PB POWER

Summary Report

Powering the nation

A review of the costs of generating electricity

March 2006

Introduction

In April 2004, The Royal Academy of Engineering published its report 'The Costs of Generating Electricity'. The Academy felt that 'in order to make sensible decisions about energy policy for the UK, policy makers need to be able to compare the costs and benefits of different types of electricity generating technologies on a like-for-like basis'.

PB Power was commissioned to undertake the underlying analytical work on technology costs, fuel prices, and other costs associated with the production of electrical energy from a wide range of electricity generating technologies. The terms of reference set by the Academy for the work were to prepare an analysis based on:

- Simple, soundly based indicators of cost performance for a range of different technologies and fuels;
- A focus on 'bankable' projects over the next 15-20 years which were compliant with existing and future environmental legislation;
- The impact of intermittency and carbon dioxide emissions;
- The cost of the plant itself (EPC cost) net of soft costs eg developer costs, financing charges etc.

Since the publication of that report, significant changes have occurred in relation to electricity production in the UK:

- Gas prices have risen considerably and long-term security of supply has become a major issue;
- There is increased interest in the so-called 'advanced' coal technologies;
- The rate of growth of renewables has continued to fall short of target;
- Nuclear power is now under significant scrutiny.

In January 2006, the Government launched its Energy Review to assess the progress made against the goals of the 2003 Energy White Paper and identify the options for further steps to achieve them.

A wide-ranging consultation with interested parties is now under way to inform the Review with the outcome to be presented to the Prime Minister in early summer 2006.

As a contribution to the Review, PB Power has re-examined the work it carried out for The Royal Academy of Engineering in 2004 and updated some of the assumptions it made at that time on capital costs of generating plant, fuel costs and discount rates.

This report has focused on the cost of generating electricity. While this is an important consideration in the choice of power generation technology it should be recognised that wider issues also contribute to the technology employed. This may, for example, include technology complementation, security of fuel supplies, and social and environmental factors.

The results of this new study are presented in summary form in this document; the basis on which the presented analysis has been conducted is set out in some detail and the results presented in pictorial form. A full version of the report, containing a comprehensive description of the methodology adopted and the rationale for the underlying assumptions, is available at a cost of £250 from www.pbworld.com/power.

Electricity production technologies and the generation mix

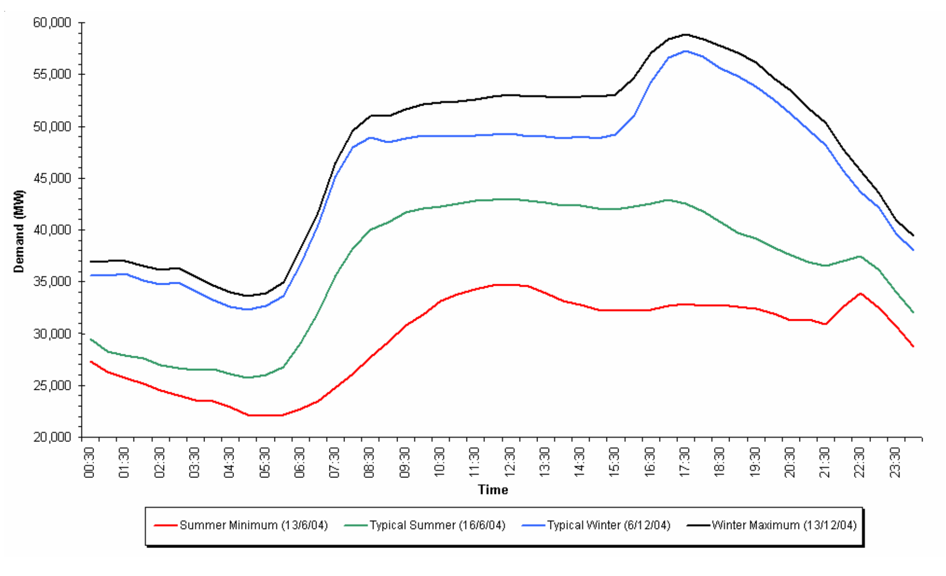
The fundamental difficulty with balancing the supply of, and demand for, electricity derives from the physical nature of electricity and the fact that it is presently not commercially viable to store it on a sufficient scale to be of use to electricity utilities. In this regard, electricity is a unique commodity in that the rate of its production must balance the rate at which it is consumed at all times if the electricity system is to maintain stability.

Demand for electricity is not constant and fluctuations in load occur:

- At different times of the day to reflect the pattern of working hours and the effects of electric lighting, cooking, heating etc;
- On different days of the week to reflect the patterns of domestic, industrial and commercial activity on weekdays, weekends and holidays; and
- In different months of the year, often reflecting different climatic conditions.

The range of diurnal demand variation during the year is illustrated by the graph below[1]

Figure 1 - GB Summer and Winter Daily Demand Profiles in 2004/2005

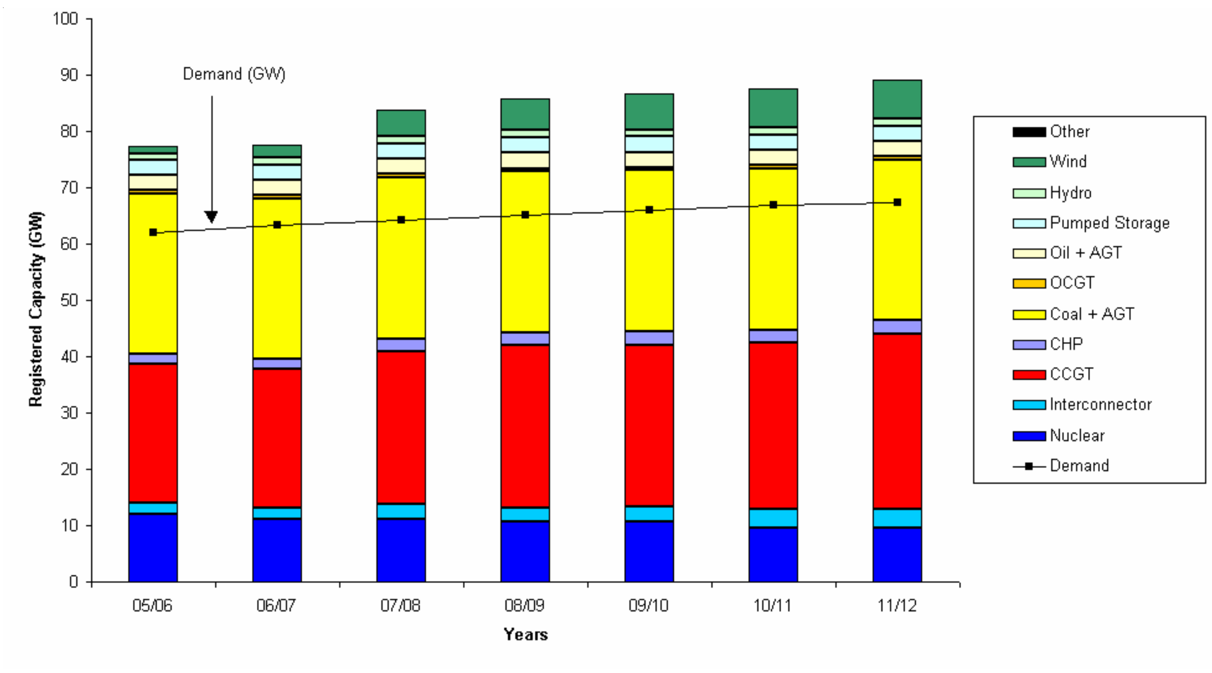


[1] NGC Seven Year Statement, May 2005, Figure 2.2.

