sustainable development commission

The role of nuclear power in a low carbon economy

Paper 4: The economics of nuclear power

An evidence-based report for the Sustainable Development Commission by Science & Technology Policy Research (SPRU, University of Sussex) and NERA Economic Consulting

March 2006

22 November 2005

Economics of Nuclear Power

A Report to the Sustainable Development Commission

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Executive Summary

When the UK Government published its energy White Paper in February 2003 there was no imminent prospect of a decision on building new nuclear power stations. Since that time, a range of factors has led to an intensification of the debate about nuclear power. Government has now announced a major new energy review in 2006 in which nuclear power will be a significant subject.

However, uncertainties about the costs of future nuclear generation have not materially reduced. Important examples are:

- neither of the two main potentially competing designs of reactor have yet been built anywhere in the world and recent international experience of nuclear ordering offers few direct lessons for the UK;
- the UK safety licensing system has yet to give serious consideration to either design;
- the UK's history in building nuclear projects and some other large infrastructure has been poor. While there are solid grounds for expecting that future construction would be less costly, 'appraisal optimism' remains a real risk.

Nuclear power gives rise to major externalities (impacts not captured, or borne, by producers or consumers). Positively, greenhouse gas emissions are reduced and security of supply may be enhanced. Negatively, there are short and long-term risks of radiation release and also proliferation issues. Valuation of these effects is problematic and only in the case of greenhouse gas emissions saved is useful valuation even likely. However, we do not draw on any such estimates in this paper, concentrating instead on the direct costs of nuclear power.

The overwhelmingly important element in the total costs of nuclear power is the cost of construction (capital cost), the temporal component of which is a significant determining factor. This typically accounts for some 60% to 75% of the generating cost of nuclear power. Other elements of nuclear cost are either subject to limited uncertainty - operating performance, the cost of fuel and operations and maintenance (O&M) - or are potentially manageable even at low rates of discounting the future - waste and decommissioning.

Only two reactor types, the BNFL/Westinghouse AP1000 and the Areva/Framatome/ Siemens EPR, seem likely to compete in any future UK market. Finland started building the world's first EPR in late summer 2005, and no AP construction has yet started.

There are few sources of data on the costs of future nuclear power that relate directly to UK circumstances. The more minor components of cost, especially fuel, O&M and operating performance, can be forecast with a relatively narrow margin of uncertainty. This is either because of recent real-world concrete experience in the UK and elsewhere or because market structures and resource availability are well-established and stable. The various studies consulted would suggest aggregate figures for fuel and O&M costs for future UK reactors would probably be in a range of 0.65p/kWh to 0.85p/kWh. Operating availability of 85% would also seem reasonably probable.

The problematic category is capital costs, where there is no recent European or North American experience. Examination of the limited number of published capital cost estimates that apply directly to the UK shows that all appear to derive from studies originally designed to apply to other countries and from vendors of reactor systems. This limits the confidence that can be placed in such figures for the following principal reasons:

- overseas-based cost numbers do not easily translate into reliable UK cost number due to a range of factors, including exchange rate problems, the existence across countries of different regulatory systems, and differences in industrial and labour market structures;
- the expected cost of reactors depends very much on whether a single reactor is being considered or a programme of essentially identical reactors. Programmes, typically of eight or ten reactors, should offer significantly lower unit cost, but for such savings to be realised, an up-front commitment to the programme would be needed; and
- vendors of reactor systems have a clear market incentive, especially ahead of contractual commitments, towards 'appraisal optimism' - in other words to under-estimate costs. This means that the risks attached to cost estimates are 'asymmetrical' - the chances of actual costs turning out to be higher than forecast costs are much higher than actual costs turning out to be lower.

The consortium building the Finnish reactor contract has offered a turnkey (fixed price) contract. If such a contractual structure were used in the UK, it might seem to offer reduced cost uncertainty. However it is not clear that vendors would offer to fix all costs, and while they would be absorbing most of the risks, they would not necessarily reduce them. There is not yet any way of pinning down a realistic capital cost estimate for new reactors in the UK: we can get some idea of the minimum cost, but significantly higher costs are possible, and costs remain subject to major uncertainty.

Internationally, 24 reactors are under construction. Of these, 13 use designs that would be unambiguously out of contention for future UK use (mainly Russian designs and Indian adaptations of foreign designs) and a further ten use designs that will have real difficulty in competing in the UK (boiling water reactors and heavy water reactors). This makes the relevance of overseas experience limited. Some data are available in relation to the recent decision in Finland to build an EPR, but this is at an aggregative level, and the nature of the apparently fixed price contract is not public. China has built recent nuclear plants and has two currently on order, and the Chinese Government has announced an intention to build up to 30 more in the relatively near future. The cost data relating to the Chinese reactors are of very limited relevance to the UK.

It seems improbable that a UK Government would directly finance all or a large part of a nuclear reactor project or programme. The private sector would need to take the lead and either corporate finance or project finance would be possibilities: the latter is complex but perhaps the more probable. Government assistance in some form would, however, almost certainly be needed, and could take several forms, for example government guarantees of bank or bond financing, tax allowances, and grants (probably financed by consumers) for a range of costs. A low carbon obligation could be imposed on electricity suppliers, requiring them to source a specified proportion of their sales on renewables and nuclear power. Such a scheme could benefit from the experience of the former 'Non-fossil fuel obligation' which ran from 1990 to 1998 and could be seen as a major extension to the current Renewables Obligation on suppliers. This might involve a fixed or minimum sale price for nuclear output over many years. While back end costs (waste and decommissioning) are highly uncertain and could be substantial, financing these over the lifetime of a new plant at even a low rate of assumed fund accumulation would make such costs potentially quite small.

Given the importance of capital costs, and the extent of uncertainties in such costs for nuclear power, one of the most important factors determining the generating cost of nuclear electricity is the cost of capital. A good starting point for the cost of capital is the rate of return that the economic regulator Ofgem allows utilities to earn on regulated (low risk) assets. This is currently 6.5% and it seems probable that a first-of-a-kind nuclear project would require a premium of 2 to 3 percentage points above this. This would imply a discount rate of around 9%, assuming that all other uncertainties (especially cost or time overruns) have already been allowed for elsewhere in the analysis.

The combination of any new UK nuclear investment over the next few years and the retirement of old nuclear plant will mean that nuclear capacity would continue to be a baseload generator (running round the clock, all year). This means that nuclear output will continue to attract relatively lower prices for its output than plants with more flexible operational characteristics. In relation to current market rules, some of the public policy mechanisms already mentioned - for example, imposing obligations to buy nuclear output - would reduce market efficiency by creating distortions and would also risk breaching European Commission rules on state aids, by placing nuclear plant in an unduly favourable commercial position.

The 'knock-on' effects of a large (say ten unit) nuclear programme are difficult to gauge. The appetite of the market for new gas-fired generation would probably reduce, as nuclear and gas-firing would be competing technologies for baseload power. The impact on renewables investment is more difficult to determine in advance: much would depend on whether or not Government's willingness to finance renewables was diminished by commitment to a nuclear programme and this is a political judgment. It is also difficult to predict whether the private market's appetite to invest in renewables would be affected. Overall there is no basis for predicting the degree to which a nuclear programme would lead to 'crowding out' of investment in renewable energy.

1. Introduction

This Report is submitted to the Sustainable Development Commission (SDC), jointly by NERA Economic Consulting (NERA) and SPRU – Science and Technology Policy Research - of the University of Sussex. It is the final deliverable under a research project commissioned by the SDC to investigate the evidence on the costs of nuclear power generation.

The contents of this report are as follows:

- Section 2 sets out the policy and market contexts in which the issue of nuclear power generation costs arises, and raises the issue of externalities;
- Section 3 provides a breakdown of the main components of electricity generation costs, and how, historically, these components differ in the case of nuclear compared to the other main forms of generation;
- Section 4 provides important background to the available sources of data, first by outlining the main reactor types, and then by summarising the main sources;
- Section 5 then sets out an analysis of the main sources of data on nuclear generation costs;
- Section 6 presents a review of the international evidence on recent experience with nuclear generation, first reviewing the current developments on a world-wide basis, and then focussing in more detail on the specific cases of Finland and China; and
- Section 7 then discusses potential financing mechanisms for new nuclear investment in the UK, and the electricity market issues that potentially arise.
- Section 8 includes a bibliography.

In Appendix A we provide further detail on discounting and the costs of capital issue, and in Appendix B we provide a glossary of terms.

2. The Policy and Market Context

As recently as February 2003, the Government's White Paper on energy argued that nuclear power was an uneconomic option in then-current UK conditions[1] and that this meant that no active consideration of new nuclear investment was needed. There was no serious disagreement on this point in public debate at that time. In the course of the last year or so, however, there has been major renewed interest in the prospects for new nuclear build in the UK. This interest has been accompanied by a number of reports which appear to show that the economic status of nuclear power has improved. The detail of recent reports on the economics of nuclear power is a main subject of this report. But more broadly, there is the question of what it is that appears to account for the improved prospects of nuclear power. A number of factors can be identified:

- Fossil fuel prices, especially for oil and natural gas, have continued to rise and are currently at high levels. Given that nuclear power would compete largely with gas-fired power, these price increases – if sustained over the next decade and more – would improve the relative position of nuclear power.
- Climate change mitigation remains an important political priority and there are increasing doubts that renewable energy and energy efficiency will have as much potential for reducing carbon emissions as the 2003 White Paper anticipated. Two issues stand out: the recent rise, not fall, in annual carbon emissions; and the much-publicised concerns about local impacts, and hence problems in gaining planning approval for wind projects.
- For a variety of reasons, security of energy supply has become more prominent in the political debate on energy policy. Contributory causes appear to be: concerns about the ability of both gas and electricity systems to meet winter peak demands; the increases in oil and gas prices already mentioned; and the realisation that gas and oil self-sufficiency are coming to an end, combined with concerns about the long-term reliability of major overseas sources of supply. Security of supply is a complex and under-analysed subject, but to the extent that greater domestic self-sufficiency in energy is perceived as adding to security, nuclear power is potentially attractive.
- While as at 2003 no OECD Europe/North American country had ordered a new nuclear power plant for ten years, Finland committed to a new nuclear plant in 2004 and started construction in summer 2005. France also made a decision in principle to order a new nuclear plant in 2005 and seems likely to go ahead with construction in 2006. The new US Energy Policy Act has also made provision for substantial financial assistance for the first few nuclear units ordered there. Nuclear investment has therefore become a reality again in other OECD countries, and this has prompted the idea that it could equally become reality here.

