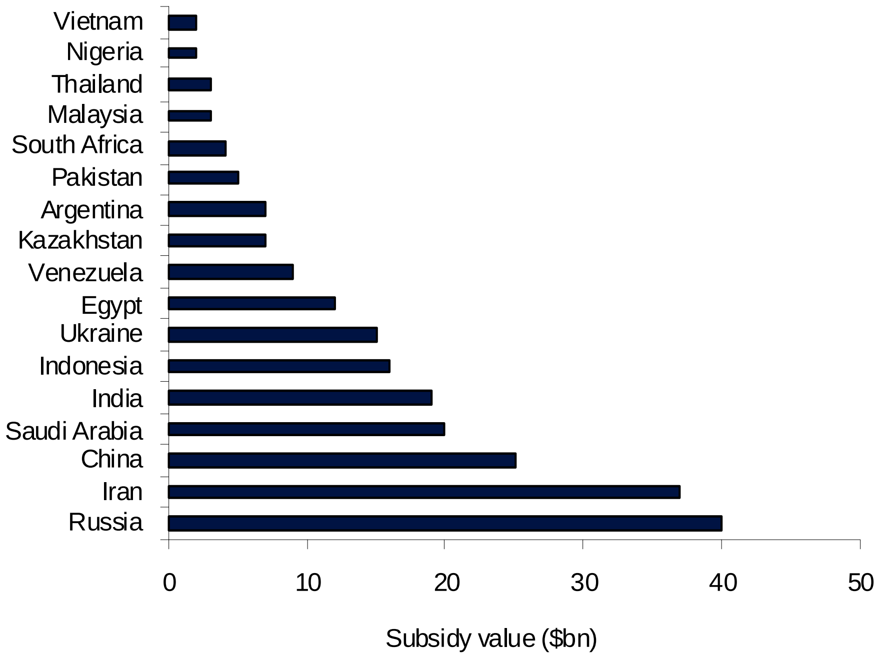
Figure 6.28: Economic value of fuel subsidies in non-OECD countries ($bn), 2006



Source: IEA

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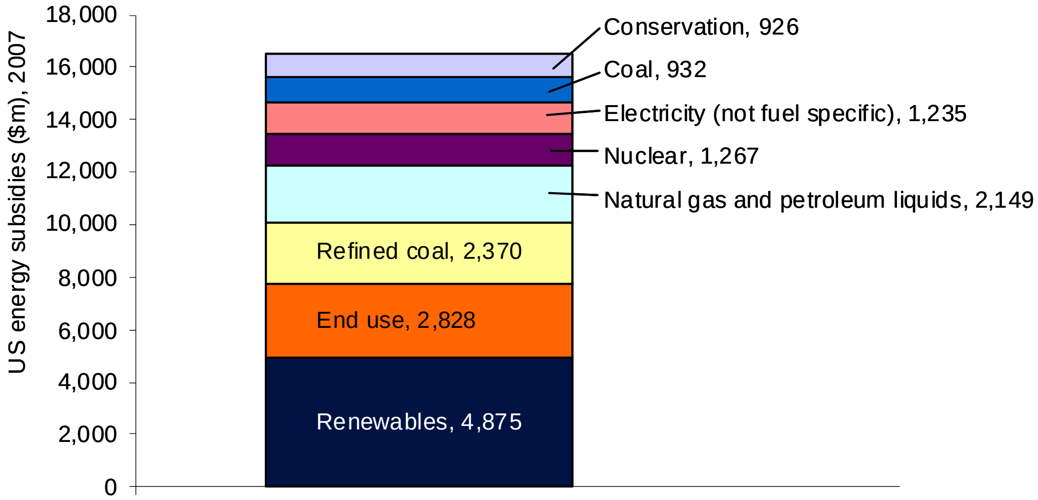
Subsidies of this sort are both economically and environmentally harmful because they encourage excessive consumption of energy resources. Their use is often a political tool, as can be seen in Russia, Iran and elsewhere but once established they become entrenched and extremely difficult to curtail. Against this, there may be valid social arguments for subsidizing the cost of energy to, for example, the very poor sections of a community, as can be found in India. Even so, in general such subsidies are likely to be harmful over the long term.