In order to provide a high quality supply of electricity, sufficient generation plant ('generation capacity') must be constructed to meet demand at its highest point. By implication, this means that there will be times of the day and year when demand is not at its highest point and generation capacity is standing idle, ie not all generation capacity is fully utilised all of the time.

The characteristics of the various generation technologies (fuel type, thermal efficiency, capital costs) mean that they will naturally operate to provide electricity at different times of day and year. The combination of the commercial pressures in the market and the system security requirements of the System Operator means that there is a range of types of generation technology forming the grid mix at any given point in time. The way in which this grid mix in the GB market is expected to change in the near future is illustrated below[2]:

Figure 2 - Existing and Planned Transmission Contracted Generation



[2] NGC, Seven Year Statement, May 2005, Figure 3.2.

The electricity market in Great Britain

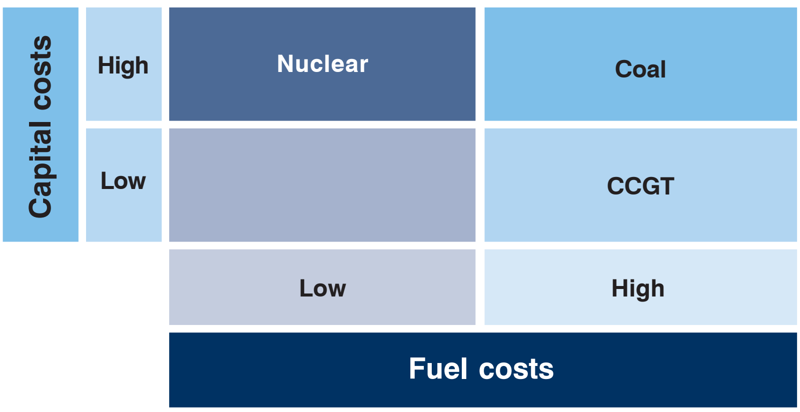
Within the Great Britain (GB) electricity market, the generators contract bi-laterally with electricity suppliers or large-demand customers for the sale of the electricity that they produce. This process is competitive and can be carried out either directly between the market participants or through brokerages or registered power exchanges. Bi-lateral contracts for electricity can specify the provision of any 'shape' of output that the parties agree on - for example this could be base-load, base-load with mid-day peaks, or peaks only. Electricity is traded on a half-hourly basis.

There is a deadline set at one hour[3] before the start of each half-hour settlement period for the market participants to conclude all bi-lateral transactions relating to that settlement period. All volumes of electricity that have been sold bi-laterally for each half-hour period are notified to the Market Operator[4] ahead of real time. The onus is then on the market participants to ensure that they schedule their generation or demand to match their notified contracted electricity volume, ie they self-dispatch their plant to meet their contractual obligations.

Where a market participant does not match his actual and notified volumes, he is subject to an imbalance charge that reflects the costs of the System Operator actions to correct the system balance caused by this mismatch. This process is done for each half-hour settlement period and is known as 'imbalance settlement'.

The mechanics of the GB market are such that there is no explicit capacity signal to cover the fixed costs of new entrant power generation capacity. The recovery of their fixed costs needs to be done on the basis of bi-lateral contracts or by taking the risk that wholesale electricity market prices for fuel and electricity will maintain their relative competitiveness with the existing generation capacity, allowing the plant owners to recover their fixed costs and secure their return on investment (Figure 3).

Figure 3 - Qualitative comparison of 'main' generation technologies



[3] This is known as the Gate Closure time.
[4] The Market Operator is Elexon - a wholly owned subsidiary of the National Grid Company.

This exposure to forward fuel and electricity price uncertainties for new entrant plants means that investors will tend to invest in those projects that have the lowest fixed cost overhead and the highest generation efficiency. The technology of choice in the last ten years or so in the UK has been CCGT plant. The combination of its low capital cost, rapid construction time and high thermal efficiency meant that it presented the lowest risk for investors.

CCGT plant, however, is ideally suited to base-load operation. Other generation capacity is required to provide electricity to cover the short-term intra-day electricity demand variations – typically between 40% and 75%. This 'mid-merit' plant is presently provided by older generation plant that has recovered its fixed costs but which is not able to compete on a marginal cost basis with the base-load plant. This mid-merit capacity is provided by the older coal plant in the GB market.

The peak electricity demand is provided by plant that is already operating on the system that can ramp-up quickly, or from specific 'peaking' generation capacity that is called to run by the System Operator at short notice. This capacity tends to be open-cycle gas turbines or hydro-electric generation plant[5].

Future grid mix

The future grid mix will be dependent on, amongst other things, investment decisions made now. The present high fuel prices for gas-fired plant means that the efficiency advantage of CCGT plant has been eroded. CCGT plant is still, however, regarded as the least capital intensive of the generation technologies and it is for this reason that there is an expectation in the market that CCGT plant will continue to be the technology of choice for new entrant generation capacity.

[5] Hydro-electric generation is 'energy constrained' due to the finite amount of water available for it to use for generation.

Approach and Sensitivities

In this section we briefly describe the approach adopted and the key sensitivities that have been analysed in this review.

We have utilised costs and prices apparent in the power generation market since 2004 for plant costs, operation and maintenance, and carbon allowances set in the National Allocation Plan.

The carbon and fuel pricing has been referenced to recent DTI long-term forecasts[6].

The costs of electricity reported in this review are intended to provide an indication of the relative competitiveness of the different technology types. It is not intended as a prediction of any future grid mix nor does it attempt to project forward prices for fuel.

The analysis has been carried out in real terms with 2006 being the base year. All construction for projects is assumed to commence in 2006.

[6] 'UK Energy and CO_2 Emissions Projections - Updated Projections to 2020', DTI, February 2006

Approach

We have used a discounted operational cash flow model to calculate the lifetime costs of generation from the various technologies on a long run marginal cost basis. This is a widely used method for the analysis of power system costs. The comparisons made are cost comparisons that exclude any associated revenues (such as ROCs or LECs) that may be received by the generator.

The capital investment in the generation technology is assumed to be financed 'on balance sheet' by market participants which, therefore, removes the need for sensitivities relating to project/ debt equity structures.

The data used within this report is based on information owned by PB Power through the company's involvement in the power generation industry, acting either for project developers, project financiers or project operators. The data relates to UK projects and has been referenced, wherever possible, to independent external sources in the public domain.