However, the uncertainties surrounding potential nuclear investment in the UK have not been materially changed by these events and perceptions, and they remain very substantial. First, neither of the two main contending reactor designs in UK conditions – the Westinghouse-BNFL AP1000 and the Framatome/Areva EPR – has yet been built anywhere in the world[2]. While both of these designs incorporate only incremental changes to designs

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1 Department of Trade and Industry, Our energy future - creating a low carbon economy, TSO, February 2003, Page 76..

2 As we note in Chapter 4, there are in principle two other potential candidates, but we have discounted them for the purposes of this analysis:

previously built (both are described by the industry as 'evolutionary') there are inevitably significant uncertainties involved because of the lack of any prior construction experience. The EPR has been chosen for both Finnish and French reactors, but it will be several years before these projects will significantly reduce uncertainties.

A further specific uncertainty here is that the relevant UK safety regulator, the Nuclear Installations Inspectorate (the NII), has not yet started to consider safety cases for either of these designs. When the NII considered the proposed design for the last UK reactor to be built (the Westinghouse PWR at Sizewell B) it required significant design changes that raised construction costs significantly. The evolutionary AP design aims to be more passively safe than the Sizewell design while the EPR concentrates mainly on trying to gain economies of scale by increasing unit size. The AP1000 has recently received generic safety approval from the US Nuclear Regulatory Commission (NRC). These factors may possibly make new reactor designs less subject to cost-increasing safety modifications than was the case for Sizewell B, but by definition this remains unknown at present.

Finally, the UK's history of both nuclear construction and large projects in general has by international standards been poor. This does not mean that a repeat of the Sizewell B experience is at all likely: Sizewell B has a total generating cost in today's money of over 6p/kWh[3] and no-one expects anything as expensive on any future nuclear project. There are several reasons to expect significant improvement, apart from the expectation that current reactor designs are expected to be simpler and require fewer material inputs and less on-site fabrication:

- Big-project management techniques have improved over the last fifteen years.
- There is likely to be a more competitive, international process for letting a nuclear construction contract.
- A consortium taking on a nuclear project would probably offer terms that are closer to a turnkey (fixed price) contract than the cost-plus contracts[4] that were characteristic of past nuclear construction.

As a future nuclear project would be in the private rather than the public sector, there is likely to be a closer fit between risk and consequence: in other words, the prime contractors will have better incentives to control costs because they will suffer greater consequences in profit terms if they fail to do so.

- Japan is constructing versions of the BWR and PWR that derive from GE and Westinghouse respectively but have been adapted by Japanese licensees. However, no Japanese manufacturer has ever tried to export its designs and this seems unlikely to change. The Advanced Boiling Water Reactor, already built in Japan and under construction in Taiwan, could be a contender for UK orders, but BWRs have never been seriously considered in the UK since 1965. Partly for the reason that BWRs tend to produce higher operator doses than other reactor types, it seems improbable that ABWRs would compete in the UK;

- The Candu heavy water reactor developed by AECL of Canada is often mentioned as a candidate for UK construction. However the design is significantly different from light water reactors (PWRs and BWRs) and the licensing process in the UK would probably be lengthy. For this reason CANDUs are 'outsiders' in any future competitive process.

3 Performance and Innovation Unit (PIU), The Energy Review, Cabinet Office 2002; Working Paper on the Economics of Nuclear Power, Table 1, Page 6.

4 A cost-plus contract means that the contractor can charge a client all costs incurred on a project plus a profit margin.

Vendors may be willing to sign more or less turnkey contracts for initial nuclear orders and this would offer some financial protection to utility purchasers of nuclear plant and their customers. But a willingness to absorb some risks on the part of vendors seeking market entry does not necessarily reduce risks: it re-allocates them, but will only reduce them to the extent that management incentives are imposed and are effective. And if the risks crystallise, vendors will not be willing to continue to absorb financial losses and would resort (as in the USA in the late 1960s and early 1970s, after similar early turnkey orders) to a more cost-plus contractual structure.

'Appraisal optimism' has been characteristic of many 'mega-projects' in the UK and elsewhere and cost forecasts for nuclear projects have been among the most optimistic. It is too early to be confident that such optimism has entirely dissipated even if private contractors may financially suffer the subsequent consequences of optimism more than their earlier public sector counterparts. The uncertainties are especially acute as any nuclear project in the UK would, as things currently stand, probably involve the construction of a design yet to be built anywhere in the world. This might not automatically lead to optimism, but given the commercial incentive for vendors to start creating a potentially large market which they would expect to be profitable in the longer term, optimism remains likely. And various kinds of public intervention that might be necessary to induce private sector investment in nuclear power (including guarantees of one kind or another, see section 7.2 below) could well weaken the link between optimism and consequential private sector financial loss. In other words, appraisal optimism is still a significant risk for future UK nuclear projects.

2.1. International ordering

We deal with recent international ordering patterns in more detail in Section 6.2 below. In summary however:

- Altogether 24 reactors are officially under current construction around the world, though only one of these, the Finnish EPR, uses a reactor design which is likely to be offered in the UK.
- In OECD Europe and North America, the only nuclear plant ordered in the last decade has been the Finnish EPR, on which construction started in late summer 2005.
- Nine of the 24 reactors were originally ordered before 1990, and are mostly of dated Russian design.
- The bulk of genuinely recent nuclear ordering has been in East and South Asia. The country with the largest and most consistent recent 'programme' is South Korea, using two main reactor types.
- China has ambitious plans (up to 30 reactors) for nuclear construction but currently only has two plants on order.
- India appears to have 8 plants being built (including 2 recent Russian-origin units) but there is some doubt about the commitment or capacity of India to complete these in a timely fashion.
- Commercial and regulatory considerations may rule that new nuclear power remains infeasible in the UK. If it does prove to be commercially feasible there are very many impacts, beyond those of commercial profitability, which will bear upon its welfare impact on the nation (or the world) as a whole. We list, in section 2.2, the most important

impacts, with a summary of the (very limited) extent to which we believe it is feasible to express each in monetary terms, and so incorporate quantitatively in "the cost of nuclear".

2.2. Clearly negative externalities

Three well recognised negative externalities are:

- Risk of radiation release from the nuclear plant, following an accident or intentional damage;
- Risk of radiation release from the nuclear waste, in the medium or perhaps very long term;
- Potential transfer of technology to nuclear weapons production.

These are all factors on which a considerable amount of quantitative and qualitative data is available, which needs to be considered by the government in weighing any policy decision about the acceptability of new nuclear generation. However, while they are all different in kind, none appear to us to be suitable for expressing explicitly in monetary terms.

Any increase in the prospective possible public sector financial commitment to waste storage that will arise from the new reactor should be valued as a cost to the economy, as should any other material public financial contribution to the plant.

2.3. Clearly positive externalities

Two well recognised positive externalities are:

- Reduced greenhouse gas emissions;
- Improved security of electricity supply.

These again are factors on which much data is potentially available. We doubt that it would be helpful to try to value improved security of supply explicitly in monetary terms. It should however be practicable to value the impact of greenhouse gas emissions, using an estimate of the marginal cost of restraining emissions to meet future expected emissions targets (and subject to any possible impact on renewable energy sources, as noted in section 7.2.3 below).

3. Components of Nuclear Power Costs

The analysis which follows is concerned principally with the costs of nuclear power in the context of single stations. In other words it does not consider any of the wider systemic costs that may be involved – for example the costs of connecting a nuclear station to the transmission network or the need, if a large unit is connected, for a minimum level of standby power to be available in case of a need to shut the plant down. In practice, this will not significantly distort any of the results, and in any case the great bulk of data available is of the 'single station' type.

The data we consider in this report generally contributes to an analysis of generating costs, generally expressed in terms of pence/kilowatt-hour or sometimes £/megawatt-hour. We do not generally provide a translation of cost components into generating costs, though for any given discount rate or cost of capital it is usually possible to do so. For example the assumptions used in the Royal Academy of Engineering report translate (at 7.5% discount rate) into a forecast generating cost of 2.2p/kWh for CCGTs, 2.3p/kWh for nuclear and higher numbers for wind power.[5] Given the uncertainties attaching to the basic data that contributes to these calculations – the main subject of the present report – such apparently definitive numbers should be treated with caution in the case of UK nuclear power.

A useful context for the presentation of nuclear power costs is an outline of the main cost components and their relative importance. Costs for nuclear plant can be divided into four main components:

- construction or capital cost;
- fuel costs;
- operations and maintenance charges; and
- 'back end' costs for waste and decommissioning.

The first three of these cost categories are common to all power plants. The fourth, 'back end' costs are in principle applicable to all power plant types, but in practice are only of significance for nuclear plants. In the nuclear case, such costs are handled differently in different analyses. Sometimes, waste costs are included within fuel costs, as the bulk of wastes arise from spent fuel (especially if there is a 'once-through' fuel cycle). In other cases, regulatory regimes insist that some or all back end costs – sometimes including waste costs - are covered by a segregated fund that the plant owner must build up to a specified level during the course of plant operation, and in these cases all back end costs may be identified separately.

The proportion of generating costs (generally expressed in p/kWh) represented by each cost component for each technology will vary according to a range of factors. In the nuclear case, expectations about the construction cost and the rate at which future costs and benefits are 'discounted' plus assumptions about back end costs cause the greatest variations. For fossil-fuel fired plant, where the cost of fuel is the dominant element, the cost components will vary according to expectations about future fuel prices.

Table 3.1 below presents some typical cost proportions for three generating technologies. Combined cycle gas fired power plants are included because they have been the dominant

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5 Royal Academy of Engineering, The Costs of Generating Electricity, March 2004, page 8.

technological choice for private investors since privatisation of the British electricity system in 1990. Wind power is included because it is becoming the predominant renewable technology. Table 3.1 assumes that the discount rate (reflecting a possible private sector cost of capital) is around 10% (real).

