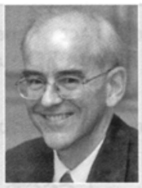
Proceedings of the Institution of Civil Engineers
Energy 161
February 2008 Issue EN1
Pages 23–30
doi: 10.1680/ener.2008.161.1.23

Paper 80006
Received 18/03/2008
Accepted 15/07/2008

Keywords:
economics & finance/nuclear power



Keith Palmer
Honorary Professor, Centre for Energy and Mining Law and Policy, University of Dundee, UK

Financing new low-carbon electricity generation in Britain

K. Palmer PhD

This paper considers the challenges involved in financing new electricity generating capacity in Great Britain in the light of government-backed carbon reduction initiatives. Impacts of carbon costs on electricity prices, the economics of various types of generation and the implications of the renewables obligations are discussed. The paper considers whether new nuclear generating capacity will be economically viable in the UK and its cost effectiveness in terms of reducing carbon emissions relative to wind power.

1. INTRODUCTION

The present paper considers the challenges involved in financing new electricity generating capacity in the electricity market in England, Wales and Scotland (Great Britain, hereafter GB) when there are strong government policy initiatives in place designed to reduce carbon emissions. It considers whether or not new nuclear generating capacity is likely to be economic and financeable in the UK and whether it is more or less cost effective than wind power in reducing carbon emissions.

The electricity market in GB is competitive. The wholesale price is determined by supply and demand. Decisions to add new generating capacity are based on two things

(*a*) the expected trajectory of the electricity price over the life of the planned investment, which is heavily influenced by the technology and carbon costs borne by the 'system marginal plant' (a term that is explained below)
(*b*) the expected costs to be incurred in developing and operating the system marginal plant over its life, including its cost of capital and any carbon costs that it expects to have to bear.

The investment decision rule is to proceed with the investment if the expected value of the output from the new plant exceeds the total costs over the plant life.

In recent years the EU and the UK government (and the devolved administrations) have developed a range of policy interventions designed to address the climate change challenge. The Kyoto international agreement provides an overarching framework within which these initiatives are developed. A full description of the UK initiatives is set out in the UK government White Paper 2007.[1] Generally these initiatives are intended to raise the costs borne by producers that emit carbon and thereby create incentives to reduce carbon emissions over time. Such interventions as the EU emissions trading scheme (ETS) raise costs incurred by all carbon-emitting electricity producers and thereby, indirectly, raise the wholesale electricity price. Certain other initiatives, such as the renewables obligation (RO) scheme, segment the market and in effect pay a premium price to a subset of producers. This scheme has different effects on the electricity price than the ETS. The main focus here is on schemes which affect directly the costs of fossil fuel producers. The implications of the RO scheme are briefly considered later.

These climate change interventions, through their impact on the costs of production of carbon-emitting producers, have an important influence on decisions about the amount, type and timing of new generating capacity added to the system. In particular, they have an important impact on the choice between high- or low-carbon-emitting technologies.

2. ELECTRICITY GENERATION INVESTMENT DECISIONS

In a market system, such as exists in GB, the wholesale electricity price will tend over time to approximate the long run marginal cost (LRMC) per unit of output of the 'system marginal plant'. The LRMC per unit of output is the average cost per unit of output incurred by new plant where costs include operating costs, capital costs including the cost of capital (the cost of capital is the return required by providers of debt and equity) and carbon costs. The 'system marginal plant' is the most expensive plant required on the system to supply incremental demand. (Note the 'system marginal plant' is not necessarily the last new plant to be added to the system. For example addition of new nuclear plant operating as baseload will not be the system marginal plant but it will make other types of (usually fossil-fuelled) plant the 'system marginal plant'.)

In the electricity market in GB, since the early 1990s, the system marginal plant has been natural gas-fired combined cycle gas turbine (CCGT) plant. A combination of high thermal efficiency, moderate gas prices and no carbon costs (until recently) has meant that new CCGT plant has been easily the cheapest incremental capacity. As a result a large amount of new CCGT plant has been built and its share of total capacity has risen at the expense of coal-fired plant. At the same time an increasing proportion of the gas supply for power generation is now

Future electricity demand	– Growth in electricity demand—assess price elasticity and impact of energy efficiency – Renewables obligation—pre-empts incremental demand for non-RO supply – Plant retirements and new inter-connectors	
Fuel cost over the long term	– Trajectory of oil and gas prices over the next 50 years, especially period 2015–2030 – Trajectory of coal prices over the same period	
Conversion costs	– Conversion costs of competing 'types' of generation (e.g. coal, CCGT) – 'Progress curves' for old and new generation technologies—reduction in unit costs over time for each type of technology	
Carbon price	– Carbon costs over the next 50 years—impact of all current and prospective schemes to reduce carbon over the next 50 years	
Cost of capital	– Required return on capital (debt and equity) for different types of generating technology – Influenced by availability of mechanisms to manage market risk	

Table 1. Electricity generation investment decisions—essential information relating to the market price of electricity

sourced from overseas, increasing the dependence of gas-fired generators on the price of internationally traded gas, which is itself closely linked to the price of oil. Consequently the level and volatility of the electricity price in GB has been heavily influenced by movements in the price of natural gas, and therefore movements in the oil price.