Table 6.32: US energy subsidies ($m), 2007

Beneficiary	Subsidy ($m)
Coal	932
Refined coal	2,370
Natural gas and petroleum liquids	2,149
Nuclear	1,267
Renewables	4,875
Electricity (not fuel specific)	1,235
End use	2,828
Conservation	926
Total	**16, 581**

Source: EIA[71] Business Insights Ltd

Figure 6.29: US energy subsidies ($m), 2007



Source: EIA Business Insights Ltd

The figures in Table 6.32 are all for non-OECD countries but other countries are not exempt. Often subsidies in OECD countries simply appear in a different form. Table 6.32 shows federal energy subsidies in the US in 2007 as determined by the US Energy Information Administration. These show total subsidies of $16.6bn spread broadly across the spectrum of fuel and generation types as well as some targeting end users and conservation.

In the light of the growing awareness of global warming and the part played by fossil fuels, fuel subsidies have been recognized as a serious international problem. In September 2009 the G20 group of countries agreed to phase out fuel subsidies for fuels responsible for production of CO_2 over the medium term, with a target date of 2020 for their elimination.

Tariff subsidies

A tariff subsidy is a subsidy that reduces the cost of electricity to a particular group of consumers. Such subsidies are common in the developing world where they are used, like fuel subsidies, to shield all or parts of a population from the full cost of electricity. Such subsidies are likely to make up part of the subsidy totals is the tables above but sometimes they can be independently identified. For example an IMF presentation showed that in 2005 the tariff subsidy in Kazakhstan, Tajikistan and Uzbekistan was over 10% of GDP and in Bulgaria and Georgia it was over 4%[72].

Such tariff subsidies often involve both state subsidy and cross-subsidy where industrial tariffs are artificially raised on order to fund a reduction in domestic tariffs. The danger inherent in such policies is clear. If electricity is subsidized then the consumer does not pay the cost of its production. In an extreme example of this, in Tajikistan in 2003 the tariff subsidy was 19% of GDP according to World Bank figures and the average tariff was only 25% of the cost of producing the electricity.

Such subsidies make it difficult for electricity companies to invest in new or modern capacity since the income from production is often less than production costs. It also forms a barrier preventing private sector involvement because there is little possibility of a return on investment.

Tariff subsidies in developing countries are usually broadly targeted. Others elsewhere can be much more precisely targeted. Renewable technologies benefit in some parts of the world from 'feed-in tariffs' which provide a pre-determined fixed sum for renewable electricity which is fed into the national grid. The tariff must be paid by the system operator or electricity marketing company and is normally set at such a level that it makes it economical for renewable generators to operate. This type of tariff has been successfully used in a number of countries in the EU to encourage the introduction of renewable generation. It is, in effect, a cross-subsidy since the additional cost paid for renewable generation must be recouped by raising the cost of electricity from other sources.

Other distorting mechanisms: quotas and taxes

There are distorting mechanisms, like feed-in tariffs, that attract a broad level of approval. Another such is the renewable quota, known as a Renewable Portfolio Standard in the US and the Renewable Obligation in the UK. These are used by governments as a means of increasing the use of renewable generation. In this case the use of renewable capacity is enforced by legislation which demands that generators or electricity resellers source a fixed proportion of their electricity from defined renewable technologies. (These definitions may be perverse, however, rejecting large hydro, for example, while including landfill methane-based generation.)

Quotas of this type are another distortion of the market since they force generators to build renewable generation whether it is seen to offer the most economical source of electricity of not. The overall effect is again like a cross-subsidy since any additional costs associated with the renewable generation must be recouped from the sale of electricity from conventional sources. In this case, however, it is the consumer who pays the subsidy.

A final factor which can have a significant effect on the real cost of electricity from a power generation project is tax. This can be important for levelized cost of electricity calculations but such calculations frequently ignore the effects of tax or make a general adjustment for its effect. Often, however, the effect of tax will influence different generating technologies differently. This needs to be taken into account specifically in order to make an accurate levelized cost assessment.

The effect of tax depends on the tax regime under which the company investing in a power plant is operating. In most industrialized countries there are two important tax concessions which will reduce costs. The first of these is expenses. These will include the cost of such things as fuel and maintenance and can often be offset against tax. This means that provided a plant is making a profit, these costs will be deducted from the taxable income. So if for example a company makes an outlay of €500 on maintenance under a regime where the rate of tax on profit is 20%, the net outlay will effectively be reduced by 20% to €400.