Table 3.1
Representative Proportions of Electricity Generating Costs (%)

	Nuclear	CCGT	Renewable (wind)
Construction or capital (including interest during construction)	60-75	30-40	85-90
Fuel	5-10	50-65	0
O&M	8-15	5-10	5-15
Back end	*	0	0

Source: adapted from International Energy Agency (2001) Nuclear Power in the OECD, Paris, p. 124

The asterisk in Table 3.1 against 'back end' costs – waste and decommissioning – reflects a number of uncertainties. First, costs are affected by the decision whether or not to reprocess spent fuel (its separation into plutonium, uranium and various waste streams), or alternatively to treat spent fuel as waste. The UK and France have been historically committed to reprocessing as a matter of public policy, though there are no plans to reprocess spent fuel from Sizewell B. It is now widely accepted that reprocessing adds significantly to costs – for instance an OECD study of 1994[6] suggested that reprocessing was at least twice as expensive as direct disposal of fuel. It is widely assumed that any future reactors in the UK would therefore not reprocess their fuel. Second, both decommissioning and especially waste management costs are highly uncertain because there is so little relevant commercial experience, and these costs could be high and stretch over hundreds of years. Their importance within the overall generating cost will also vary substantially according to assumptions about the rate at which such back end costs should be discounted. This means that it is difficult to give a representative figure for these back end costs. We can however say that these costs are likely to be very small as a percentage of generation costs.

There are many ways in which funding could be put in place for waste and decommissioning costs, including the possibility that substantial funds could be required at the start of the project – in other words an addition to capital cost. However common practice for privately–owned nuclear plants[7] is to require plant owners to cover back end costs by setting up a segregated trust fund (to guarantee availability of money when required) and then to allow the fund to accumulate by annual contributions for at least the expected plant lifetime, often 40 years. Investing the fund in safe stocks (e.g. Government bonds) allows the fund to earn an annual return in the region of 3% in real terms. However there is little international experience of commercial scale decommissioning and even less experience of 'final' costs

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6 OECD Nuclear Energy Agency *The economics of the nuclear fuel cycle*, Paris 1994

7 This is broadly the way in which British Energy were required to fund long-term decommissioning costs before the company got into financial difficulties.

for high and intermediate level waste. Past industry cost estimates in this area have tended to escalate steeply and could well do so again[8].

A calculation by BNFL in 2002 based on an expected decommissioning and waste cost of £365m yielded a cost of 0.014p/kWh at the conservative fund accumulation rate of 2% annually, or a contribution of well under 1% to total generating cost[9]. Even if the BNFL estimates of decommissioning and waste costs were to escalate by a factor of ten in real terms, this would still mean that the back end would cost around 0.14p/kWh and would contribute (all else equal) 5% of total generating cost. Private investors might still require Government guarantees – for instance to put a cap on private liability for back end costs – but the significance of the back end for total generating costs will still be very substantially less than capital costs, which are discussed in the next paragraph.

For nuclear power, construction or capital costs are the critical item because of their dominance – they are responsible for around two-thirds of generating cost. In present circumstances, the importance of capital costs is made even greater because greater uncertainty attaches to capital items than to fuel and O&M. There are two main reasons for this:

1. There is substantial real-world, operating data on both fuel and O&M costs from existing reactors. Fuel costs are low and stable: uranium is plentiful and the enrichment/fuel manufacturing industry is mature. O&M costs vary more across countries (partly depending on regulatory needs and reactor reliability) but they have generally been falling and have become more predictable. There are reasonable grounds for believing that both of these items are relatively stable and will take similar values in potential new reactors to those observed in currently operating plant;
2. Conversely there is a complete absence of recent, real-world data on the capital costs of reactors of the kinds likely to compete in the UK. Indeed no reactors of the type likely to compete in the UK have yet been built anywhere. Such data as are available are from a very narrow range of primary sources and refer in all but one case to paper-based or feasibility studies. Further, the history of cost estimation for large projects such as nuclear power stations is characterised by substantial optimism.

One other relevant piece of data – operating performance of reactors – is important because it translates cost/kW into cost /kWh. Good operating performance makes the capital cost per kWh low, and vice versa. Recent experience in the UK, USA and through much of the world is that operating performance of reactors has improved in recent years and has become more stable. It seems reasonable to expect that the designs of reactors that might compete in the UK will be able to reproduce the operating performance of most reactors in Europe and North America (around 85% availability or better).

The clear implication of this analysis is that capital costs, and associated construction times, are by a long way the most important element in the generating costs of any future nuclear plant in the UK, and they receive correspondingly the greatest attention in the analysis below of other studies.

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8 M. Sadnicki and G. MacKerron *Managing UK Nuclear Liabilities* SPRU, University of Sussex, 1997, especially Chapter 5.

9 K Hesketh, *BNES Seminar Reactor Economics*, BNFL Research and Technology, 15 May 2002

The level of uncertainty for CCGT and renewable costs is less than for nuclear. For renewables, construction costs dominate and are fairly predictable for onshore wind due to significant recent experience. For offshore wind and other renewables, more uncertainty attaches to construction costs and it is always necessary – to get specific generating costs - to know something about site characteristics. For gas, fuel is the significant uncertainty as gas prices are uncertain in the future.

4. Data Sources and Quality

4.1. Reactor types

Before discussing data sources, it is worth briefly reviewing the types of reactor that might be built in the UK in the next few years. As mentioned above, all but one of current worldwide nuclear orders use technology that is unlikely to be used in the UK. It is worth noting that more radical reactor designs widely promoted by the nuclear industry in recent years – the most prominent of which is the small-scale Pebble Bed Modular Reactor (PBMR) – are many years from being capable of feasible licensing and so are not considered in the analysis below.

- Seven current orders (two in China, two in India) use variants of a Russian WWER, pressurised water reactor design, and one in Russia uses the RBMK design, similar to Chernobyl. There has never been an attempt to license Russian designs in OECD Europe or North America, and there is no expectation that any attempt will be made in the future. The Argentine PHWR and Indian FBR designs are even more improbable.
- Japan is constructing versions of the BWR and PWR that derive from General Electric and Westinghouse respectively but have been adapted by Japanese licencees. No Japanese manufacturer has ever tried to export its designs and this seems unlikely to change. The Advanced Boiling Water Reactor, already built in Japan and under construction in Taiwan, could be a contender for UK orders, but BWRs have never been seriously considered in the UK since 1965. Partly for the reason that BWRs tend to produce higher operator doses than other reactor types, it seems improbable that ABWRs would compete in the UK.
- AECL of Canada has developed variants of a pressurised heavy water reactor (Candu) for many years and has publicly expressed their desire to compete in the UK market. CANDU designs of close-to-current-vintage have been built in Korea and it is conceivable that CANDU designs could be licensed in the UK. However it seems unlikely that CANDU designs would seriously compete in the UK market, especially as the technology licensing process would take substantially longer than for the PWR designs mentioned below.
- The Pebble Bed Modular Reactor (PBMR), under development in South Africa and with BNFL as a minority partner has been much publicised as a more radical alternative. The PBMR is a development of an earlier German high temperature reactor design and has several novel design features, including helium coolant directly driving a gas turbine, and small spherical fuel elements. It was originally hoped to complete a demonstration plant by 2003, allowing commercial ordering soon after. However there have been delays to this timetable, most recently the legal revocation of an earlier environmental approval to construct the demonstration plant. Such a plant is now unlikely to be complete before 2010 at the earliest. Given a need both to accumulate operating experience on this plant and to gain safety regulatory approval in the UK, PBMR technology is unlikely to be available in the UK until close to 2020. Costs are necessarily uncertain, but the expected cost of the demonstration plant has itself escalated by a factor of around seven

since 1999[10]. In these circumstances it is impossible to know what the costs would be for a commercially available, fully licensed, PBMR.

This leaves the two obvious front-runners for future reactor types in the UK, the AP1000 pressurised water reactor (AP1000) developed by Westinghouse/BNFL and the European Pressurised Water Reactor (EPR), developed by Framatome/Siemens (now offered by Areva, Framatome's parent). Both are developments (often called 'evolutionary') from Westinghouse PWR technology: in the case of the AP1000, around 1100MW, the changes involve more passive safety systems and simplified design; and in the case of the EPR, the changes mostly involve scaling up to 1600-1750MW unit size to gain economies of scale. Neither of these reactors has yet been built anywhere in the world, though the first EPR started construction in Finland in late summer 2005 and France will probably start a second unit at home in 2006. Both technologies have established regulatory clearance in important markets: the AP1000 in the USA, and EPR in Finland and France.

The important conclusion from the above discussion is that the two leading competitors for UK construction have not yet been built anywhere in the world, so that experience from current orders and recent completions overseas are of little relevance to the UK.

4.2. Data sources

The first and most important point about data sources on the costs of new construction is that there are very few that relate directly to the UK. In practice only three studies aim to provide data directly relevant to the UK and these are the DTI's views (2005)[11], the 2004 Royal Academy of Engineering report and the 2005 Oxera study.[12] The PIU study of 2002[13] also provided some data on nuclear costs without being able to disclose confidential details from the nuclear industry of expected capital costs. The PIU figures have been superseded by more recent developments. The New Economics Foundation also provide views on future nuclear costs in the UK[14] but these are not based on any recent data and are inferential in nature. The first three studies are therefore the only sources of cost data that currently and directly apply to UK conditions.

The touchstone of data quality (and possible bias) is the material that each report provides on nuclear capital costs. The DTI capital cost figures are reported to derive from 'industry sources and modelling work'. The origin of the Oxera figures is not made clear, but may well, by arithmetic interpolation, be based on the DTI figures. The RAE sources are ambiguous: the main report suggests that its data are directly derived from the MIT study into US nuclear economics,[15] while a complementary presentation on the study by RAE's contractors (PB Power) suggests that the capital costs are based on reported Finnish EPR costs. Whichever the basic source may be, each derives from an uncritical translation of overseas capital cost

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10 S. Thomas *The economic impact of the proposed demonstration plant for the Pebble Bed Modular reactor design,* PSIRU, University of Greenwich August 2005, pp. 20-22.

11 Department of Trade and Industry, 2005

12 Oxford Economic Research Associates, Financing the nuclear option: modelling the cost of new build, Oxera, June 2005

13 Performance and Innovation Unit (PIU) The Energy Review, Cabinet Office 2002; Working Paper on the Economics of Nuclear Power.