It has been widely assumed, until recently, that CCGT plant will remain the system marginal plant. If that proves to be correct, and if the current higher gas prices are sustained over the medium term, then both the LRMC of gas-fired CCGT and the wholesale electricity price will remain much higher than in past decades. However, as the international gas price is linked through indexation mechanisms to the price of oil, and given the extreme volatility of the oil price in recent times, the future price of natural gas, and therefore of the electricity price, is highly uncertain.

If the recent sharp increase in the price of gas were sustained over an extended period, then it is possible that CCGT plant would no longer be the system marginal plant. If coal remains much cheaper than gas (on a calorific equivalence basis) then new coal-fired plant could be cheaper than CCGT plant, despite lower thermal efficiency and higher carbon emission costs. This possibility is considered again later in the paper. For the time being the assumption is made that gas-fired CCGT plant remains the system marginal plant and therefore the LRMC of CCGT is the major influence on the electricity price.

A prospective investor in new generating capacity, whether fossil fuelled or not, must form a view about the price that will be paid for its output, and therefore about the LRMC of the system marginal plant. Table 1 summarises some of the key assumptions that must be made by a prospective investor in new nuclear plant. They include the trajectory of gas and coal prices, current and projected fuel conversion costs of gas- and coal-fired plant, the carbon emission costs of gas- and coal-fired plant and the cost of capital for each type of generating technology. Clearly there are huge uncertainties around many of these assumptions and therefore around estimates of the future electricity price.

The cost of capital is a function of the market's perception of the investment risks. This will differ depending on the type of technology and its maturity and on the magnitude and duration of the risk exposure. Generally, the greater the perceived risks, the higher the return on capital required by investors. The cost of capital is also a function of the extent to which risks can be managed, for example, by using offtake and fixed price construction contracts, or insurance. The cost of capital for new nuclear plant will be higher than for fossil fuel technologies because the technology is less mature and the payback period is much longer. Also, the proportion of total costs accounted for by the cost of capital is greater for nuclear plant because it is so capital intensive.

3. IMPACT OF CARBON COSTS ON THE ELECTRICITY PRICE

The EU ETS mechanism imposes costs on carbon-emitting electricity generators in proportion to the amount of carbon they emit per unit of energy. By raising the costs of the system marginal plant (i.e. new CCGT) the wholesale electricity price is increased. Non-carbon-emitting technologies benefit because the price they receive for their output rises but their costs do not. Conversely producers that emit more carbon per unit of energy than the marginal plant, for example coal-fired plant, incur carbon costs that are higher than the increase in the market price and therefore their profitability is reduced.

Figure 1 illustrates the point. The left-hand bar represents the costs of the system marginal plant, here assumed to be gas-fired CCGT. The height of the bar represents the LRMC of CCGT before carbon costs, expressed in £/MWh. The height of the bar will be determined by the gas price and the conversion costs over the life of the plant including the appropriate cost of capital. Since CCGT plant emits carbon, the plant will incur carbon costs per unit of energy output reflecting the amount of carbon emitted per MWh and the carbon price per tonne over the life of the plant. These carbon costs will increase the LRMC of CCGT plant, after paying carbon costs, and therefore will increase the electricity price. The amount of the increase in the electricity price resulting from carbon costs is shown in Fig. 1 as £X/MWh. The higher the carbon price, the greater will be the consequential increase in the LRMC of CCGT plant and therefore the greater the increase in the price of electricity.

The middle bar in Fig. 1 shows the situation of producers, such as nuclear and renewables, which emit no carbon. As these producers incur no carbon costs (because they emit no carbon), the fuel and conversion costs can be up to £X/MWh higher than