The second concession affects capital outlay. The latter will normally be offset against tax using some depreciation calculation. If a wind farm costs $20m and this capital outlay is considered to have become worthless in 10 years for tax purposes, the company which owns the wind farm can offset a part of that cost against tax each year until the whole $20m has been offset. In the first year, for example, it may be able to offset $2m which at a tax rate of 20% is equivalent to reducing the tax bill for that year by $400,000.

The overall effect of both these tax offsets is to reduce the net cost of electricity compared to that when tax is ignored. The capital offset allowance will be more significant for capital intensive projects than it will be for lower capital outlay schemes. This means that its omission could affect many renewable projects more significantly than for example, a relatively cheap combined cycle gas-turbine project by making the cost of electricity from the first seem higher than it actually is.

Chapter 7

The cost of power

Chapter 7 The cost of power

Introduction

In the preceding chapters we started by examining, in Chapter 2, the traditional methods used to attach a cost to generating capacity and power generation, the capital cost of generating plants and the levelized cost of electricity. These together still represent the most widely used yardsticks with which to compare different generating technologies for future capacity expansion and they will be used again below to compare current costs. The levelized cost model takes little account of risk and Chapter 3 looked at ways of introducing risk into the equation. Risk associated with fuel price volatility is probably the most important type of risk that needs to be considered but investment risk may play a key role too, particularly where new generating technologies are concerned. The introduction of risk and of the methods by which it can be ameliorated show how a liberalized electricity market is beginning to resemble a financial market and this analogy has encouraged the use of financial tools within the electricity sector. Among these, portfolio management techniques offer a particularly interesting method of determining the optimum mix of generating technologies for a given network.

Predicting the cost of electricity and of electricity plants is an incomplete science and its predictions should always be evaluated carefully. The only real yardstick against which the predictions can be compared is the historical cost of plants and power. These were examined in Chapter 4 along with the historical cost of fossil fuels and historical trends affecting the capital cost of power generating technologies. The past cannot be relied upon to predict what will happen in the future as the 2008-2009 financial crisis has shown, but much future behavior will be found to have happened before and lessons from history will always be valuable when exploring future trends.

One of the key issues facing the world today is that of environmental protection and the hazardous effects of industrial activity and these can be expected to have an ever increasing influence on the cost of electricity. Chapter 5 took a broad look at some environmental measures of power plant performance. Whereas the economic yardsticks of Chapter 2 indicate which technologies are the most cost effective, environmental analyses can show which are the most environmentally benign. Lifecycle analyses examined in Chapter 5 showed the clear difference that exists between renewable and fossil fuel technologies in this regard. CO_2 emissions are particularly relevant today and here renewable technologies have an obvious advantage. The chapter also looked at ways of attaching a cost to CO_2 emissions and what that cost is likely to be in the near future.

Finally, Chapter 6 looked at a range of other issues that can distort the cost of electricity relative to the open market price. There may be arguments for distorting the market price with subsidies and special tariffs but unless the real cost of a unit of a unit of electricity is known first, the effects of such measure and the degree to which they are successful in their aims will be impossible to gauge. However some distortions are so entrenched, particularly those relating to the environment, that in most cases today it is impossible to determine the total cost of a unit.

It will be clear from all this that determining the future cost of electricity from a proposed power generating project is far from simple. Even the traditional levelized cost calculation will yield different results from country to country as both capital and fuel costs change. In truth this calculation, even when carried out with great care, can only offer a ball-park figure for cost of electricity. And while factors such as risk and the effects of tax can be included to try and make it more accurate, the reliability of the results are almost impossible to judge.

This is further complicated by the environment in which investment decisions are made today. In the pre-liberalized world of electricity where monolithic vertically integrated utilities often ruled, the price of electricity to consumers was usually controlled and predictable. During this era investments were often determined politically as well as economically, based at best on an evaluation of the generating mix likely to produce the most stable as well as the cheapest future supply. When prices are stable the calculation of returns on an investment can be made with confidence, provided the initial calculation of lifetime output from a power plant is reasonably accurate. In most cases today price stability is no longer a fact that can be taken for granted. The price of electricity is determined by a market and operating markets across the globe have shown that large and unexpected prices swings, both up and down, are now a fact that must be taken into account.