The specific base-case assumptions for each technology are detailed in the Sensitivities section.

The calculations do not take into account taxation or capital allowances and are intended to provide an indication of the costs of production of electricity from the different technologies at the point of plant connection to the electricity grid.

Whilst the point of connection of a power generator to the electricity network does affect the total costs of providing that power to the electricity market, the costs that arise due to transmission and distribution losses and the 'use of system' charging applied by the Transmission or Distribution Network Operators and the System Operator are not included in the costs we have tabulated. We believe that this allows for a fair comparison between technology types.

We also exclude any revenues associated with support mechanisms such as the Renewable Obligation and the Climate Change Levy exemption as these are subsidies designed to assist the development of sub-commercial or immature technologies.

Sensitivities

Discount rate

Recognising that the electricity market has restructured significantly with the introduction of BETTA in April 2005 and the continued consolidation of independent power generation plant within vertically integrated companies, we have increased the base discount rate assumption of 7.5% used in our earlier study.

This report has used a base discount rate of 10% that we believe more closely reflects the balance sheet expectations of the vertically integrated utilities.

Within any market there are risks for investors that are dependent on the technology, regulatory/ legislative uncertainty, and input pricing over the project life. The assumed base discount rate recognises such market risks to a degree. We have, however, carried out a sensitivity analysis using discount rates of 7.5% and 12.5% to provide an indication of the effect of changes in the perception of potential investors.

The discount rate appropriate to a specific project is dependent on the maturity of the technology, the residual risks within the project from un-contracted output or fuel supplies, and certain conditions relating to the site itself (ground conditions, grid access etc). This means that whilst generic assumptions can be made for a given technology type, these can only provide an indication of the relative costs of different technologies at a given point in time.

Capital costs

These are the engineer, procure, construct (EPC) costs of building a typical plant within each generic technology type. The capital cost is sensitive to the following factors:

- Site-specific requirements relating to supporting infrastructure;
- The duration of construction of the project (this affects the interest on capital incurred during the construction period);
- Price variations due to equipment supply and demand in the market at any given time; and
- Development, financing and legal fees (project 'soft costs').

There is no 'right' answer for the cost of a given technology, rather the costs will lie within a range that is representative of what can be expected in a typical competitive tendering process at a given point in time. The capital costs used within this review have been based on the information available to PB Power through its involvement in power generation projects globally, with specific emphasis on UK activities. This internal database of specific 'average' capital costs has been referenced to external independent reports on capital costs wherever possible to corroborate the assumptions used in the analysis.

A capital cost sensitivity has been carried out that reflects market expectations of the range of capital cost outcomes for each technology in the present market. The sensitivity inputs used are summarised in Table 1 overleaf.

Table 1 - Summary of capital cost sensitivities

Technology	Specific capital cost (£/kW)	Market expectations	
		Low	High
Coal PF	£687/kW	£618/kW	£860/kW
Coal CFBC	£611/kW	£550/kW	£765/kW
Biomass BFBC	£1,744/kW	£1,570/kW	£2,000/kW
Coal IGCC	£1,000/kW	£800/kW	£1,250/kW[7]
Gas OCGT	£366/kW	£330/kW	£410/kW
Gas CCGT	£340/kW	£275/kW	£375/kW
Wind (onshore)[8]	£824/kW	£596/kW	£1,070/kW
Wind (offshore)[8]	£1,236/kW	£892/kW	£1,375/kW
Wave[9]	£2,850/kW	n/a[10]	n/a
Tidal[11]	£2,200/kW	n/a	n/a
Nuclear[12]	£1,050/kW	£1,000/kW[13]	£1,200/kW

7 Mitsui Babcock, 'Clean Coal and the Energy Review', February 2006, p14.
8 'Nuclear Suddenly the Competitor to Beat', WindPower Monthly, January 2006.
9 Assumes a near-shore or shoreline oscillating water column plant. Mid point of the values on pp13 and 14 of 'Future Marine Energy', Carbon Trust, 2006.
10 Capital cost sensitivity not undertaken for wave or tidal due to wide range and high value indicating the early stages of development of the technology.
11 Mid point of the values on pp13 and 14 of 'Future Marine Energy', Carbon Trust, 2006.
12 Capital costs are based on PB Power dialogue with equipment manufacturers for EPC supply of new plant. The central value used in this report represents the upper end of the cost expectations of manufacturers and is therefore regarded as being a prudent value.
13 Derived from lower expectations of delivered nuclear costs. High limit represents a 15% uncertainty for cost outturn.

Fuel costs

There have been significant movements in fuel prices in the last two years. This trend is summarised in Table 2.

Table 2 - Recent movements in fuel pricing

Pricing date	Electricity[14] (£/MWh)	Coal[15] ($/tonne)	Gas[16] (p/therm)	Nuclear[17] (£/MWh)
March 2004	21.25	70.00	24.25	4.60
March 2006	50.83	61.00	55.18	4.60

- **Gas**: The movement in market pricing for gas has been significant in the last two years. The impact that this has had on the viability of gas-fuelled power plant is significant. The annual contract prices for gas in the gas year as at 2 March 2006 were in the region of 57p/therm and this value is seen to be holding relatively steady at 55p/therm out to summer 2008[18]. There is a body of opinion, however, that sees longer term pricing reverting back towards the levels of two years ago. To reflect this longer term view we have referenced our gas pricing to the recently published DTI[19] High, Higher Central and Lower Central price tracks. These have been escalated into 2006 real values for this study.
- **Coal**: The present typical delivered price in the UK is in the region of £1.40/GJ[20]. There have been movements in the coal price over the last two years. These, however, have largely been attributed to a shortage of shipping capacity pushing up the transportation proportion of coal costs. This appears to have abated somewhat and prices have reverted to the levels seen in early 2004 – around the $60/tonne mark. We have used the DTI published coal price tracks[21] as a reference for the required long-term coal pricing, taking the Central price track as the base case for this study. The DTI prices have been escalated to 2006 real prices.
- **Nuclear**: nuclear fuel costs are well understood. Most studies propose a fuel cost of about £4/MWh. We note that there is a separate debate in the industry about the sustainability of uranium supply and resultant prices, but the fuel cost component of the total cost of generation is relatively small. A 10% increase on input uranium prices results in a variation in electricity generation cost of just 0.2%. In addition to the front-end fuel preparation costs there is a potential range of costs associated with the back-end waste processing and disposal costs. A recent study in the USA[22] estimated that fuel waste disposal costs would be covered by a charge of 0.1 cent per kWh equivalent to 0.06 pence per kWh. This would therefore bring the total fuel costs to 0.46 pence per kWh. We have used this latter figure in our analysis.