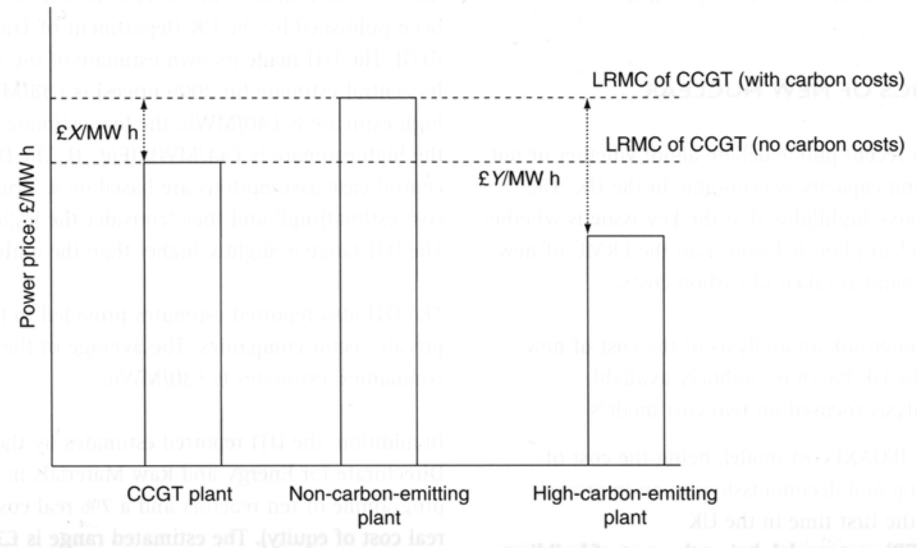


Fig. 1. Impact of carbon costs on electricity price

the cost of CCGT plant and still generate an economic return on capital employed. The higher the carbon price, the higher can be the costs of the zero carbon emitters while still generating an economic rate of return.

The right-hand bar in Fig. 1 shows the situation faced by a high-carbon emitter, such as coal-fired plant. The carbon costs per MWh are much higher than those incurred by CCGT plant, for any given carbon price, because coal-fired plant emits much more carbon per MWh than CCGT plant. (In Fig. 1 the carbon costs per MWh are shown as £*Y*/MWh). Therefore, to be economic, coal-fired plant must have production costs significantly lower than CCGT plant. The height of the right-hand bar in Fig. 1 illustrates the maximum production costs for coal-fired plant consistent with achieving an economic rate of return. The higher the carbon price, the lower the production costs of coal-fired plant must be if it is to be economic.

Figure 2 shows the estimated LRMC of new CCGT plant for a range of gas prices and carbon prices. The cost of new CCGT

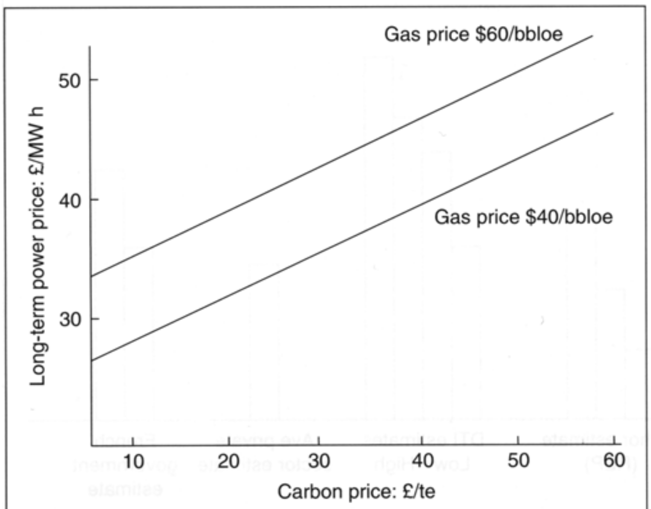


Fig. 2. Cost of CCGT at various gas and carbon prices

plant is estimated by the author using unpublished data from industry sources, but they are very similar to estimates published in 2007 by the UK government.[2]

Figure 2 shows, for example, that if the long-run gas price were equal to a price of $40/barrel oil equivalent (bbloe) and

(*a*) if the carbon price were £10/t then the LRMC of CCGT plant would be about £28/MWh

(*b*) if the carbon price were £30/t then the LRMC of CCGT plant would be about £35/MWh.

If the long-run gas price were equal to a price of $60/bbloe and

(*a*) if the carbon price were £10/t then the LRMC of CCGT plant would be about £35/MWh

(*b*) if the carbon price were £30/t then the LRMC of CCGT would be about £43/MWh.

So long as CCGT is the system marginal plant, the expected electricity price paid to all generators is very dependent on both the gas and carbon prices paid by CCGT plant over the plant life.

Several conclusions are apparent from Fig. 2.

(*a*) For any given carbon price, the higher the gas price, the greater the incentive to build alternative types of generation. If the carbon price is low then alternative generation may be high-carbon-emitting plant, for example coal (because carbon costs will be low if the carbon price is low). If the carbon price is high, then alternative generation will tend to be low-carbon-emitting.

(*b*) For any given gas price, the higher the carbon costs borne by CCGT plant, the greater will be the incentive to build low- or no-carbon-emitting generating plant.

(*c*) All investors in new plant on the system must have a view about the LRMC of CCGT, regardless of whether their investment is gas-using or carbon-emitting, because these are the major influences on the price that will be paid for their output.