The future of the liberalized electricity market

The truth is, as has been noted several times already within this report, the electricity market is becoming increasingly like a financial market. This can be seen in the growth of instruments such as electricity futures which allow speculative future contracts for electricity to be struck and in the introduction of a variety of other hedging instruments such as those discussed in Chapter 3. The problem with markets of this type today is that investments are being made more and more on the basis of perceived short-term gain and less on the basis of future long term stability. This may eventually lead to a political backlash against the electricity market model as currently enacted, in the same way as there is a political backlash today against financial market practices. Governments and policy makers may seek to take back at least some control over the operation and structure of a market which increasingly appears unable to deliver security, stability or low cost.

Where markets fail to provide stability, governments must try because the health of their economies depend on stable electricity prices. But since they can no longer influence a liberalized market directly, they must do indirectly. Renewable quotas, feed-in tariffs and carbon taxation are some of the ways of sending economic signals that shift the way the market operates. And there is increasing pressure on governments to fund research into new and advanced power generation technologies and then underwrite projects demonstrating these technologies because on its own, industry (or probably, more specifically, company shareholders) cannot see the short-term gains to be made from such investments. Astute investors will be looking at these trends as well as the headline market trends in order to determine future directions.

Other factors affect the investment climate too. There is an increasing body of opinion that electricity prices in market-based systems follow a boom-bust cycle similar to those seen in financial markets[73]. When electricity prices fall, return on investment falls and there is no incentive to invest in new capacity. However as the market tightens and demand begins to outstrip capacity, then prices rise and returns on investment rise. Electricity companies may, therefore, try to predict these price rises and time their investments to catch the price peak.

Such factors may be considered a natural consequence of an open market. Equally they may be taken as signs that the model is wrong and should be abandoned. Today such as suggestion is no longer unthinkable. An open electricity market may appear to be the modern solution to the delivery of electricity but its foundations are in part based on dogma, the dogma of market capitalism. It has become easy to ignore the fact that electricity companies are utility companies, utility companies that are supplying a product that individuals and companies cannot do without, supplying a commodity that forms one of the foundations of the other open market. Not only that, electricity is far from a natural competitive market. Shoehorning the electricity supply industry into a structure suitable to permit an open market to operate has introduced an alarming array of compromises. There are indications today that this structure may not be capable of performing the job required of it.

Electricity in this respect is no different to the banking industry. That has singularly failed to provide the service society demands of it in return for the market freedoms it has been granted. In the case of banking, tough legislation is going to be the solution. There is no reason to suppose that the electricity industry will be exempt if it cannot provide the service society demands of it. The debate has already been opened in the UK, the flagship of electricity sector liberalization. This may prove a key area of discussion and potentially of change over the next decade. Investors should be aware of this potential.

Market trends

While the nature of the electricity market may have changed the fundamentals of the industry, the hardware, remains the same. Here change is slow, generally predictable and easier to measure. The same fundamental technologies - nuclear, fossil fuel-based and renewables - are still the means of generating electricity and over the long term it will remain the relative performance of these that will determine the future of the electricity industry. Are there any clear trends to be discerned here?

The past decade has seen several significant trends. The most important is the widespread introduction of renewable technologies. Their advance has been built mainly on the back of legislation and regulation to encourage the use of emission-free technologies and shift away from fossil fuel-based generation. Bald global generation mix figures may suggest not much has changed but the rapid growth of global wind capacity and latterly of solar capacity are clear indications that a shift has begun.

The advance of renewable technologies, particularly wind, have been accompanied by a fall in costs and improvements in both reliability and performance. Both have encouraged investment in wind farms. In some contexts wind appears now to be competitive with conventional fossil fuel generation but how much one reads into figures suggesting this depends on ones faith in the economic modeling which, as we have seen carries a wide margin of uncertainty.

The other major trend discernible during the past decade has been the volatility and steep rise in the cost of fossil fuels, particularly natural gas. This has led to steep increases in electricity prices in some markets, to questions about energy security and to a somewhat broader recognition of the risks associated with price volatility. In spite of this natural gas has remained a favored source of new generation but at least its use has been queried.