14 New Economics Foundation, Mirage and oasis: Energy choices in an age of global warming, NEF, June 2005

15 Massachusetts Institute of Technology, The Future of Nuclear Power: an interdisciplinary MIT study, MIT, 2002, esp. Chapter 5

expectations to UK conditions. The DTI sources leave no clear audit trail, but while 'modelling' cannot independently generate capital cost figures, it seems reasonable to infer that the DTI figures used are based on 'industry sources'. Such sources are presumably from the nuclear industry and given that Westinghouse is currently owned by BNFL (a UK state-owned company) it seems likely that the source of the data is Westinghouse. Whether or not this is the case 'industry sources' have incentives - especially in a pre-contractual situation - to offer a view of nuclear costs that will be optimistic. It is not clear whether DTI have amended the industry figures to correct for any perceived bias or optimism.

There are many more sources of economic data from overseas sources. There are obvious difficulties in transposing these to UK circumstances. The reasons for this are several:

- Where different reactor technologies from those likely to be used in the UK are being costed, there will be no direct application to the UK.
- It is not usually helpful to translate costs denominated in other currencies directly into sterling costs, because the industrial structures, labour conditions and regulatory regimes vary widely between countries. More generally the prices of non-tradable inputs (especially labour) are highly variable. Attempts have been made in some studies to correct for some of these problems by using purchasing power parity exchange rates rather than current or official exchange rates but these can only be partially successful – if only because of the differences in regulatory regime, which in turn influences design details.

There are three other problems in data comparisons, not applying only to overseas estimates:

- The scope of cost estimates, especially for capital costs, may vary widely and cannot always be discerned. Some estimates include financing costs[16], owner's costs, first-of-a-kind costs, and others may exclude some or all of these, rendering comparisons inaccurate. Allowances for contingencies are variable and are not always explicit.
- The price basis for some estimates is not always clear – different estimates may be denominated in prices of different years and the price base is not clear in all studies.
- Some studies quote figures for the first reactor of a particular technology while others quote only 'nth' of a kind. Given that the nuclear industry universally expects costs of later units to fall substantially with experience of building identical units, this can make a substantial difference to estimates.

With these caveats in mind, some international sources can be reviewed. The NEA and IEA provided data in 2005[17] for notional future nuclear plants in 11 countries (not including the UK – data from the UK, with costs quoted in Sterling, comes from the Department of Trade and Industry but is not incorporated into the main body of the report), while easily the most thorough and comprehensive studies come from the USA. Three studies are especially noteworthy:

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[16] For a publicly financed project, financing costs are generally irrelevant to investment appraisal, as they are subsumed in a (higher) discount rate derived on other criteria. However, with private financing, financing costs are a social cost to be included, no less that the cost of materials. In practice this is normally done by including, in the costs to be recovered from sales, capital charges that would give a rate of return equal to the weighted average cost of capital.

[17] Nuclear Energy Agency / International Energy Agency, Projected Costs of Generating Electricity, OECD, 2005, esp. p149-152

- Scully Capital (2002) provided for the USDoE a 'business case' for new nuclear build in the USA[18], with cost data plus much detail on possible financing schemes and Government assistance.
- MIT conducted a major and much-publicised study in 2003 on nuclear power in general, including economics.
- The University of Chicago conducted another study for the US DoE in 2004[19], on the overall economics of possible new nuclear power plant in the USA, with significant detail on the applicable cost of capital.

The most interesting question then becomes the source of these reports' capital cost data. In the case of Scully, the main source appears to be Westinghouse: Scully consulted mostly industry sources and quotes figures based on the AP1000. MIT sources for capital costs are 'consistent' with earlier figures from the USDoE EIA (themselves derived mainly from industry sources) and from the OECD. MIT however correct for some possible appraisal optimism by adding a 10% contingency and a further 10% allowance for 'optimism' to their source figures. The University of Chicago study uses figures for capital costs for ABWRs, Candus, AP1000 and a Framatome BWR design. The sources for these data appear to be the USDoE, AECL, Westinghouse and, possibly, Framatome. It seems unlikely that Chicago significantly amended these data before using them in its analysis.

An Areva (France) study on the costs of the EPR[20] gives some relevant data on the assumption of a 10-reactor programme. Given that Areva is a vendor with interests in selling into the UK market its cost estimates need to be treated with some caution as the vendors' commercial incentive is clearly to estimate optimistically.

The most interesting overseas cost case is that of Finland, the only OECD Europe country to have a live order. This leads to the possibility that capital cost data, while still a forecast, might be more commercially based than relying on than paper studies, mostly from vendors. However the Finnish study pre-dates the recent order and deals in a smaller reactor size. There is also a single piece of data giving a single and rough capital cost figure, based on the turnkey (fixed price) contract and for the recent Finnish order, but its scope is not clear (see section 6.3 below). There are other sources which quote some cost figures for countries such as China, Japan and Korea but their value for the UK is dubious. All are using technologies unlikely to be offered in the UK and all have cost and industrial structures so different from those of the UK that translation of their data into UK terms is of very limited obvious value.

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18 Scully Capital, Business Case for Early Orders of New Nuclear Reactors, 2004, esp. p5-5

19 The University of Chicago, The Economic Future of Nuclear Power, August 2004

20 EPR Background and its Role in Continental Europe, AREVA Corporate Strategy Department, Didier Beutier, Westminster Energy Forum Thursday 23rd June 2005.

5. Analytical Comparisons of Cost Data

The main sources that are compared here are those of the DTI, RAE, Oxera and a limited number of international studies: the NEA/IEA report, a Finnish report[21], an Areva study and three studies from the US. Numbers are reported in original currencies as well as sterling because of the problems of uncritically using exchange rates for this purpose.

The main focus here is on capital costs for reasons already well-rehearsed. However the other components of cost are dealt with first, leaving the most critical cost component for more detailed analysis.

5.1. Fuel, O&M and back-end costs

As argued earlier, these costs are relatively unimportant in determining the status of nuclear power economics. In addition there are wide-ranging, fairly reliable data on these costs from operating reactors, and there seems no reason why – despite the relative novelty of potential new UK reactors – such performance should not broadly indicate future performance. Back end costs are more complex and final costs, especially for wastes, are highly uncertain. But because these costs are postponed well into the future, even low discount rates mean that even quite large variations on decommissioning and waste costs will have little impact on overall generating costs.

Table 5.1 compares quoted costs for fuel and O&M and treatment of back end costs across the various studies.

[21] Tarjanne and Rissanen, Nuclear Power: Least-Cost Option for Baseload Electricity in Finland, The Uranium Institute 25th Annual Symposium, 30 August – 1 September

Table 5.1
Different Cost Estimates: Fuel, O&M, and Back-end

	Fuel cost	O&M Cost	Back-end
DTI	Na	Na	Na
RAE	0.4p/kWh	0.45p/kWh	Decommissioning costs within capital cost
OXERA	0.3p/kWh	035p/kWh	£500m fund at 40 years
NEA / IEA	0.28-1.18USc/kWh	46-108USD/kW	Decommissioning included in construction cost
Areva	0.44ec/kWh	€51/kW	Decommissioning €6.5/kW
Tarjanne and Rissanen	0.1ec/kWh	0.34ec/kWh	Na
Scully	0.5USc/kWh	0.5USc/kWh	$400m fund at 40 years
MIT	0.15USc/kWh (fuel plus O&M)		Na
Chicago	0.3USc/kWh	0.56USc/kWh	$300m fund

Source; DTI (2003) , Royal Academy of Engineering (2004) p42, Oxera (2005) p3, NEA (2005) p44, Areva (2005) p16, Tarjanne and Rissanen (2000) p8, Scully Capital (2004) p5-5, MIT (2002) p43 and The University of Chicago (2004) p.
For most studies it is not possible to tell which year's prices are used in setting out cost numbers. Oxera is one exception, quoting a 2005 price base. For the other studies a reasonable guess is that they may be using the prices of the year of publication.

The UK aggregate figures for fuel and O&M are 0.85p/kWh from RAE and 0.65p/kWH from Oxera. The French and Finnish figures are broadly at the low end of this range. The US fuel costs are broadly comparable to the UK figures, while the O&M costs tend to be higher for specifically US regulatory reasons. Fuel costs have been broadly stable or falling for some years. The bulk of fuel costs are for uranium conversion and enrichment and fuel fabrication and these are stable and mature industries. Uranium itself accounts for only some 10% of the cost of nuclear fuel.

O&M costs vary by country but tend to be low where operating performance is good (high availability means few breakdowns and repairs) and have tended to fall as the periods between reactor servicing have lengthened and outage periods reduced. In UK conditions, the 0.65p/kWh to 0.85p/kWh range from RAE and Oxera will probably span the range of probable future costs in these areas: the chances of significantly exceeding 0.85p/kWh seem small.

5.2. Capital costs, construction time and operating performance

While capital costs are the headline issue here, both operating performance and construction time are also potentially important. Short construction times tend to be associated with low costs, but even where there is limited correlation between time and cost, extended construction times raise total capital costs by significantly increasing financing costs – interest during construction on funds tied up increases directly with project length. Construction times in the studies examined here (when specified) are generally in a narrow range: RAE 5 years;[22] NEA/IEA 5-10 years;[23] Areva 5.5 years;[24] Scully 5 years;[25] MIT 5 years;[26] Chicago 5.3 – 9.3 years.[27] The definition of construction time is not always clear. Ideally it should be from start on site to commissioning, with substantial pre-construction periods applying in all cases.

Five years is the minimum construction time assumed in the studies examined, while both NEA/IEA and Chicago (reporting in both cases across much international experience) contemplate significantly longer periods. Construction times of five years and less have been achieved in East Asia in recent years (Japan and Korea) on different designs. While 5 years may be optimistic, six years is probably a reasonable expectation for the UK. The impact on overall generating cost of a year's difference compared to six years, in either direction, would be small – although if delays are correlated with capital cost overruns, the impact via capital costs could be substantial.

Operating performance – measured as load factor or proportion of the year that a plant produces rated output – is important because higher output stretches a given capital cost over more units and thus reduces capital cost per kilowatt hour. Operating performance of UK gas-cooled reactors, especially the newer designs of AGR, has been poor by international standards. Performance has however substantially improved in recent years and because poor earlier performance was largely technology-specific. It is in any case a largely irrelevant guide to future performance in PWR-related technologies. The one UK PWR at Sizewell B has had good operating performance since commissioning in 1994 (averaging around 84%). Worldwide, operating performance has also been higher and more consistent since the early 1990s. In the range of operating performance levels now commonly seen worldwide (rarely below 80% and sometimes exceeding 90%) the impact of variation on overall nuclear economics is quite limited.