(*d*) The future electricity price is highly uncertain because of the uncertainty about both the trajectory of gas prices and carbon prices over the life of the planned investment.

4. THE ECONOMICS OF NEW NUCLEAR GENERATION

There has been much recent public debate about whether or not new nuclear generating capacity is economic in the UK. The framework set out above highlights that the key issue is whether the LRMC of new nuclear plant is lower than the LRMC of new CCGT plant when account is taken of carbon costs.

In 2006 the author undertook an analysis of the cost of new nuclear capacity in the UK based on publicly available information. The analysis focused on two cost models

(*a*) a 'first of a kind' (FOAK) cost model, being the cost of building, operating and decommissioning an improved plant design for the first time in the UK
(*b*) a 'replication' (REP) cost model, being the cost of building, operating and decommissioning sequentially a series of at least four new plants.

This approach was adopted because it is well known that unit costs fall over time for various reasons, including maturing of the regulatory environment, economies in procurement and benefits of learning-by-doing, when a number of plants are constructed sequentially.

The assumptions used in the analysis and the sources for the assumptions are summarised in the Appendix. They are drawn from a wide range of published sources in the UK and internationally. Central assumptions erred deliberately on the side of prudence and the ranges around the central values for each input parameter were set to reflect the extent of the acknowledged uncertainty (hence the ranges for waste disposal and decommissioning costs are particularly wide). Because new nuclear plant is so capital intensive a key assumption was the cost of capital. The analysis used an estimated ex ante gross return on debt of 4% real (i.e. excluding inflation effects) and a required post-tax geared return on equity in the range 9–13% real. Any estimate of new nuclear costs is founded on many assumptions about input parameters, many of which are highly uncertain. Therefore the results are presented as a range of values, rather than as point estimates.

The left side of Fig. 3 sets out the results of the author's analysis in 2006 prices. In the FOAK model, the central estimate of the unit cost is £33/MWh and the range is £27–39/MWh. In the REP model, the central estimate is £28/MWh and the range is £24–33/MWh. As expected the REP model unit cost range is significantly lower than the FOAK model range.

More recent estimates of the cost of new nuclear plant have been published by the UK Department of Trade and Industry (DTI). The DTI made its own estimate of the cost of new nuclear. Its central estimate (in 2006 prices) is £38/MWh, the central–high estimate is £40/MWh, the low estimate is £31/MWh and the high estimate is £44/MWh (Fig. 3). The DTI note that their central case assumptions are based on a 'prudent approach in cost estimat[ing]' and they 'consider the high cost case unlikely'. The DTI range is slightly higher than the author's FOAK estimate.

The DTI also reported estimates provided to them by various private sector companies. The average of the private sector companies' estimates is £30/MWh.

In addition, the DTI reported estimates by the General Directorate for Energy and Raw Materials in France, based on a programme of ten reactors and a 7% real cost of capital (10% real cost of equity). The estimated range is £31–37/MWh (Fig. 3). This estimate can be regarded as well informed because of the extensive French experience in building new nuclear plant. This range is slightly higher than the author's REP estimates.

The evidence from all of these sources suggests a range for the unit cost of nuclear energy from new plants of £30–40/MWh. A FOAK plant is likely to have costs towards the high end of this range. A programme of, say, four or more reactors of the same design is likely to have costs towards the low end of the range.

Figure 4 shows the top and bottom end of this range mapped as parallel horizontal dotted lines on to Fig. 3. The lines are horizontal because the cost of nuclear energy does not change as the carbon price changes. It shows that if the cost of nuclear energy is at the top end of the range (£40/MWh) and

(*a*) if the cost of gas equals \$40/bbloe then nuclear energy is economic if the carbon price is about £39/t or higher on average over the life of the investment
(*b*) if the gas price equals \$60/bbloe then nuclear energy is economic if the carbon price is much lower, about £23/t.