These trends were already becoming clear when the last Cost of Power report was published in 2008. Since then there have been two important changes. The financial crisis that in early 2008 appeared to be a banking crisis was by 2010 a massive global economic depression. This has affected the availability of finance for new power projects, hitting some major renewable generation projects. Power generation remains a relatively safe investment but investors are more questioning about each project. In this climate renewable generation appears to need clear incentives to succeed.

A second change, the importance of which is yet to become fully clear, is the widespread extraction of natural gas from shales. This has resulted in an expansion in US gas supply that was not expected two years ago. Against this backdrop and a predicted period of relatively low gas prices, the natural gas industry and its partners are heavily promoting gas-fired power generation as part of the solution to global warming. How this will develop, and whether extraction from shales will become common in other parts of the world are unanswered questions today but if the trend develops it will have consequences for other types of generation.

Levelized cost trends

What of the relative cost of power from different technologies today? Sets of figures from two sources, the US Energy Information Administration (US EIA) and Lazard, were presented in Chapter 2. Further figures, this time from the California Energy Commission (CEC) and from Parsons Brinckerhoff are presented below.

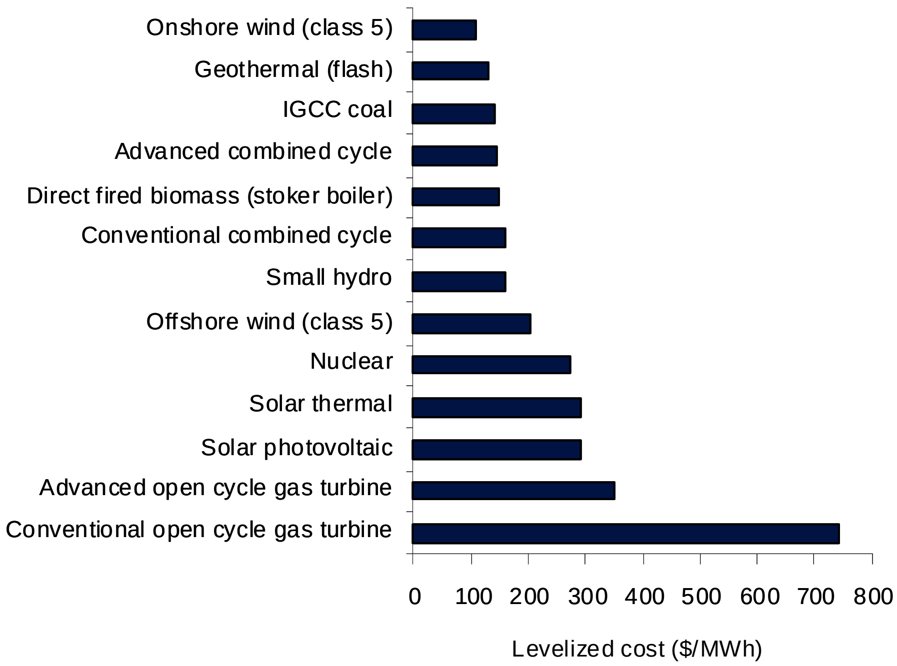
Table 7.33 shows figures produced by the CEC taken from levelized cost exercises the commission carried out in 2003, 2007 and 2009. The figures represent costs for investor owned utilities. Merchant plant and municipal utilities would have different costs due primarily to their differing abilities to borrow on the financial markets. The figures for 2009 indicate that in California the least new cost source of electricity is renewable with onshore wind in a class 5 wind regime able to provide power for \$70/MWh. Geothermal power (\$89/MWh) and small hydropower (\$96/MWh) are also both below \$100/MWh as, curiously, is integrated gasification combined cycle (IGCC) with a levelized cost of \$98/MWh. A conventional combined cycle plant will generate power for \$115/MWh while an advanced combined cycle plant is more competitive, with a generation cost of \$106/MWh, similar to a biomass plant. Meanwhile solar generation is much more expensive, with solar thermal generation costs \$238/MWh and solar photovoltaic costs $279/MWh. Nuclear power is not included in Table 7.33 but the figures in Table 7.35, below, suggest that nuclear power in California is expected to be similar in cost to solar power.