[14] Electricity pricing: Annual April 2004 Contract reported in the Heren 'Industrial and Commercial Energy Snapshot', March 2004; Annual from March 2006 Heren 'European Daily Electricity Markets' report, 3 March 2006.
[15] Coal pricing from Platts 'Energy Economist', March 2006.
[16] Gas pricing: Gas Year 2004 from Heren 'Industrial and Commercial Energy Snapshot', March 2004; Gas Annual 2006 from Heren 'European Daily Electricity Markets' report, 2 March 2006.
[17] World Nuclear Association (£4/MWh) and NEI Nuclear Engineering Overview, 27 February 2006 (additional £0.6/MWh for waste treatment and disposal).
[18] Heren 'European Daily Electricity Markets' report, 2 March 2006, Average of Winter 07 and Summer 08 gas prices.
[19] DTI, 'UK Energy and CO_2 Emissions Projections - Updated Projections to 2020', February 2006, p17.
[20] Platts 'Energy Economist', March 2006; European CIF $60/mt.
[21] DTI, 'UK Energy and CO_2 Emissions Projections - Updated Projections to 2020', February 2006, p18.
[22] NEI Nuclear Engineering Overview, 27/2/2006.

- **Biomass**: biomass fuel costs are based on PB Power's involvement in the development and review of biomass projects and those reported in the RCEP Biomass Report[23] and by the DEFRA Biomass Task Force[24]. The fuels that are used have varying water contents and the pricing is therefore quoted on a standardised basis – oven dried tonnes (odt) – to aid comparison of fuel prices. The fuel pricing for biomass varies widely, with forestry residues falling in the range £15-£35/odt and chipped coppice/round wood in the range £40-£80/odt. For the purposes of this report we have assumed the biomass is sourced from forestry residues with a base price of £25/odt. A low sensitivity of £20/odt to reflect potential reductions in delivered forestry residue prices has been used; a high sensitivity of £60/odt has been used to provide an indication of the costs associated with coppice fuel.

Standby energy

This represents the costs incurred by a generator in replacing energy he is contracted to supply but which he fails to supply because of a forced outage of his power plant.

It is distinct from the costs associated with the integration of variable output plant such as wind generation.

This element of the costs is intended to provide an indication of the extent to which technical reliability of the various plant types contributes to their overall costs of generation. This technical reliability of each generation technology is based on calculations of typical forced outage rates.

When a generator fails to produce electricity due to forced outage, he will need to purchase replacement energy for his lost output in order to meet his contractual obligations. The cost of this replacement energy is assumed to come from generation plant that is already operating on the system but which has the capability to provide additional energy at short notice. In the context of system security this would usually be classed as 'spinning reserve'. Within the energy balancing mechanism in the GB market, however, the first call for replacement power is to other participants, who are running below maximum capacity, through direct trading. The balancing mechanism is a last resort for participants due to its relative price uncertainty and volatility.

The analysis takes account of this forced outage rate by the inclusion of the cost incurred by the generator buying his lost output from a reserve generator. The reserve generator is assumed to be coal plant operating at the margin and two-shifting within the GB market. This operational characteristic of the present electricity market is evidenced in the data from the system plant operation between March 2004 and February 2005[25]

The plant cost assumptions relating to the provision of standby energy are those used in the analysis for coal PF plant.

[23] Royal Commission on Environmental Pollution, 2004, 'Biomass as a Renewable Energy Source', Section 4.9.
[24] DEFRA Biomass Task Force Report to Government, October 2005.
[25] Half-hourly data provided by Elexon for the England and Wales electricity market.

Carbon emissions

The EU Emissions Trading Scheme (EU ETS) has been operational for just over a year and the price of carbon is now visible in the market albeit across relatively short timescales. This has removed an element of the uncertainty surrounding carbon pricing that existed in 2004.

The National Allocation Plan for the first phase of the EU ETS (to the end of 2007) provides power generation plant with carbon credits for 95% of their annual carbon emissions. The remaining credits have to be purchased from other participants in the carbon market.

The allowance levels for Phase II of the EU ETS are still in the process of being determined, and it is for this reason that we have provided sensitivities relating to a variation in the level of free allocation provided to power generation plant. The carbon credit price we have used is a market-based value. It falls within the central region of the DTI's longer term carbon credit cost estimates that range from €10/tonne to €40/tonne[26]. The sensitivity inputs are summarised in Table 3:

We recognise that any movement in free allocation levels will effect a change in the market price for carbon credits. We have not, however, studied the price-demand elasticity of the carbon market for the purposes of this report given that the global CDM Registry began its operation in February 2006[29] and the extent of Joint Implementation and Clean Development Mechanism project implementation are uncertain. For the purposes of this report, we have isolated the effect of a change in free allowance levels on the costs of generation.

Table 3 - Carbon allowance sensitivities

Carbon allowance (% annual emissions)		**Carbon price**	
		(€/T CO2)	(£/T CO2)[27]
Base Case	95%	25.80[28]	17.72
Case A	85%	,,	,,
Case B	75%	,,	,,

[26] DTi, 'UK Energy and CO_2 Emissions Projections - Updated Projections to 2020', February 2006, p59.
[27] Using GBP:EUR exchange rate of 1.456 (www.xe.com/ucc) on 15 February 2006.
[28] Calculated on the basis of €25.80/t (www.climatecorp.com/pool.htm).
[29] http://cdm.unfccc.int/CDMNews/issues/issues/I_690NV5QDGEFMK67S3UN6CPS3SWTFYN/viewnewsitem.html

System integration costs

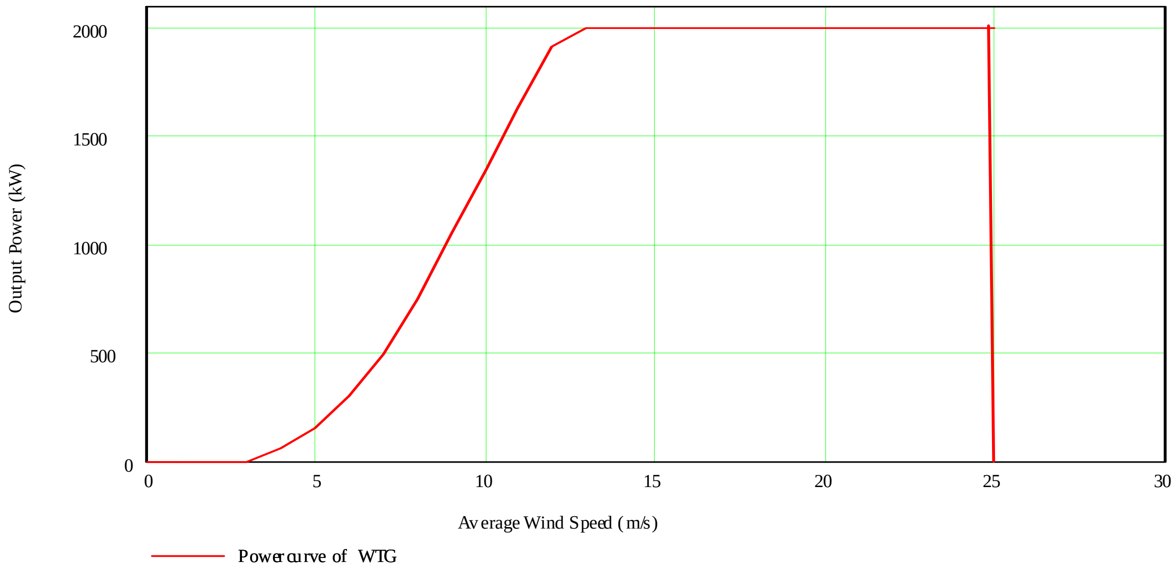
The costs of wide-scale integration of intermittent electricity generation sources, such as wind power, have been studied extensively over the previous four or so years.