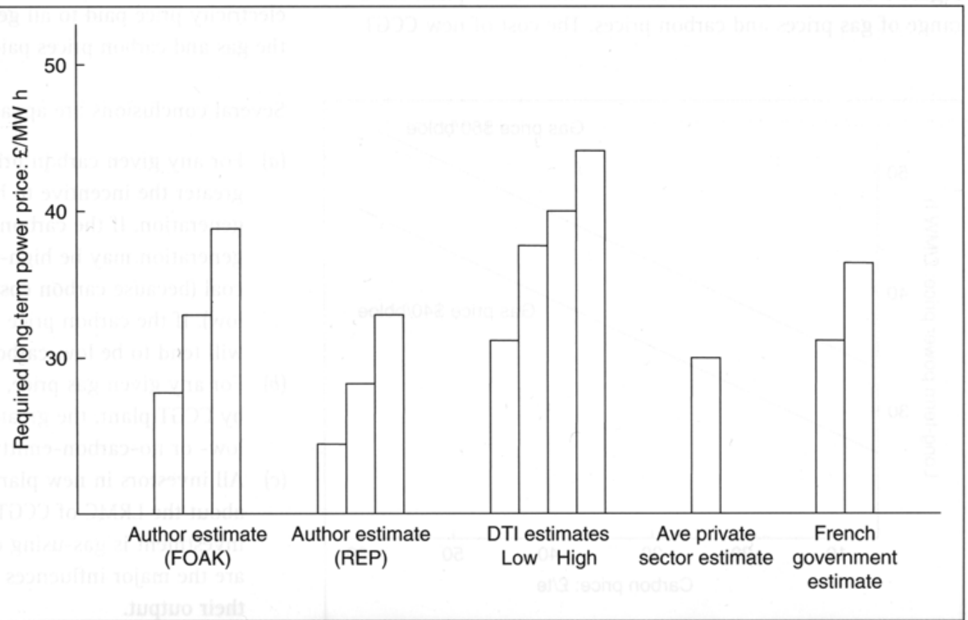


Fig. 3. Estimated unit cost of nuclear power

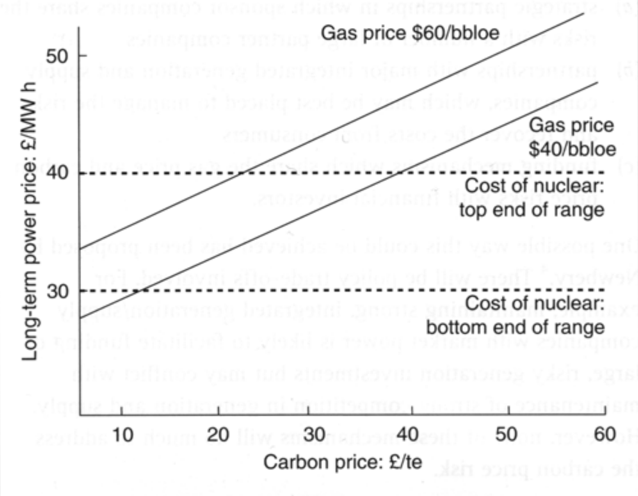


Fig. 4. Carbon price at which nuclear power is economic

If the cost of nuclear energy is at the bottom end of the range (£30/MWh) and

(*a*) if the cost of gas equals $40/bbloe then nuclear energy is economic if the carbon price is as little as £12/t

(*b*) if the cost of gas equals $60/bbloe then nuclear energy is economic even if the carbon price is zero.

At the time of writing the oil price was much higher than this range (above $100/barrel). If current gas prices were confidently to be sustained at these levels over the life of the investment, then nuclear energy would be economic at a zero carbon price, even if costs were at the top end of the range of estimated unit costs. However, there is great uncertainty about what the trajectory of oil and gas prices will be over the 40 year life of new nuclear plant.

The conclusion of this analysis is that if (*a*) long run gas prices were confidently expected to remain in the range $40–60/bbloe and (*b*) investors were confident that the costs of a programme of new nuclear build would be towards the lower end of the estimated range (£30–35/MWh), then nuclear would be economic if the carbon price over the life of the plant were expected to be in the range £10–25/t or higher. If investors felt that the costs of a programme of new nuclear build would more likely be at the high end of the range (£35–40/MWh), for the same gas price assumptions, the 'required' average carbon price over the plant life would increase to £25–40/t.

5. ECONOMICS OF RENEWABLE GENERATION

The DTI report also sets out estimates of the cost of onshore and offshore wind power (Fig. 5). The cost of onshore wind is estimated at £50–65/MWh and offshore wind at £58–90/MWh. The cost of wind power is very location specific and some schemes will have costs that are significantly higher or lower than these averages. An unpublished study undertaken by the Cambridge Economic Policy Associates (CEPA) and Climate Change Capital has estimated the cost of onshore and offshore wind and marine technologies taking explicit account of the cost reductions expected over time as a result of economies of scale and scope and learning by doing.[3] The study estimated a current cost of offshore wind of £62/MWh (towards the lower end of the DTI range) and estimated that costs would reduce, if there is a large-scale roll-out of well-positioned offshore schemes, to about £40–45/MWh by 2020. This is somewhat higher than the top end of the range of the cost of new nuclear.