Table 7.33: California Energy Commission levelized cost ($/MWh)

	2003	2007	2009
IGCC - coal	-	106	98
Conventional combined cycle	52	95	115
Advanced combined cycle	-	89	106
Conventional open cycle gas turbine	157	469	615
Advanced open cycle gas turbine	-	202	281
Direct fired biomass (stoker boiler)	-	102	106
Geothermal (flash)	45	62	89
Small hydro	60	118	96
Solar thermal	220	281	238
Solar photovoltaic	-	696	279
Onshore wind (class 5)	49	67	70

Source: California Energy Commission[74] Business Insights Ltd

Figure 7.30: California Energy Commission levelized cost ($/MWh), 2009



Source: California Energy Commission Business Insights Ltd

When reading these figures it is important to remember that wind, biomass and small hydropower are capable of supplying only limited quantities of power over the short to medium term. Additionally, as wind capacity is added all the best wind sites will be used and exploitation of less suitable sites is likely to be more expensive. Solar power has to potential to supply very large quantities of power, particularly in a region like California with extensive deserts but remains extremely expensive today. This leaves fossil fuel plants which can provide large additional tranches of generating capacity but which are subject to fuel price risk.

Table 7.33 also demonstrates some interesting trends. Cost of power from all the established technologies have risen between 2003 and 2009 due to commodity and labor price increases but not by the same amounts. The cost of power from a conventional combined cycle plant has risen by 121%, while from a geothermal plant it has risen by 98%, and from a small hydro plant 60%. Among the developing renewables, the cost of wind power has risen by 43% and of a solar thermal power plant by 8%. Solar photovoltaic costs have probably fallen but there is no figure from 2003 to confirm this.

A different perspective on costs is provided by the figures in Table 7.34 which are for the UK and were published in 2010 by Parson Brinckerhoff. Here we find that contrary to the situation in California, the cheapest new source of power is a nuclear power plant with a levelized cost of £50-£90/MWh. The most competitive fossil fuel plant is a combined cycle plant burning natural gas with a levelized cost of £50-£110/MWh while the most cost effective renewable source is biomass with a levelized cost of £60-£120/MWh.

The table contains estimates for three fossil fuel plants with carbon capture and storage (CCS). The most economical is a combined cycle plant with CCS with a levelized cost of £60-£140/MWh which at the lower end is not massively higher than for the plant without CCS. The two coal plants with CCS, a pulverised coal plant and an IGCC plant, have estimated costs of £100-£160/MWh and £100-£159/MWh, essentially identical.

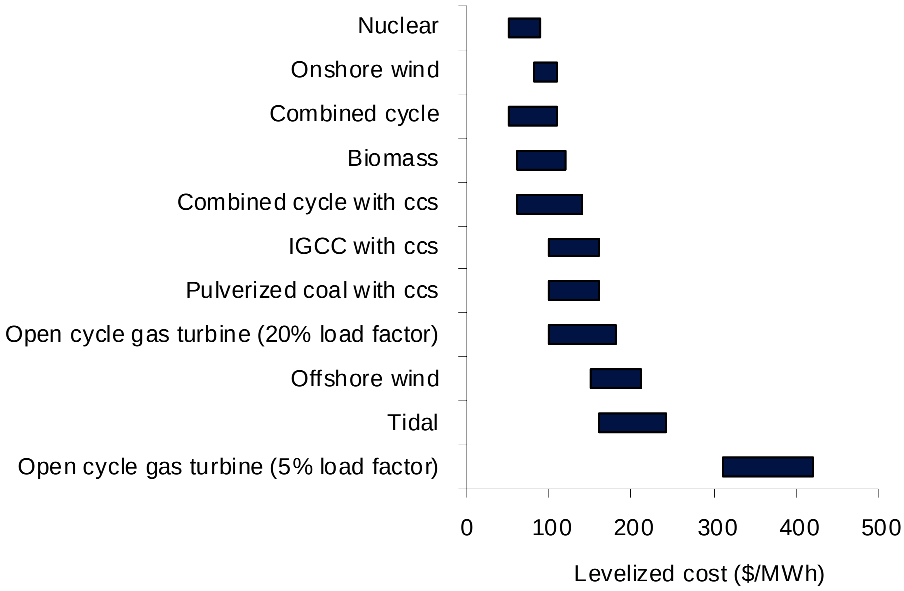
The UK's most valuable renewable sources are wind and marine. Onshore wind, on this estimate, has a levelized generation cost of £80-£110/MWh which while more expensive at the lower end than combined cycle, is still cheap enough to offer a valuable hedge against gas price volatility. Offshore wind, the larger UK resource, is significantly more expensive at £150-£210/MWh. Meanwhile the cost of electricity from tidal power is put at £160-£240/MWh.