It is recognised that risks remain with respect to the short-term predictability of wind farm output given the potential rate of change of turbine output with wind speed. A power curve trace for a typical turbine is illustrated in Figure 4. This shows the relatively high change in power output for relatively small changes in wind speed between 5m/s and 12m/s. The rate of change is most severe at the upper end of the output curve where the turbine maximum output would be suddenly disconnected when wind speed exceeded about 25m/s.

Whilst there are ameliorating factors from the dispersion of the individual wind turbines across the wind farm site, the turbines are still relatively closely located together in a geographic sense. The potential for 'smoothing' of output arises from a wide geographical dispersion of wind farms across the UK that gives statistical diversity of output from the whole wind turbine fleet. This has been the subject of significant study and research[30].

Findings indicate that the range of additional system costs arising from connection of significant wind generation into the GB transmission systems falls between ~0.03p/kWh[31] and ~0.3p/kWh[32] when the costs are spread across all electricity consumption in the GB market. Values of ~1.6p/kWh[32] were reported when the additional costs were recovered solely from wind generation output.

Figure 4 - Typical wind turbine generator power curve



[30] NGC (Dale et al); DTi SCAR Report (Ilex); UMIST (Professor Goran Strbac); D Milborrow (Consultant); Sustainable Development Commission: 'Wind Power in the UK', May 2005.
[31] Sustainable Development Commission: 'Wind Power in the UK', May 2005, p34; 20% wind penetration scenario for 40p/therm gas, costs spread across GB electricity demand.
[32] Power UK, Dale et al, March 2003; 20% wind penetration scenario, costs spread across GB electricity demand. (Note - this value has not been adjusted to reflect the increase in gas pricing since 2003.)

This report has used a value of 0.06p/kWh[33] as the additional cost for system integration of wind.

The GB System Operator, NGC, has a security-planning standard that allows for a maximum single event loss of demand or generation of 1,320 MW. This standard was set in the 1970s by CEGB and is based on the possible loss of two 660 MW generators (the then largest units on the system) arising from a busbar fault at the power station. Additional generation capacity will need to be held available to cover for the possibility of a trip of any plant with a single unit generation capacity in excess of 1,320 MW.

The available nuclear generation technologies have large single generation units. The largest is the EPR at 1,580 MW. This is some 260 MW in excess of the security standard maximum of 1,320 MW and would require additional generation capacity to be held available to cover for the eventuality of an EPR plant (should any be built in the UK) having an unplanned disconnection from the system. The cost of this additional capacity is that for Coal PF and CCGT plant in this report.

Assuming that the System Operator allows the connection of a single unit whose capacity exceeds the 1,320 MW security limit, the indicative costs[34] of holding 260 MW of additional generation for an EPR plant fall in the range from 0.13p/kWh for CCGT capacity to 0.21p/kWh for Coal PF capacity. If a potential owner of an EPR already operated Coal PF or CCGT plant which could operate below full capacity and be ready to accommodate the required spinning reserve, then the costs would be at the lower end of this range.

Operation and maintenance costs

Operation and maintenance costs are based on PB Power's internal database of project costs. As for the capital costs these are supplemented with independent external sources.

These include the costs of:

- Long-term service agreements;
- Routine maintenance costs;
- Costs of consumables;
- Nuclear decommissioning costs.

General and administration costs

Again these costs are based on PB Power's internal database of project costs. As for the capital costs these are supplemented with independent external sources.

These include the costs of:

- Staff;
- Administrative overhead;
- Business rates;
- Plant insurances.

Exchange rates[35]

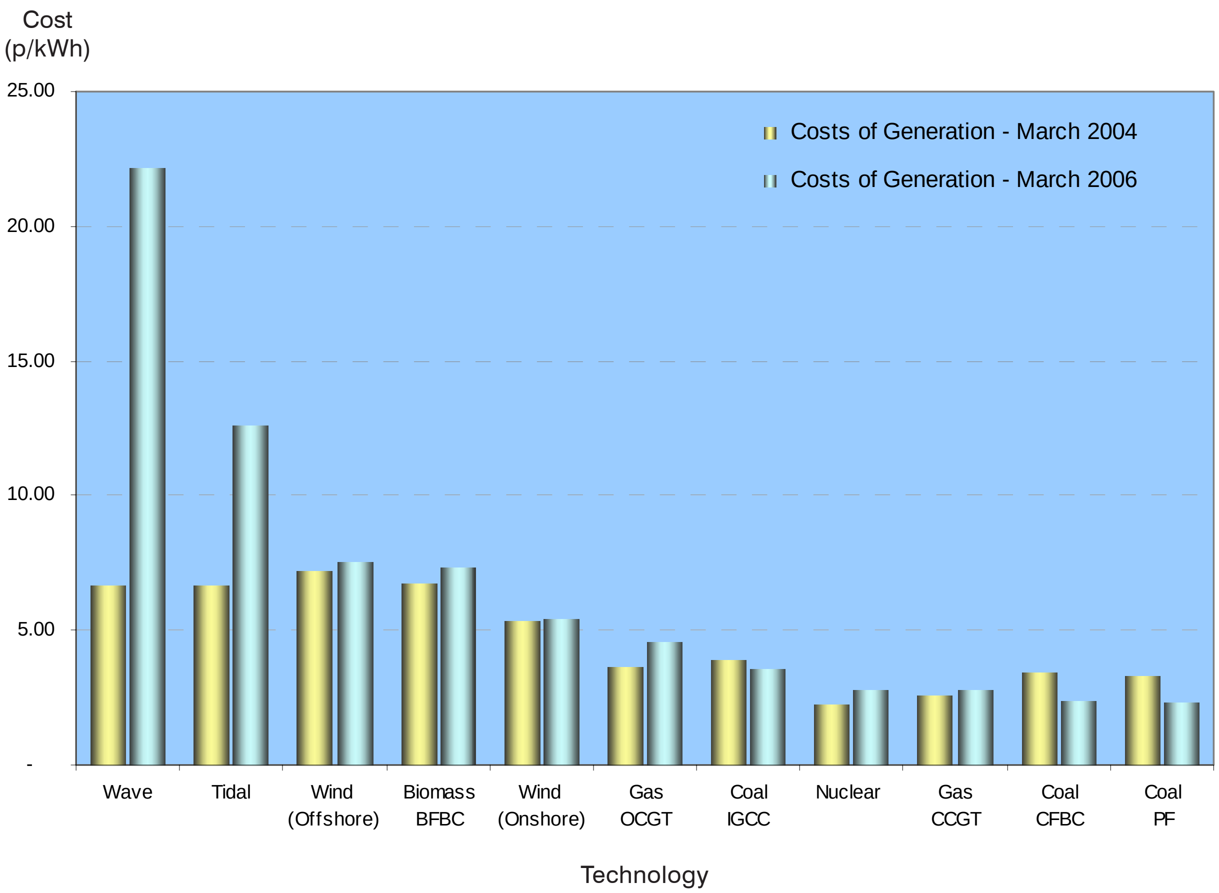
The following exchange rates have been used in deriving the capital, O&M, fuel and carbon costs in GBP:

- GBP:EUR 1:1.456
- GBP:USD 1:1.735

[33] Sustainable Development Commission, 'Wind Power in the UK', Figure 11 using a 7½ % wind penetration and 30p/therm gas price that aligns closely to the base-case long-term gas price used in this report.
[34] The costs reflect the annuitised costs for capital and operation and maintenance. No assumption has been made as to the capacity factor for such standby capacity, the potential costs of reinforcing the transmission system, nor the fuel benefits from using nuclear instead of fossil fuels.
[35] Taken from www.xe.com on 15 February 2006.

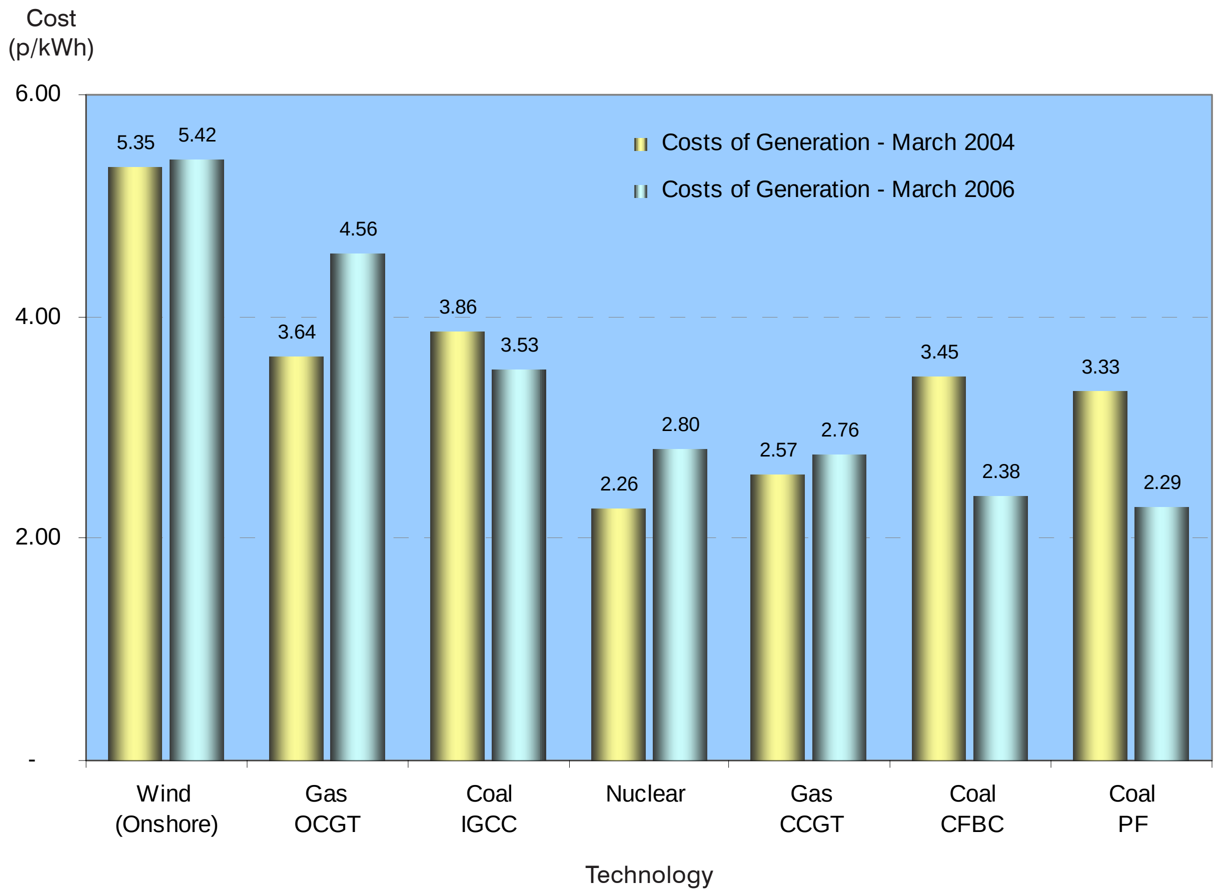
Comparison of electricity generation costs

March 2004 and March 2006
All Technologies



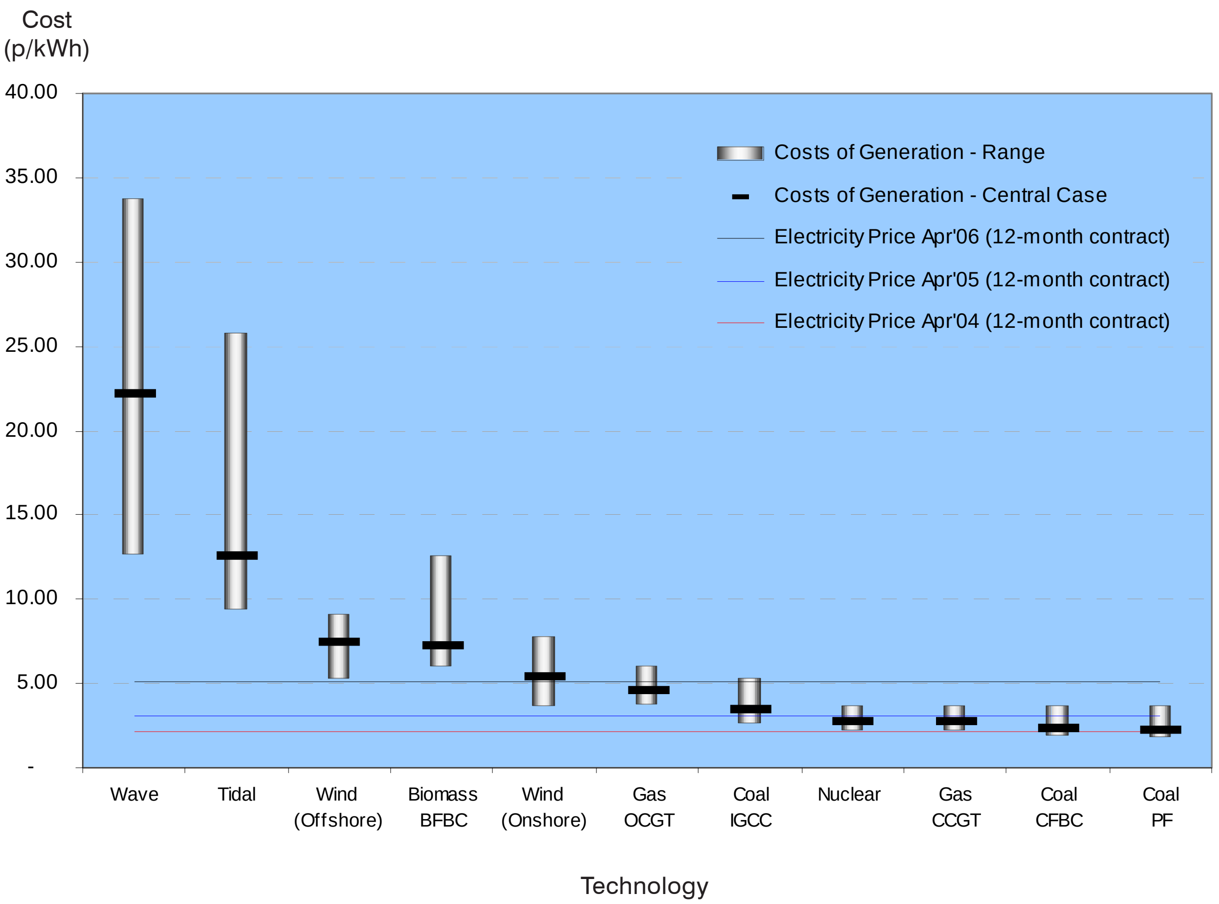
Comparison of electricity generation costs