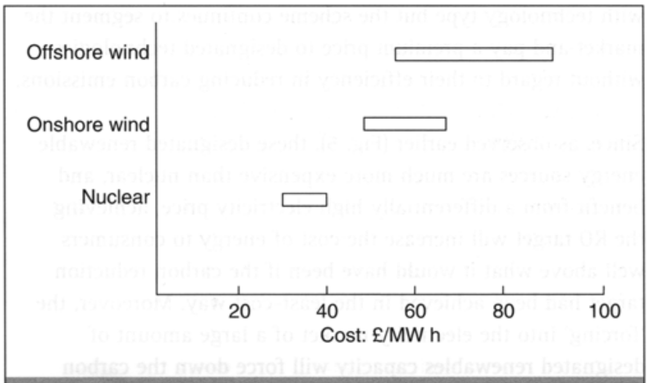


Fig. 5. Cost of renewable generation and coal-fired plant[2]

Throughout the period to 2020 the cost of offshore wind is considerably higher than the cost of CCGT even if gas prices remain above $60/bbloe unless the carbon price exceeds £60/t. Therefore, for all plausible combinations of gas and carbon prices, even after further cost reductions are anticipated, offshore wind will require continuing large subsidies, over and above the benefit arising from the carbon price, if investments are to generate an economic rate of return.

6. ECONOMICS OF NEW COAL-FIRED GENERATION

The DTI estimates the technical and fuel costs of coal-fired generation (before carbon costs) using different technologies in the range £25–28/MWh. If the carbon price were very low and gas prices remained high relative to coal prices then new coal-fired generation would be cheaper than new CCGT. As a result, a new generation of coal-fired power stations might be built instead of new gas-fired plant. If this did happen, then once the front-end capital costs are sunk, high carbon emissions would be locked-in for the life of the plant. Given that coal-fired plant generates approximately 2·3 times more carbon per unit of energy than CCGT, there would be no way that the government's ambitious carbon reduction targets could then be met. This highlights the central importance of government policies underpinning a firm expectation of a sustained high carbon price if the climate change targets are to be met. A firm expectation of an average carbon price in the range £20–25/t is needed if there is not to be further new build of 'dirty' coal-fired plant at the expense of 'cleaner' CCGT. This risk is particularly great at the present time when gas prices are very high and there is no transparent carbon price beyond a few years, making the economics of new coal-fired build attractive.

7. IMPLICATIONS OF THE RENEWABLES OBLIGATION

The RO mandates that 20% of energy must be from designated renewable energy sources. This implies that a much higher share (30–40%) of electricity must be sourced from designated renewable energy (mostly wind and marine energy). The original RO scheme worked in a way that raised the price paid to all designated renewables to whatever level was required to deliver the target. Therefore all designated renewable energy received the price set by the highest cost designated supplier. Recent amendments to the scheme introduce some price differentiation with technology type but the scheme continues to segment the market and pay a premium price to designated technologies without regard to their efficiency in reducing carbon emissions.

Since, as observed earlier (Fig. 5), these designated renewable energy sources are much more expensive than nuclear, and benefit from a differentially high electricity price, achieving the RO target will increase the cost of energy to consumers well above what it would have been if the carbon reduction target had been achieved in the least-cost way. Moreover, the 'forcing' into the electricity market of a large amount of designated renewables capacity will force down the carbon price and sharply undermine the economics of cheaper low-carbon-emitting alternatives, including nuclear power. It also risks bringing into the system new coal-fired generation, which would be the least-cost new-build at low carbon prices, thereby increasing the carbon intensity of electricity generation. High-cost renewables would end up inducing a new generation of high-carbon-emitting coal-fired power stations.

8. CAN NUCLEAR ENERGY BE FINANCED?

The analysis above shows that nuclear energy is economic at quite modest carbon prices if gas prices are confidently expected to remain high over the long term. However, it does not follow that companies seeking to build new nuclear plant will necessarily be able to finance their planned investments. There are obvious major challenges to be overcome.

(*a*) The great uncertainty about the future gas price, especially in the period 2015–2030, which is the period when early production from new nuclear plant would be sold into the electricity market. It is not easy or cheap to hedge this price risk that far into the future. The response of investors will be to require an additional risk premium in the cost of capital, raising the required cost of capital towards the high end of the range of estimates set out above.

(*b*) The great uncertainty about the future carbon price, especially in the period 2015–2030. This is a greater risk than the gas price risk because the carbon price is a 'policy' price and subject to the unpredictable outcome of political bargaining in the UK and internationally over an extended period of time. Whereas the future gas price can be projected against the background of reasonably well understood market factors, the carbon price is little more than a guess unless effective policies can be devised which reduce the uncertainty perceived by investors about its value over the long term.

(*c*) The interaction between the electricity and carbon markets and the RO scheme in the UK is such that the carbon price becomes even more uncertain. Success in delivering the RO target is likely, as things stand, to depress the carbon price, deter investment in non-carbon-emitting nuclear plant and, paradoxically, induce new investment in coal-fired plant which emits large amounts of carbon.