In the studies examined here assumptions about load factors (where specified) are as follows: DTI 85%[28]; RAE 85%[29]; Oxera 95%[30]; NEA/IEA 85%[31]; Areva 90.3%[32]; Finland 91%[33]; Scully 90%[34]; MIT 75%-85%[35]; Chicago 85%[36]. The Oxera figure is probably

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22 Royal Academy of Engineering, The Cost of Generating Electricity, RAE, June 2004, p41

23 Nuclear Energy Agency / International Energy Agency, Projected Costs of Generating Electricity, OECD, 2005, p43

24 EPR Background and its Role in Continental Europe, AREVA Corporate Strategy Department, Didier Beutier, Westminster Energy Forum Thursday 23rd June 2005 p16

25 Scully Capital, Business Case for Early Orders of New Nuclear Reactors, 2004, p5-5

26 Massachusetts Institute of Technology, The Future of Nuclear Power: an interdisciplinary MIT study, , MIT, 2002, p43

27 The University of Chicago, The Economic Future of Nuclear Power, August 2004, p2-13

28 Department of Trade and Industry,

29 Royal Academy of Engineering, The Cost of Generating Electricity, RAE, June 2004, p42 and calculated utilising DCF analysis

30 Oxford Economic Research Associates, Financing the nuclear option: modelling the cost of new build, Oxera, June 2005, p3

31 Nuclear Energy Agency / International Energy Agency, Projected Costs of Generating Electricity, OECD, 2005, p152

32 EPR Background and its Role in Continental Europe, AREVA Corporate Strategy Department, Didier Beutier, Westminster Energy Forum Thursday 23rd June 2005 p16

33 Tarjanne and Rissanen, Nuclear Power: Least-Cost Option for Baseload Electricity in Finland, The Uranium Institute 25th Annual Symposium, 30 August – 1 September p2

34 Scully Capital, Business Case for Early Orders of New Nuclear Reactors, 2004, p5-5

optimistic as it exceeds any consistent historic world performance. Owners of new plant will generally aim for around 90% but this would be an optimistic number in appraising an investment in a technology not yet built anywhere in the world, and bearing in mind that operating performance may take a few years to 'settle down'. A figure of 85% would seem a fair expectation of a future UK reactor.

5.2.1. Capital costs

As argued earlier the economic status of nuclear power turns largely on capital cost. The history of cost control in the UK has been poor. All first generation AGRS over-ran significantly, and the Sizewell B PWR over-ran by at least 35% in real terms, ending up (in today's money) at little short of £3bn. for a 1175 MW reactor (well over £2000/kW). But this history is probably a poor guide to prospective future performance for reasons outlined in Section 1.

On the other hand, as section 4 makes clear above, the data available on this most critical cost component is very thin. It suffers in the following ways:

- None of the UK-related capital cost data appears to have been calculated for UK conditions: it appears, sometimes quite explicitly, to be a direct translation from overseas data, all for reactors not yet built and therefore paper-based.
- A significant part of the explanation for the differences in capital cost between different studies, and in some cases the differences in quoted costs within the same study, is variation in assumptions about the number of reactors built. A programme of essentially identical reactors, usually a minimum of 8 or 10, is expected to lead to significant reductions in average capital cost per kW as a result of learning plus batch production rather than one-off component ordering. For instance recent Korean data suggests that the seventh and eight units in a series may have capital costs per kW as much as 28% below the costs of units 1 and 2 in the series.[37] Much confusion results from the fact that not all studies make clear whether or not a single reactor or a programme is being assumed. To reap the full benefits of learning requires a commitment to a scheduled programme of identical reactors at the first decision point. This largely explains the argument made by the UK nuclear industry in 2001 that commitment to a programme of 10GW of reactors would be necessary.[38] It also, when combined with the large unit size of potential new reactors is a source of inflexibility: low cost can only be achieved if very large commitments are made.
- All of the data is traced back to industry sources, usually reactor vendors, and the number of these sources is very few. This is probably inevitable when discussing not-yet-built reactors, but it does little for confidence in the balanced nature of the numbers. Reactor vendors inevitably and legitimately have an interest in presenting costs in a way that maximises their chances of commercial success: their incentive structure inevitably leads them towards relatively optimistic estimates, especially in advance of contractual commitments. Some of the original costs quoted by vendors have been augmented by

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35 Massachusetts Institute of Technology, The Future of Nuclear Power: an interdisciplinary MIT study, MIT, 2002, p43

36 The University of Chicago, The Economic Future of Nuclear Power, August 2004

37 R. A. Matzie, Building New Nuclear Plants to Cost and Schedule – an International Perspective, presentation to RAE seminar, September 29 2005, p. 5

38 British Energy, Replace nuclear with nuclear: Submission to the Government's Review of Energy Policy, British Energy, 2002, p16-23

to allow for optimism (explicitly in the MIT study, and probably in the case of the higher DTI figure) but the allowances for optimism appear to be relatively limited compared to the possible scale of cost overruns on large and substantially novel projects. In some cases, no such adjustments have been made (e.g. Scully). Appraisal optimism' is widespread across large infrastructure projects and many countries. For example the World Bank studied capital cost results compared to forecasts across a wide range of its own energy projects. It concluded that the error in original estimates was in well over 90% of cases studies in the direction of initial optimism and that more complex projects (mainly hydro electricity) tended to be more optimistic than simpler and less expensive projects.[39] More recently and more widely Flyvbjerg et al (2003)[40] has offered wide-ranging analysis of the pervasiveness of appraisal optimism across many large and complex projects. The basic argument that project promoters, especially when they will not suffer the full consequences of optimism, will gain advantage from a tendency to under-estimate costs and risks, is straightforward.

- Where vendors enter into contracts for reactor sales, data may well become more realistic because vendors may well suffer losses if they contract at too low a price. However there are important qualifications here: only one such contract exists, for Finland, and the data released is aggregative and rounded; vendors may well pursue ‘loss-leaders’ on early contracts in the expectation of later, more profitable contracts as learning takes place; and the likelihood of various kinds of Government assistance, (e.g. including guarantees of the kind now being offered in the USA) needed to stimulate private nuclear investment may well loosen the link between cost over-runs and vendor losses. Finally ‘turnkey’ contracts’ are unlikely to indemnify clients against all risks, and in the case of the Finnish contract there is no public information, for example, on the existence and scope of any ‘force majeure’ clauses.
- While all the studies quoted include financing costs in their overall calculation of generating cost, it is not always clear whether or not the costs in Table 5.3 are ‘overnight’ costs[41] (excluding financing) or are total costs (including financing, which involves assumptions about construction time, debt/equity structure and cost of capital).

This means that while the capital cost figures quoted in Table 5.2 below may well represent a range of achievable costs if all goes well, they do not capture the real uncertainties that exist in current UK circumstances. The RAE approach of suggesting a plus or minus 25% range for capital costs seems misguided. In current circumstances risks are not equally distributed about the average: the distribution is heavily skewed to a higher probability of overrun than cost savings. There really is no way of knowing a *realistic* capital cost of a new UK reactor and the uncertainty range is very pronounced

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39 R. Bacon et al. Estimating Construction costs and Schedules, World Bank technical Paper no. 325, Washington DC 1996, esp. pages 1 and 28

40 Flyvbjerg et al, Megaprojects and Risk, Cambridge University Press, 2005

41 Overnight costs are the sum of all costs without considering time. They are expressed as if all incurred instantly, or ‘overnight’. ‘Total’ costs in this context is the sum of all expenditures incurred in a real project, including the interest costs incurred on capital tied up during construction.

Table 5.2
Different Cost Estimates: Capital Costs

	Capital costs/kW	First/nth unit	Included/ Excluded
DTI	£1,070-1,400	Not known	Not known
RAE	£1,150	Probably nth	Not clear
OXERA	£1,150-£1,625	£1,625 first £1,150 nth	Includes 30% contingency for first reactor, licensing, public enquiry, start-up costs
NEA / IEA	$1100-2500	Probably variable	Overnight costs only
Areva	€1,252	Nth	Includes start-up costs
Tarjanne and Rissanen'	€2160	First	Not known
Scully	$1,000-1,600	$1,600 first/ $1,000 nth	Appears to exclude owner's cost/contingency. No financing included
MIT	$2,000	Not specified	Includes adjustments of 10% for contingency plus 10% for optimism
Chicago	$1080-1980	Variable according to estimate	Excludes financing costs. Owner's costs included, plus first of a kind engineering costs for higher estimates

Source; DTI (2003), Royal Academy of Engineering (2004) p41, Oxera (2005) p3, NEA (2005) p151, Areva (2005) p15, Tarjanne and Rissanen (2000) p8, Scully Capital (2004) p5-5, MIT (2002) p43 and The University of Chicago (2004) p1-8.

Note: For most studies it is not possible to tell which year's prices are used in setting out cost numbers. Oxera is one exception, quoting a 2005 price base. For the other studies a reasonable guess is that they may be using the prices of the year of publication.

Many of the studies quoted above provide estimates of the overall generating cost of electricity using their own input assumptions. Other studies provide an estimate of the generating cost in terms of cost/kWh and in such cases comparisons can be made with the costs of other technologies. Some studies, however, provide an estimate of the internal rate of return at an expected sales price. This is then compared to the expected cost of capital in order to judge the viability of the investment. This can be useful in terms of judging project profitability and commercial feasibility, but it does not help if one objective is to compare nuclear generating costs to the expected generating costs of other technologies.

Because published studies do not show the precise method by which different input costs are translated into generating costs, and because the assumptions made will vary and be of differing methodological quality, it is not possible in this report to evaluate whether or not the overall calculations are robust, and this in turn means that comparisons between the overall results of different studies are also problematic.

However it may be useful to present these overall results from the various studies to show the variability of results. There are several causes of variations which, in the absence of access to individual study modelling procedures, cannot be precisely attributed. Obvious causes of variations are, as would be expected from earlier analysis, differences in the assumptions about capital costs, and whether the first, average, or 'nth' unit is being considered. In addition, significant differences will undoubtedly be due to differences in assumptions about discount rates and/or the cost of capital (including different specific financing assumptions). Of the six sets of results presented below from the studies examined, three use a traditional 'levelised' form of calculation. This provides an annualised cost per kilowatt hour and uses a standard discount rate or cost of capital. It is the method often used by monopoly utilities facing a relatively stable future economic environment. The other three studies make explicit assumptions about financing (e.g. debt/equity ratios, expected return on each) and these, depending on the accuracy of the financing assumptions, are more applicable methodologically to private sector decision-making.