Table 7.34: UK levelized cost estimates[75] (£/MWh), 2010

	Levelized cost (£/MWh)
Pulverized coal with carbon capture and storage	100-160
IGCC with carbon capture and storage	100-159
Combined cycle	50-110
Combined cycle with carbon capture and storage	60-140
Open cycle gas turbine (20% load factor)	100-180
Open cycle gas turbine (5% load factor)	310-420
Nuclear	50-90
Biomass	60-120
Onshore wind	80-110
Offshore wind	150-210
Tidal	160-240

Source: Parsons Brinckerhoff[76] Business Insights Ltd

Figure 7.31: UK levelized cost estimates (£/MWh), 2010



Source: Parsons Brinckerhoff

Business Insights Ltd

Against these two sets of figures there are also those in Table 2.5 from the US EIA. These are all for new power plants entering service in 2016. Here it was found that a combined cycle gas turbine power plant was, by a significant margin, the cheapest new source of power for entry into service in 2016 with a levelized cost of $83/MWh for a conventional plant and $79/MWh for an advanced plant. A conventional coal-fired plant was expected to generate for around $100/MWh and an advanced coal plant for $111/MWh. Of the options for fossil-fuel generation with CCS, the most economical was a combined cycle plant with CCS at $113/MW while an advanced coal plant with CCS has a levelized cost of $129/MWh. Meanwhile an advanced nuclear plant could provide electricity in 2016 for $119/MWh.

Of the renewable technologies in Table 2.5, biomass offered the cheapest power at $110/MWh followed by geothermal ($115/MWh) and hydropower ($120/MWh). Onshore wind had an average cost of $149/MWh, offshore wind $191/MWh, solar thermal $257/MWh and solar photovoltaic $396/MWh. It is worth repeating what was noted in Chapter 2 regarding these wind figures that the onshore wind costs are an average across the US and the cheapest cost was $91/MWh while the most expensive was $271/MWh.

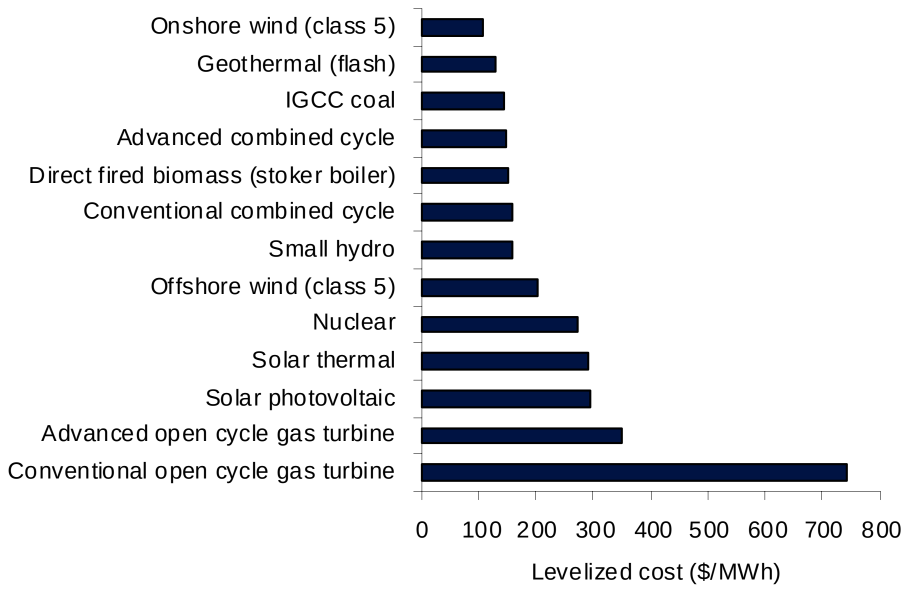
A final set of figures are presented in Table 7.35. These, from the California Energy Commission, are predictions for plants entering service in 2018. As with the previous CEC figures, onshore wind remains the cheapest source of electricity with an estimated levelized cost in 2018 of $108/MWh. Geothermal power is the second most cost effective at $128/MWh. However the third most cost effective is an IGCC coal plant at $143/MWh, followed by an advanced combined cycle plant at $147/MWh and a conventional combined cycle plant at $149/MWh. In California, nuclear power is expected to be much more expensive at $273/MWh, similar in cost to the two solar technologies, solar thermal at $289/MWh and solar photovoltaic at $295/MWh.