March 2004 and March 2006
'Main' Technologies



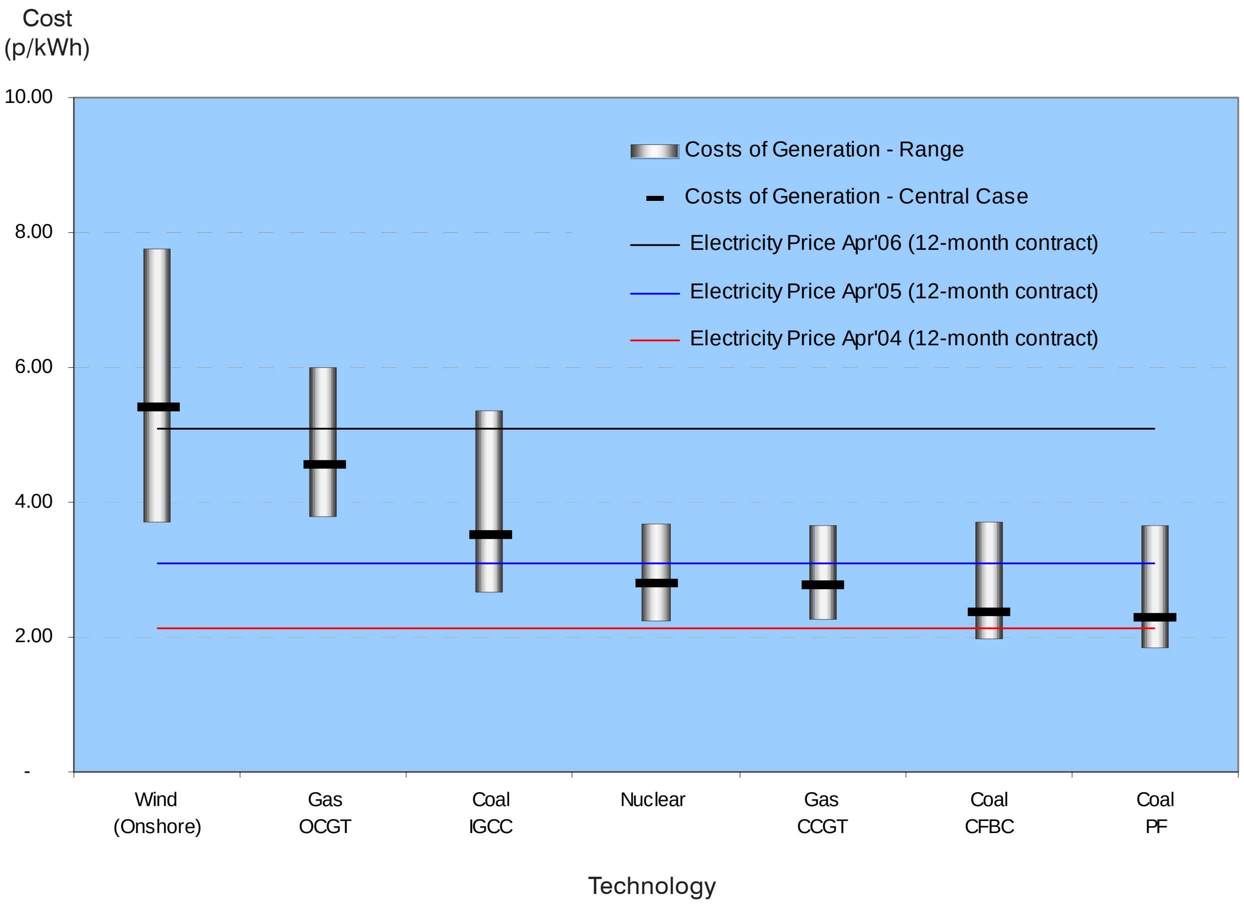
Review of the costs of electricity generation