These challenges exist for all new electricity generation investments. However, they are particularly great for new nuclear capacity because nuclear plant is particularly capital intensive, the investment is 'sunk' up-front and the life of the plant is very long (around 40 years). There are ways in which generation companies can act to manage the market risks to some extent. They include

(*a*) strategic partnerships in which sponsor companies share the risks with a number of large partner companies

(*b*) partnerships with major integrated generation and supply companies, which may be best placed to manage the risks and recover the costs from consumers

(*c*) funding mechanisms which share the gas price and carbon price risks with financial investors.

One possible way this could be achieved has been proposed by Newbery.[4] There will be policy trade-offs involved. For example, maintaining strong, integrated generation/supply companies with market power is likely to facilitate funding of large, risky generation investments but may conflict with maintenance of strong competition in generation and supply. However, none of these mechanisms will do much to address the carbon price risk.

The Climate Change Bill (currently going through Parliament) is an attempt to provide clearer long-term signals about the government's intentions to reduce carbon emissions and indirectly to signal its expectations about the future carbon price. The government has also signalled that it is willing, if necessary, to take further steps to increase certainty about the future carbon market. It seems likely to the present author that some form of enhanced mechanism will be needed to reduce uncertainty about the forward price for carbon over the next 25 years. Such a mechanism, if adopted, should be technology neutral, that is it should not benefit one type of climate change technology over another. This will ensure that the lowest cost response to reducing carbon is adopted and that the increase in customer bills arising from carbon emission reduction is minimised. Meanwhile the government should review the RO scheme to reduce its perverse consequences for the carbon markets and for achievement of its own carbon reduction target.

9. CONCLUSIONS

The conclusions of the paper are as follows.

(*a*) The major influence on the wholesale price of electricity in the GB market is the long-run marginal cost of new CCGT plant. The LRMC of CCGT plant will be heavily dependent on the long-run price of gas and carbon, both of which are highly uncertain.

(*b*) If long-run gas prices were confidently expected to remain in the range \$40–60/bbloe, and investors were confident that the costs of a programme of new nuclear build would be towards the lower end of the estimated range (£30–35/MWh), then nuclear would be economic if the carbon price over the life of the plant was expected to be in the range £10–25/t. If investors felt that the costs of a programme of new nuclear build would more likely be at the high end of the range (£35–40/MWh), for the same gas price assumptions, the 'required' average carbon price over the plant life would increase to £25–40/t. If the gas price were to remain above \$80/bbloe then nuclear would be economic at carbon prices of less than £10/t even if costs were at the high end of the range.

(*c*) Coal-fired generation would be cheaper than CCGT new build, if gas prices remained within the \$40–60/bbloe range, if expected carbon prices were lower than £20–25/t. If a new generation of coal-fired plant were built then the carbon reduction targets set by the government could not be met. This highlights the importance of reducing uncertainty about the future carbon price and ensuring that the average price is high enough to drive development of a new generation of efficient low-carbon-emitting technologies, including nuclear.

(*d*) New nuclear generation is a much cheaper way of reducing carbon emissions than expansion of offshore wind or marine technologies over the period to 2020 and remains cheaper in the long term even after accounting for anticipated reductions in unit costs over time.

(*e*) Delivery of the renewables energy target with the current RO mechanism will increase electricity costs to consumers well above what they would have been, had the least-cost low-carbon-emitting generation mix, consistent with achieving the carbon target, been used. Moreover the RO mechanism seriously risks depressing the carbon price to such a low level that relatively efficient low-carbon-emitting technologies become uneconomic. Paradoxically, high-cost renewables could end up inducing a new generation of high-carbon-emitting coal-fired power stations, making achievement of the carbon reduction target impossible.

(*f*) Even though the analysis shows that new nuclear plant is economic at quite modest carbon prices, if gas prices remain high over the long term, it does not necessarily follow that the investments will be financed. The considerable uncertainty about future gas and carbon prices makes investment in new nuclear plant particularly risky. New mechanisms supported by government may be needed to ensure that the future price of carbon is less uncertain and set at an average level consistent with achieving the climate change goals. New mechanisms, if adopted, should be technology-neutral and should not favour one type of low-carbon-generating technology over others. In addition the government should revisit the mechanism for inducing renewable energy technologies to avoid a situation where the perverse unintended consequence is to induce new build of a generation of 'dirty' coal-fired power stations.

APPENDIX

Assumptions used to estimate cost of new nuclear plant

The analysis focuses on two cost models

(*a*) FOAK engineering, being the expected costs of building, operating and decommissioning an improved design for the first time in the UK

(*b*) REP engineering, being the expected costs of building, operating and decommissioning the same design several more times serially.

Table 2 summarises the key assumptions used in the analysis for the FOAK and REP cost models. The technical assumptions are based on a detailed review of literature, industry and government publications as current in 2005. Sources are listed in the references.[5–13]

The following points should be noted about the technical assumptions.