Table 7.35: Levelized cost predictions for plants entering service in 2018 ($/MWh)

	Levelized cost ($/MWh)
IGCC coal	143
Conventional combined cycle	159
Advanced combined cycle	147
Conventional open cycle gas turbine	744
Advanced open cycle gas turbine	351
Nuclear	273
Direct fired biomass (stoker boiler)	149
Geothermal (flash)	128
Small hydro	160
Solar thermal	289
Solar photovoltaic	295
Onshore wind (class 5)	108
Offshore wind (class 5)	203

Source: California Energy Commission[77] Business Insights Ltd

Figure 7.32: Levelized cost predictions for plants entering service in 2018 ($/MWh)



Source: California Energy Commission　　Business Insights Ltd

What conclusions can be drawn from all these analyses? In the first place most suggest that the conventional fossil fuel sources, coal and natural gas, continue to be among the most competitive sources of electric power for large scale power generation. Even when carbon capture and storage is included, the cost of electricity from these power stations is likely to remain among the most economical available. Gas generation is vulnerable to fuel price volatility but if natural gas prices stabilize over the short to medium term then gas is likely to remain a favored source of new generating capacity. However if price volatility and steep price rises return, then gas generation may suffer.

Coal is the major source of base load power in many parts of the world and its position is not likely to change rapidly. What is likely to change is the use of CCS. Demonstration projects should begin to come on line over the next five years and this will allow the technology and its costs to be evaluated. Current estimates indicate that CCS will make coal-fired generation expensive, but not prohibitively so.

The position of nuclear power is not so clear. The UK figures in Table 7.34 make it the most economical source but it is notably more expensive than electricity from natural gas or coal fired plants in all the US estimates. When CCS is introduced, nuclear power becomes relatively more competitive. However nuclear power carries a large investment risk because of the high capital cost of plants and continuing uncertainty about the performance and safety of advanced nuclear plant designs. The nuclear renaissance that has been anticipated for most of the past decade has yet to appear.

Renewable generation should therefore offer the main alternative to fossil-fuel generation. Over the medium term wind power appears the cheapest and most accessible source, with onshore wind power competitive or close to competitive in both the US and the UK. The US EIA figures from Table 2.5 quoted again above, highlight a potential problem with wind generation, the exhaustion of good sites. The high average cost of wind in the US in 2016 is partly a result of all the best wind sites having been exploited. This is likely to prove a problem globally as wind capacity expands and may provide a natural limit in overall capacity. Offshore wind has the potential to provide large quantities of power where it is available but the cost will remain significantly higher than onshore wind.

Other renewable sources such as biomass, geothermal and hydropower are limited in the overall capacity they can provide although each will have a significant role in future power generation mixes. Marine technologies are beginning to attract investment too but it may be another decade before they are a commercially viable option. Over the long term, the most important renewable source is likely to be solar power. This has the potential to provide massive quantities of power but today the price is too high to make it competitive without incentives.

The past decade has been characterized by fossil fuel prices rises and price volatility, particularly in the natural gas market but also for coal accompanied by a greater willingness to invest in renewable sources of electricity. The global depression has caused a slump in fossil fuel prices, shifting the economic balance back towards fossil fuel generation which, anyway, provides the bulk of electricity today.

If fossil fuel prices remain depressed, then renewable investment may slow. However there were indications in the second quarter of 2010 that oil prices were surging again making the outlook uncertain. The greatest uncertainty, however, is attached to the introduction of carbon capture and storage for fossil fuel plants. Most predictions suggest this should become mandatory for new coal and gas plants in the developed world by 2020. Given the absence of global agreement and the absence of any demonstration plants to prove large scale use of the technology, it appears increasingly possible that this deadline will slip.

Against that, there are moves to fund demonstration projects and political agreement on global warming may be close. Even if the deadline does slip, the introduction of CCS cannot be far away. It would be prudent to assume this for any medium term capacity planning.

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