The results from the six studies are shown in tabular form below. It is clear that even within a single jurisdiction (the USA) there remain wide divergences between cost expectations, determined significantly by methods of generating cost calculation as well as differences in basic input assumptions such as capital costs.

Table 5.3
Overall Cost Estimates from Six Studies

Study	**Method**	**Assumption about no. of units built**	**Central Results**	**Sensitivity/ Range**
MIT	Levelised	No clear, poss. 1st	6.7 USc/kWh	4.9c-7.9c
RAE	Levelised	Not clear	2.26p/kWh	2.44p
NEA/IEA	Levelised	Not clear	3 USc-5USc/kWh	
Chicago	Levelised	1st unit	6.2 USc/kWh	5.2c-7.1c
Scully	Levelised	1st unit	3.8-4.2 USc/kWh	3.4c-3.7c
Oxera	Levelised	1st unit	Produces internal rate of return of 8%-11% (nominal, while market may need 14%-16%).	10.6%-13.6% (8th unit)

6. International Case Studies

In this section we set out the information available on international nuclear power projects under construction or planned and available cost forecasts for each country. While the objective is to give an overview of potential comparator projects for the UK, the relevance of different countries' experience is clearly very different. Data on the more potentially relevant costs have already been included in Sections 4 and 5 above. Here we set out international experience in more detail. In two cases (Finland and China) we provide more detailed information on projected plant costs and financing mechanisms.

6.1. Making International Comparisons

In comparing international examples we must be aware of the differences in plant performance between countries. One obvious difference is the use of different types of technology and size of reactor. Table 6.2 includes information on both of these variables for each plant planned and under construction.

However, even where different countries construct plants using the same technology and a similar unit size the performance of the reactor may differ. Table 6.1 shows three indicators of performance for eight countries currently constructing plants, plus the UK and France. The energy availability factor indicates the ratio of energy produced by the unit relative to the maximum amount of energy the unit could produce. The unit capability factor reflects effectiveness of plant programs and practices in maximising available electrical generation, and provides an overall indication of how well plants are operated and maintained. Where, as in the case of India, energy availability falls well below unit capability, this may be due to transmission system problems, in other words an inability to transmit available power from the power station to customers. Finally, the unplanned capability loss factor reflects the effectiveness of plant programs and practices in maintaining systems available for safe electrical generation.

Table 6.1
Comparison of UK and Countries with Reactors under Construction

Country	2004 Energy Availability Factor (%)	2004 Unit Capability Factor (%)	2004 Unplanned Capability Loss Factor (%)
UNITED KINGDOM	**74.2**	**74.6**	**9.4**
FINLAND	93.3	93.4	1.2
France	81.4	83	5.3
ROMANIA	89.1	89.4	2.9
ARGENTINA	89.2	89.2	3.5
CHINA	84.3	84.5	3.8
UKRAINE	81	85.1	1
INDIA	70.8	83.4	1.4
RUSSIAN FEDERATION	72.4	75.4	3.1
JAPAN	67.7	67.8	13.3

Source: IAEA, Power Reactor Information System, 2004. Note: Figures are cumulative factors from 2002-2004 where applicable.

The indicators represent the performance of each country's existing reactors between 2002 and 2004. As is evident from the table, there is strong variation in every indicator between countries. This reflects variations in technology and performance. For example, existing reactors in the UK are based on AGR and Magnox technology whilst most other European reactors are variants of water reactors.

Although these indicators do not necessarily reflect accurately differences in performance of future reactors, they do illustrate the difficulties in drawing conclusions using international comparisons based on existing plants with varying technologies.

6.2. Plants under Construction and Planned

Table 6.2 shows plants under construction globally as at September 2005, and Table 6.3 shows possible nuclear plants order in the next 2-3 years.

Table 6.2
Nuclear Plants under Construction, 2005

Country	Plant Name	Type of Reactor	Vendor	Net Capacity	Construction Started	Estimated Commercial Operation
India	KAIGA	Candu	India	202 MWe	30/03/2002	31/03/2007
India	KAIGA	Candu	India	202 MWe	10/05/2002	30/09/2007
India	KUDANKULAM	WWER	Russia	917 MWe	31/03/2002	31/12/2007
India	KUDANKULAM	WWER	Russia	917 MWe	04/07/2002	31/12/2008
India	MADRAS	FBR	India	470 MWe	23/10/2004	N/A
India	RAJASTHAN	Candu	India	202 MWe	18/09/2002	31/08/2007
India	RAJASTHAN	Candu	India	202 MWe	20/01/2003	28/02/2008
India	TARAPUR	Candu	India	490 MWe	12/05/2000	31/01/2007
Russia	BALAKOVO	WWER	Russia	950 MWe	01/04/1987	N/A
Russia	KALININ	WWER	Russia	950 MWe	01/08/1986	N/A
Russia	KURSK	RBMK	Russia	925 MWe	01/12/1985	N/A
Russia	VOLGODONSK	WWER	Russia	950 MWe	01/05/1983	N/A
Taiwan	Lungmen 1	ABWR	GE	1300 Mwe	1999	2009
Taiwan	Lungmen 2	ABWR	GE	1300 Mwe	1999	2010
China	TIANWAN	WWER	Russia	1000 MWe	20/10/1999	N/A
China	TIANWAN	WWER	Russia	1000 MWe	20/10/2000	N/A
Japan	HIGASHI DORI	BWR	Toshiba	1067 MWe	07/11/2000	01/10/2005
Japan	TOMARI	PWR	Mitsubishi	866 MWe	18/11/2004	01/12/2009
Ukraine	KHMELNITSKI	WWER	Net Capacity	950 MWe	01/03/1986	N/A
Ukraine	KHMELNITSKI	WWER	Net Capacity	950 MWe	01/02/1987	N/A
Finland	OLKILUOTO	PWR	Framatome	1600 MWe	12/08/2005	2009
Iran	BUSHEHR	WWER	Russia	915 MWe	01/05/1975	01/12/2006
Romania	CERNAVODA	Candu	AECL	655 MWe	01/07/1983	01/03/2007
Argentina	ATUCHA	PHWR	Net Capacity	692 MWe	14/07/1981	N/A

Source: IAEA, Power Reactor Information System, Last updated on 2005/09/1 and Steve Thomas, The economics of nuclear power: analysis of recent studies, July 2005, PSIRU, Page 6.

Table 6.3
Possible Nuclear Plants orders in the next 2-3 years

Country	Site	Bidders	Need	Possible order date	Forecast completion
China	Sanmen	Areva (EPR), BNFL/Westinghouse (AP1000), Russia (WWER-1000)	2x1000MW	2005/06	N/A
China	Yangjiang	Areva (EPR), BNFL/Westinghouse (AP1000), Russia (WWER-1000)	2x1000MW	2005/06	N/A
France	Flamanville 3	Areva (EPR)	1x1600MW	2006	2012
Korea	Shin-Kori 1&2	Korea (KSNP)	2x1000MW	2005	2010, 2012
Korea	Shin-Kori 3&4	Korea (APR-1400)	2x1400MW	2006	2012, 2013
Japan	Tsuruga 3&4	Mitsubishi (APWR)	2x1500MW	2006	2014

Source: Steve Thomas, The economics of nuclear power: analysis of recent studies, July 2005, PSIRU, Page 6.

The following sections present published estimates of the costs of nuclear power plants in each of the countries which are currently constructing new plants. The costs presented include constructions costs, operation and maintenance costs and fuel costs. Other costs such as licensing costs and back end costs are not always included. However, they may be very large.

Where possible we report the discount rate used to calculate costs estimates and in a number of cases we show the impact of variation of the discount rate on estimates. Overall, the impact of the discount rate is important. For example, doubling the discount rate (from 5-10%) on an estimate of French construction costs has the effect of increasing construction costs from $13.91/MWh to $27.50MWh see Table 6.5. Chapter 7 and Appendix A discuss further discounting and the cost of capital.

6.2.1. India

India has the largest number of plants under construction by a long way. However, Indian plants are predominantly built according to a 1960s Canadian design, as India's nuclear bomb testing in the 1970's resulted in a severing of communication with all western suppliers.[42] For example the PHWR unit under construction at Tarapur was developed indigenously from the 220 MW (gross) model PHWR, ten of which have been operating for up to 21 years.[43]

The exception is the two largest construction projects underway in India at Kudankulam. The two VVER-1000 (V-392) reactors are being supplied by Russia, under a Russian-financed US$3 billion contract. The units are being built by NPCIL and will be commissioned and operated by it under safeguards.[44]

The age and type of reactor design makes Indian plants generally a poor comparator for new plants being built in the UK.

<u>Forecast Costs</u>

Table 6.4 illustrates the forecast generation costs of two 500MW PHWR reactors which were planned in 1996. The costs are of the same order of magnitude as forecasts for projects in France during the same period and marginally more than those in Finland.[45] However, more up to date forecasts for Indian nuclear generation costs are not available.

Table 6.4
Projected Indian Generation Costs under Varying Discount Rates

	Investment $/MWh	O&M $/MWh	Fuel $/MWh	Total $/MWh
1996 estimate (5%)	19.16	6.07	7.59	32.82
1996 estimate (10%)	37.30	6.15	7.59	51.04

Source: Projected Costs of Generating Electricity, OECD 1998 p51-52
Note: Capital costs include interest during construction, licensing and decommissioning. The figures are in 1996 US$'s.

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42 Steve Thomas, *The economics of nuclear power: analysis of recent studies*, July 2005, PSIRU, Page 4.

43 World Nuclear Association, *Nuclear Power in India*, March 2005 (http://www.world-nuclear.org/info/inf53.htm).

44 World Nuclear Association, *Nuclear Power in India*, March 2005 (http://www.world-nuclear.org/info/inf53.htm).

45 In France a 1450 MW PWR reactor was estimated to cost 2% and 4% more than the Indian forecast (under a discount rate of 5% and 10% respectively). In Finland a 1000MW BWR reactor was estimated to cost 12% and 9% less than the Indian forecast (under a discount rate of 5% and 10% respectively).