(*a*) Pre-development costs are those technical and regulatory costs that must be borne by sponsors before they know whether or not the plant will obtain approval and be built. In absolute amount they are not very large but the risks associated with them are very great (because if the plant is not approved they have to be written off). In the analysis the range for this estimate is very wide. In the evaluation they are accumulated with 10% per annum real cost of capital and charged to the project as a development fee at financial close.

(*b*) Waste disposal costs are clearly highly uncertain. They include the management of spent nuclear fuel and the disposal of intermediate and high-level nuclear waste. The

Assumptions	FOAK (Central)	FOAK (Ranges)	REP (Central)
Technical assumptions			
PWR Gen III + technology	1200	1200	1200
Plant capacity (MW)	250	50%	110
Pre-development costs (£ million)	1000	750–1250	900
Construction cost (£/KW)	6	5–7	5
Build period (years)	60	45–90	60
Non-fuel operating costs (£/KW/Year)	3	2·7–3·3	3
Front-end fuel costs (£/MWh/year)	85	75–90	85
Plant availability (average) %	80	75·85	80
Plant availability (first 2 years) %	40	30–60	40
Plant life (years)	1·3	0·4–2·2	1·3
Waste disposal (including spent fuel management) (£/MWL)	250	150–350	250
Decommissioning (£/KW)			
Financial assumptions			
Constant 2006 prices			
Return on liability fund	2·5% real		
Corporate tax	Regime applicable in 2006		
Financial structure	50% gearing 20 year average debt term 6·5% nominal cost of debt		
Inflation	2·5% per annum		
Cost of equity	9–13% real		

Table 2. New nuclear generation—key technical and financial assumptions

solutions for nuclear waste disposal are not yet clear and therefore neither is the cost of disposal. Here, a wide range of possible costs of waste disposal have been estimated based on experience internationally and estimates in published UK studies. The estimates used here are deliberately conservative, given the extent of the uncertainty. It is assumed that the costs of waste disposal will be borne by the private sector. The government is assumed to set a waste disposal levy on the basis of nuclear power generated (MWh) and the £/MWh levy is calculated. This levy is assumed to be paid as the output is generated and the proceeds placed in a fund which earns a real return of 2·5%. The levy proceeds and accrued interest are used to fund waste disposal costs when they occur.

The table also sets out key financial assumptions. Given the capital-intensive nature of new nuclear generation, a key assumption is the cost of capital, that is the return on capital that investors (debt and equity providers) expect to earn on an investment with this amount of risk. The assumed financial structure is stylised. Gearing is 50% and the real cost of debt is 4%. The 'right' cost of equity, that is the return on equity required by equity investors for this degree of risk, depends on whether the market risk can be hedged. The low end of the range for the cost of equity (9% real) would be appropriate if the market risk had been hedged through forward sales contracts. The high end of the range (13% real) would be appropriate if the market risk remained entirely with the investors in the plant.

REFERENCES

1. Department for Trade and Industry. *Meeting the Energy Challenge. A White Paper on Energy.* DTI, UK, 2007.
2. Department for Trade and Industry. *The Role of Nuclear Power in a Low Carbon UK Economy: A Consultation Document.* DTI, UK, 2007.
3. Cambridge Economic Policy Associates and Climate Change Capital. *Assessment of the Benefits from Large Scale Deployment of Certain Renewable Technologies.* CEPA/Climate Change Capital, 2005, Report for the Office of Gas and Electricity Markets.
4. Newbery D. Be creative and reduce the risk of nuclear investment. *Financial Times*, 2008, 9 January.
5. Royal Academy of Engineering. *The Cost of Generating Electricity.* Royal Academy of Engineering, London, 2004.
6. University of Chicago. *The Economic Future of Nuclear Power.* University of Chicago, Illinois, 2004.
7. Uranium Institute. *Nuclear Power: Least Cost Option for Baseload Electricity in Finland.* Uranium Institute, London, 2000.
8. General Directorate for Energy and Raw Materials. France.
9. Canadian Energy Research Institute. *Levelised Unit Electricity Cost Comparison of Alternative Technologies for Baseload Generation in Ontario.* CERI, Calgary, Canada, 2004.
10. US Department of Energy. *Study of Construction Technologies and Schedules, O&M Staffing Costs, Decommissioning Costs and Funding Requirements for Advanced Reactor Designs.* US DOE, Washington, 2004.
11. Energy Information Administration. *An Analysis of Nuclear Power Plant Operating Costs: a 1995 Update.* EIA, Office of Integrated Analysis and Forecasting, US Department of Energy, Washington, 1995.
12. Organisation for Economic Co-operation and Development. *Projected Costs of Generating Electricity.* OECD, Paris, France, 1998.
13. EDF. *EPR Costs according to French Industry Ministry.* EDF, France, 2005.