Range of costs - All Technologies



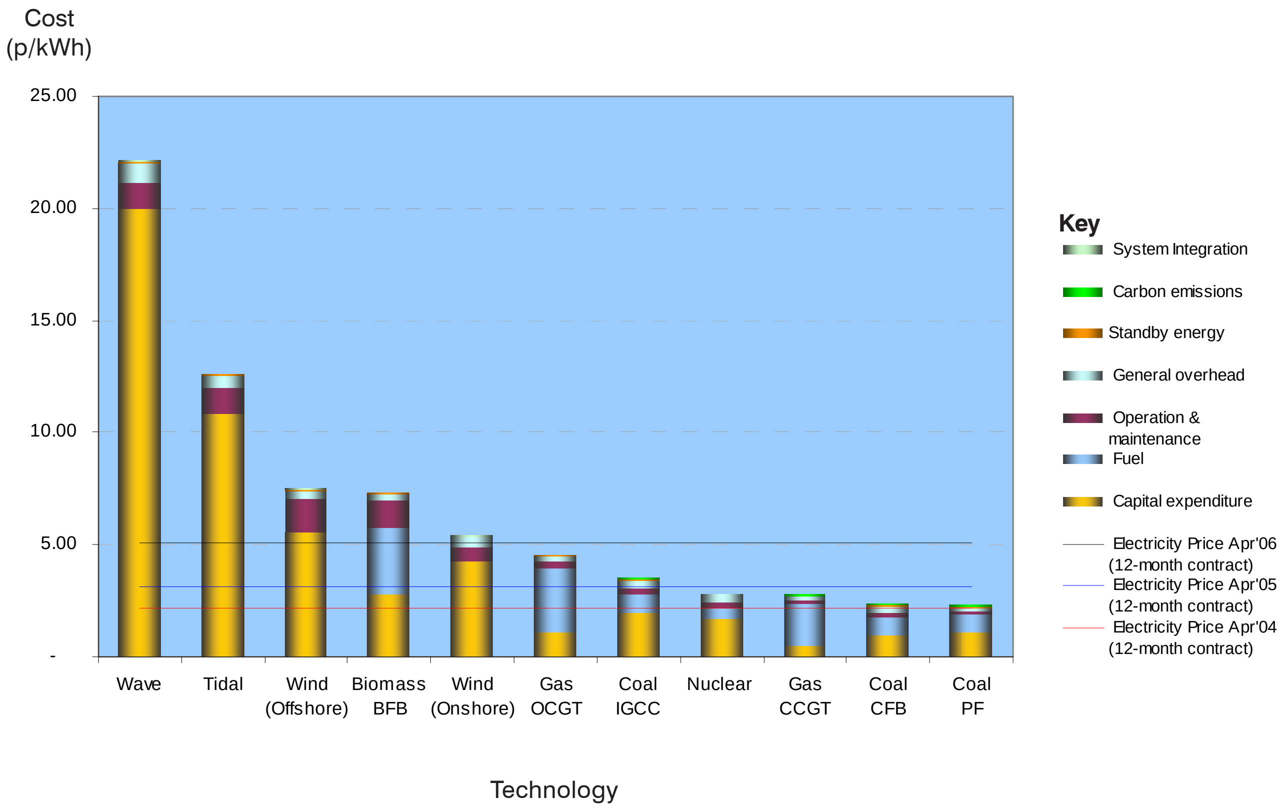
Review of the costs of electricity generation

Range of costs - 'Main' Technologies



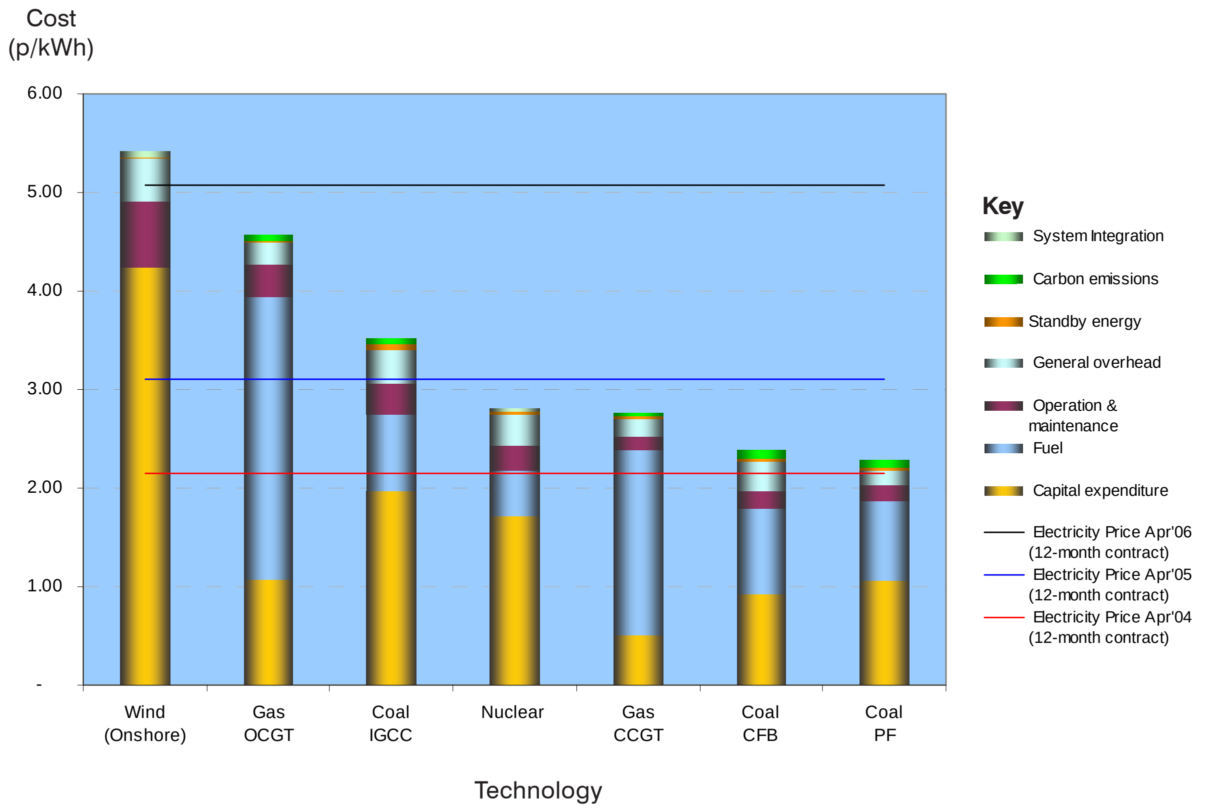
Review of the costs of electricity generation

All Technologies - Costs Breakdown



Review of the costs of electricity generation

'Main' Technologies - Costs Breakdown



Glossary

BETTA	British Electricity Trading and Transmission Arrangements
BFBC	Bubbling Fluidised Bed Combustion
CCGT	Combined Cycle Gas Turbine
CEGB	Central Electricity Generating Board
CER	Certified Emission Reduction
CFBC	Circulating Fluidised Bed Combustion
CIF	Carriage, Insurance, Freight
CO_2	Carbon Dioxide
DCF	Discount Factor
DEFRA	Department of Food and Rural Affairs
DTI	Department of Trade and Industry
EDEM	European Daily Electricity Markets
EPC	Engineer, Procure, Construct
EPR	European Pressurised Reactor
ETS	Emissions Trading Scheme
EU	European Union
EUR	Euro
GB	Great Britain
GBP	GB Pound
GJ	Giga-Joule
ICES	Industrial and Commercial Energy Snapshot
IGCC	Integrated Gasification Combined Cycle
kW	Kilo-Watt
kWh	Kilo-Watt-hour
LECs	Levy Exemption Certificates
m/s	Metres per Second
mt	Metric Tonne
MW	Mega-Watt
MWh	Mega-Watt-hour

NEI	Nuclear Energy Institute
NGC	National Grid Company
O&M	Operation and Maintenance
OCGT	Open Cycle Gas Turbine
odt	Oven Dried Tonne
PF	Pulverised Fuel
RCEP	Royal Commission on Environmental Pollution
ROCs	Renewable Obligation Certificates
SCAR	System Cost of Additional Renewables
SDC	Sustainable Development Commission
t	Tonne
UK	United Kingdom
UMIST	University of Manchester Institute of Science and Technology
USA	United States of America
USD	United States Dollar

PB POWER

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