6.2.2. France

The most recent nuclear plant constructed in France was a PWR reactor (Civaux 2) which started construction in 1991, came on line in 1999, and began commercial operation in 2002. EdF are now reported to be planning to build the first demonstration unit of an expected series of 1600 MW Framatome ANP EPRs. Construction of France's first unit is expected to start in 2007 at Flamanville on the Normandy coast, following public consultation and licensing. Construction is then expected to take 57 months to start up in 2012. EdF is aiming to firm up an industrial partnership with other European utilities or power users for its construction.

<u>Forecast Costs</u>

The French General Directorate for Energy and Raw Materials (previously the Directorate of Gas Electricity and Coal (DIGEC)) assessed the forecast costs of nuclear power in two studies published by the IEA in 1998 and 2005. These forecasts are set out in Table 6.5 below.

Table 6.5
Projected French Generation Costs under Varying Discount Rates

	Investment $/MWh	O&M $/MWh	Fuel $/MWh	Total $/MWh
2003 estimate (5%)	13.91	6.45	5.00	25.36
2003 estimate (10%)	27.50	6.40	5.30	39.30
1996 estimate (5%)	17.39	6.77	8.07	32.24
1996 estimate (10%)	34.61	6.86	7.69	49.15

Source: Projected Costs of Generating Electricity, OECD 2005 p51-52 and Projected Costs of Generating Electricity, OECD 1998 p67-69.
Note; Capital costs include interest during construction, licensing and decommissioning. The figures are in 1996 and 2003 US$'s.

The 1998 study conducted by the Directorate of Gas Electricity and Coal (DIGEC) shows the costs of a PWR 1450MW second sub series, similar to existing plants at Civaux (1) and Chooz (B). The costs are those assumed for a plant located at an average site with four reactors but with a programme of ten reactors. The load factor assumed is 84% and the lifetime is 30 years.

The 2005 study estimates the costs of an EPR reactor of the same type under construction in Finland (see section 6.3). Table 6.6 sets out in more detail the forecast costs of an EPR reactor based on the 8% discount rate assumed by DGEMP in their study.

Whether or how these French forecast data relate to actual experience of nuclear construction in France is not clear. It does not seem possible to obtain data on the station by station cost history of France's large and comparatively recent nuclear construction programme.

Table 6.6
Breakdown of the investment costs in France for a series of EPR (10 units); 2003 estimate

		Estimated Costs EPR
Capital Cost	€/kW	1283
Interest during Construction	€/kW	380
Construction Lead Time	years	5
O & M Cost	€/kW	51
O & M Cost (variable)	€/MWh	0.61
Fuel Cost	€/MWh	4.4
R&D Cost	€/MWh	0.6
Load Factor / Availability	%	90.30
Technology Lifetime	years	60
Discount Rate	%	8

Source; EPR Background and its Role in Continental Europe, AREVA Corporate Strategy Department, Didier Beutier, Westminster Energy Forum Thursday 23rd June 2005, p16.
Note: Investment cost is the mean for ten units. The currency basis is not reported.

6.2.3. Japan

Japan currently has two nuclear plants under construction, a 1000MW BWR reactor and a 900MW PWR reactor. The available cost estimates for Japan are shown in Table 6.7. These estimates are based on the forecast cost of constructing four ABWR (Advanced BWR) type models with a gross capacity each of 1350MW and therefore do not relate to currently constructing reactors. They show that forecast costs in Japan are high relative to the other countries we consider.

Table 6.7
Projected Japanese Generation Costs under Varying Discount Rates

	Investment $/MWh	O&M $/MWh	Fuel $/MWh	Total $/MWh
2003 estimate (5%)	21.80	14.50	11.80	48.10
2003 estimate (10%)	42.40	14.50	11.80	68.60
1996 estimate (5%)	24.91	16.84	15.71	57.45
1996 estimate (10%)	47.76	17.05	14.76	79.57

Source: Projected Costs of Generating Electricity, OECD 2005, 51-52 and Projected Costs of Generating Electricity, OECD 2005, 67-69.
Note; Capital costs include interest during construction, licensing and decommissioning. The figures are in 1996 and 2003 US$'s.

6.2.4. Re-started Construction

In the following cases plants currently under construction represent the resumption of construction of part-completed reactors abandoned for a number of years.

6.2.4.1. Russia

The Russian nuclear investment program is reported to amount to around US$15 billion in 2002 currency, of which US$ 9.7 billion is budgeted by 2010. Some 35% of this budget was for upgrading and replacement capacity, 56% of it for new capacity.[46]

All of the construction underway currently in Russia represents the resumption of construction of part-completed reactors abandoned for a decade or more. The reactors at Balakovo, Kalinin and Volgodonsk are V-320[47] and the Kursk reactor is an RBMK (the same reactor type as Chernobyl). Completion of Kursk-5 is in doubt.

The cost of completing partially built plant was estimated by the Federal Atomic Energy Agency (Rosatom) at an average cost of US$ 680/kW for the 9GWs of plant that were incomplete. In comparison Rosatom estimated that the cost of building new nuclear plant was US$ 900/kW.[48] This is a low figure and it is not clear on what basis it has been calculated.

6.2.4.2. Ukraine

After the accident at the 4th reactor unit at Chernobyl, the Supreme Soviet of Ukraine adopted on 2 August 1990 a moratorium on building new nuclear power units in the Ukraine. The construction work at unit 6 at Zaporozhe was interrupted and the construction of 4 new WWER type reactors at Khmelnitski and Rovno was also halted. The moratorium was lifted in October 1993.[49] As a result of the lifting of the moratorium, the two plants at Khmelnitski are currently under construction again.

6.2.4.3. Iran

The construction of the Bushehr plant in Iran was restarted in 1995 following the signature of an agreement with Russia to complete construction of the plant.[50]

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46 World Nuclear Association, *Nuclear Power in Russia*, September 2005 (http://www.world-nuclear.org/info/inf45.htm).

47 The V-320 is a version of the Russian WWER pressurised water reactor.

48 World Nuclear Association, *Nuclear Power in Russia*, September 2005 (http://www.world-nuclear.org/info/inf45.htm). The source does not report whether or not interest during construction is included. The currency basis is also not reported.

49 IAEA, *Country Nuclear Power Profiles*, Ukraine, 2003.

50 World Nuclear Association, *Plans For New Reactors Worldwide*, April 2005 (http://www.world-nuclear.org/info/inf76.htm).

6.2.4.4. Romania

On 31 August 2000 the former Government of Romania issued an Ordinance committing to the completion of the Cernovoda reactor on which construction was started in 1983.[51][52]

6.2.4.5. Argentina

In 1979 Atucha-2 was ordered following a government decision to have four more units coming into operation 1987-97. It was a Siemens design, a larger version of unit 1, and construction started in 1981 by a joint venture of CNEA and Kraftwerk Union (KWU). However, work proceeded slowly due to lack of funds and was suspended in 1994 with the plant 81% complete.[53] Construction has now been restarted.

6.3. Finland

In January 2002 the Finnish government approved an application by Teollisuuden Voima Oy (TVO) (a Finnish utility) to build a new reactor based primarily on economic criteria.

The reactor selected for Olkiluoto 3 is the European Pressurised Water Reactor (EPR). The electric capacity of the plant unit is approximately 1,600 MW. A French-German Consortium formed by Framatome ANP and Siemens has total responsibility for the construction of the Olkiluoto 3 plant unit, with Framatome ANP in charge of the reactor plant and Siemens of the turbine plant. Table 6.8 shows details of the plant now under construction.

Table 6.8
Nuclear Plants Under Construction, 2005

Country	Plant Name	Type of Reactor	Vendor	Net Capacity	Construction Started	Estimated Commercial Operation
Finland	OLKILUOTO	PWR	Framatome	1600 MWe	12/08/2005	2009

Source: IAEA, Power Reactor Information System, Last updated on 2005/09/1 and Ministry of Trade and Industry, Nuclear Energy in Finland, July 2005.

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51 IAEA, *Country Nuclear Power Profiles*, Romania, 2003.

52 The Ordinance also sets out the financing sources of the project which include Nuclearelectrica's (SNN) own sources, external loans based on sovereign guarantee and public funds from the Government. It also offered a set of financial incentives for the project including profit tax exemption, exemption from any import taxes due in Romania, Romanian income taxes exemption for foreign contractual partners, the payment of the accounts payable of SNN in respect of the sovereign guarantee for the external loans, contracted for the completion of Unit 1.

53 World Nuclear Association, *Nuclear Power in Argentina*, November 2004 (http://world-nuclear.org/info/printable_information_papers/inf96print.htm).

Forecast Costs

A study published in 2000 estimated that a new 1,250 MW nuclear power plant located at an existing site would cost €2.2 billion, including the interest during construction and initial fuel loading. Assuming 8,000 hours annual full-load utilisation[54] this corresponds to an electricity generation cost of €22/MWh.[55] Table 6.9 sets out full details of cost estimates from the study:

Table 6.9
Performance and cost data for new baseload power plants in Finland

		2000 estimate
Electric power	MWe	1250
Net efficiency rate	%	35
Investment costs	€ million	2186
Investment cost per power output capacity	€/kWe	1749
Fuel prices	€/MWh	1.00
Fuel costs of electricity production	€/MWhe	2.86
Annual fixed operation and maintenance costs	% of investment	1.50
Variable operation and maintenance costs	€/MWhe	3.41
Economic lifetime	years	40
Interest rate	%	5
Annuity factor	%	5.828

Source: Tarjanne and Rissanen, Nuclear Power: Least-Cost Option for Baseload Electricity in Finland, The Uranium Institute 25th Annual Symposium, 30 August – 1 September, Page 8.
Note: The interest during construction is included in the investment cost. For the nuclear power plant, the initial fuel loading is included in the investment. The interest rate used is a real rate of 5% per annum and the fixed price level of February 2000 has been used.

Further research in August 2003 reported by the World Nuclear Association put the cost of nuclear power at €23.7/MWh, on the basis of 91% capacity factor, 5% interest rate, and 40 year plant life.[56] The same study put the cost of coal at €28.1/MWh and natural gas at €32.3/MWh on the same basis). Factoring in the impact of emissions trading (where the price of carbon is assumed to be €20/t CO2) the electricity prices for coal and gas increased to €44.3 and €39.2/MWh respectively.

Research published by the IEA forecasts the costs of nuclear power in Finland both in two studies published in1998 and 2005. The 2005 study forecasts the costs of a 1500MW PWR reactor whilst the 1998 study estimate was based on a 1,000MW BWR plant. Table 6.10 illustrates these costs in terms of $/MWh.

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54 The historical average nuclear capacity factor in Finland is 91%.

55 Tarjanne and Rissanen, *Nuclear Power: Least-Cost Option for Baseload Electricity in Finland*, The Uranium Institute 25th Annual Symposium, 30 August – 1 September, Page 7.

56 World Nuclear Association, *Nuclear Energy in Finland*, June 2004, (http://www.world-nuclear.org/info/inf76.htm). The source does not report whether or not interest during construction is included. The currency basis is also not reported.

Table 6.10
Projected Finnish Generation Costs under Varying Discount Rates

	Investment $/MWh	O&M $/MWh	Fuel $/MWh	Total $/MWh
2003 estimate (5%)	16.30	6.10	5.10	27.50
2003 estimate (10%)	31.20	6.10	4.90	42.20
1996 estimate (5%)	22.01	7.95	7.32	37.28
1996 estimate (10%)	40.56	8.05	7.32	55.93

Source: Projected Costs of Generating Electricity, OECD 2005, 51-52 and Projected Costs of Generating Electricity, OECD 1998, 67-69.
Note; Capital costs include interest during construction, licensing and decommissioning. The figures are in 1996 and 2003 US$'s.

The 2003 costs shown in Table 6.10 are based on an overnight construction cost of US$1,895/kW, total fuel costs of US$5.13/MWh (falling to US$4.9 with a 10% discount rate) and O&M costs of US$48/kW (in 2010).[57] Finland's projected O&M costs were low relative to the other countries in the sample[58] except France. Finland was also the only country in the sample to assume an increase in fuel cycle costs. All other counties assumed stable costs and historic data shows fuel cycle costs have been falling.[59]

Forecast Costs Olikiluoto

Existing Finnish cost forecasts do not include the EPR reactor type which is the design to be constructed at Olikiluoto.

A forecast of the cost of an EPR reactor in France prepared by DGEMP (French Energy Directorate) is illustrated in section 6.2.2, Table 6.6.[60] This forecast estimates that the capital cost will be €1,283/kW excluding interest during construction, lower than the 2003 estimate of overnight construction costs for a PWR reactor. However, this forecast is likely to be subject to errors as the reactor will be the first constructed of its kind. In addition this forecast is based on construction of the plant in France, costs for construction in Finland could vary.

Project Financing Olikiluoto

TVO is buying the European Pressurised Water Reactor (EPR) to be constructed at Olikiluoto from Areva's Framatome ANP subsidiary under a turnkey contract.[61, 62] TVO have

57 International Energy Agency and the Nuclear Energy Agency, *Projected Costs of Generating Electricity*, OECD 2005, p.43-44.

58 Canada, the US, Czech Republic, Germany, Netherlands, Slovak Republic, Switzerland, Japan. Korea and Romania.

59 International Energy Agency and the Nuclear Energy Agency, *Projected Costs of Generating Electricity*, OECD 2005, p. 44.

60 AREVA Corporate Strategy Department, Didier Beutier, *EPR Background and its Role in Continental Europe*, Westminster Energy Forum Thursday 23rd June 2005.

61 A turnkey contract is a fixed price contract. The consortium has total responsibility for the plant equipment and buildings, licensability and performance and time schedule.

62 Nucleonics Week, *Bids Give TVO A Range Of Choices For Fifth Finnish Reactor Project*, 3 April 2003.

said the total price of the contract is "around" €3-billion, including first fuel core, a plant-specific training simulator, and infrastructure.[63]

Shareholders in the unit are expected to fund between 20-25% of the project the remaining funding being a mixture of loans and credit.[64] For example, Fortum is expected to invest €185 million to obtain approximately 25% of the company.[65] In all more than 60 Finnish companies will participate in the acquisition of the plant.[66]

According to the European Renewable Energies Foundation (EREF) much of the remaining funding was arranged through a syndicated loan arranged by Bayerische Landesbank (which is owned by the state of Bavaria).[67]

EREF state that Bayerische Landesbank (BLB) gave a €1.95 billion syndicated loan at an interest rate of 2.6% to TVO for the purchase of the Framantone EPR at a fixed price of €3.2 billion. EREF state that the loan is a syndicated revolving credit of €1.95 billion with two tranches maturing in 2009 and 2011 respectively. They add that the other banks in the syndicate are Handelsbanken, Nordea, BNP Paribas and JP Morgan.[68]

EREF also state that Areva received an export credit guarantee of over €610 million from the French export credit agency (COFACE) for the sale of the plant.

EREF have lodged a formal complaint with reference to the loan and other aspects of the financing, with the European Commission under state aid, export credit, procurement, safety and other regulations.[69] In summary they allege that:

- The syndicated loan was granted at a preferential interest rate of 2.6%.
- France's Coface supplied a €610 million export credit guarantee covering Areva supplies.
- The Swedish Export Agency (SEK) provided generous financial support.
- Finnish municipal authorities have entered into long term purchase obligations at a specific price (in violation, they allege, of EU procurement rules).
- The Finnish EPR's future electricity price will amount to 'dumping'.[70]

The European Commission (EC) has registered the complaint meaning it will open an investigation. The procedure involves a preliminary investigation by the directorate, followed

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63 Nucleonics Week, *European 'green power' generators challenge EPR's competitiveness*, 16 December 2004.

64 Nucleonics Week, *Vendor credits to cover 80% of TVO reactor*, 23/10/2005 and *Shareholders leap at chance for stake in new Finnish unit*, 27/11/03.

65 Nucleonics Week, *Nuclear still seen as Finland's best bet for new baseload power*, 19 May 2004.

66 TVO press release, *Olkiluoto 3 investment decision made - European pressurised water reactor supply contract signed*, 19/12/2003.

67 EREF have issued an action before the European Commission calling for an investigation into aspects of the financing of the project, see EREF, Press Declaration, EU investigation requested into illegal aid to Finnish nuclear plant, 13/12/04.

68 EREF, Press Declaration, *EU investigation requested into illegal aid to Finnish nuclear plant*, 13/12/04.

69 The complaint was lodged on 14th December 2004.

70 World Nuclear Association**,** *The European Commission (EC) is to investigate the construction of Finland's, News Briefing* 03-11 and Nucleonics Week, *European 'green power' generators challenge EPR's competitiveness*, 27/11/03.

by a decision on whether there are grounds to believe state aid was involved. If the EC does find grounds formal procedures will be launched.[71]

Electricity Sale Agreements

TVO is a public-private partnership company, 43% government-owned (including 27% owned by Fortum) and 57% private.

In all more than 60 Finnish companies will participate in the acquisition of the new plant.[72] The owners of the new company will then take their shares of electricity at cost, any unwanted portion being sold by them into the Nordic market. The private owners are mostly heavy industry with a high demand for base-load power.[73] Bids to TVO for shares of the 1600 MW output totalled 2000 MW.[74]

However, according to EREF some of the participants, in particular a Finnish communal authority, will sign a long-term obligation to purchase electricity at a fixed price.[75]

6.4. China

Table 6.11 shows the nuclear plants that are currently under construction in China, and Table 6.12 illustrates possible nuclear power plant orders over the next 2-3 years.

Table 6.11
Nuclear Plants Under Construction, 2005

Country	Plant Name	Type of Reactor	Net Capacity	Construction Started	Estimated Commercial Operation
China	TIANWAN	WWER	1000 MWe	20/10/1999	N/A
China	TIANWAN	WWER	1000 MWe	20/10/2000	N/A

Source; IAEA, Power Reactor Information System and Steve Thomas, The economics of nuclear power: analysis of recent studies, July 2005, PSIRU, Page 6.

Table 6.12
Possible Nuclear Plants orders in the next 2-3 years

Country	Site	Bidders	Need	Possible order date	Forecast completion
China	Sanmen	BNFL/Westinghouse (AP1000), Russia	2x1000MW	2005/06	N/A
China	Yangjiang	BNFL/Westinghouse (AP1000), Russia	2x1000MW	2005/06	N/A

Source; Steve Thomas, The economics of nuclear power: analysis of recent studies, July 2005, PSIRU, Page 6.

The Tianwan projects are based in Lianyungang City, Jiangsu Province, 300 km north of Shanghai. The project includes two Russian advanced VVER-1000 91-Type PWR units with

71 Nucleonics Week, *EC will investigate 'green power' complaint of state aid to TVO EPR*, 13 January 2005.

72 TVO website, *Olkiluoto 3 investment decision made - European pressurized water reactor supply contract signed*.

73 World Nuclear Association, *Nuclear Energy in Finland*, September 2005 (http://www.world-nuclear.org/info/inf76.htm).

74 World Nuclear Association, *Nuclear Energy in Finland*, September 2005 (http://www.world-nuclear.org/info/inf76.htm).

75 EREF, Press Declaration, *EU investigation requested into illegal aid to Finnish nuclear plant*, 13/12/04.

1,060 MW of installed capacity each. Russia will supply the design of the project and the main equipment although some of equipment will be procured from third parties. The Chinese party is responsible for civil engineering, erection and project management. The first concrete was poured in October 1999. Unit 1 and unit 2 were scheduled to complete for commercial operation by the end of 2004 and 2005, respectively but are both still under construction.[76]

In addition to the two plants currently under construction, it has been reported that two plants (each with two 1000MW units) may be ordered in the next 2-3 years.

Forecast Costs

There is very little publicly available information on the cost of Chinese nuclear power projects. The most recent set of comprehensive forecasts we have found were published by the IEA in 1998. They are set out in Table 6.13.

Table 6.13
Projected Chinese Generation Costs under Varying Discount Rates

	Investment $/MWh	O&M $/MWh	Fuel $/MWh	Total $/MWh
Phase 2 Qinshan Project (5%)	12.12	5.69	7.56	25.37
Lingao Project (5%)	17.14	5.84	7.83	30.81
Phase 3 Qinshan Project (5%)	15.82	7.84	3.03	26.29
Phase 2 Qinshan Project (10%)	25.69	5.76	7.56	39.01
Lingao Project (10%)	36.92	5.91	7.83	50.67
Phase 3 Qinshan Project (10%)	32.96	8.38	3.03	44.37

Source: Projected Costs of Generating Electricity, OECD 2005, 51-52 and Projected Costs of Generating Electricity, OECD 1998, 67-69.
Note; Capital costs include interest during construction, licensing and decommissioning. The figures are in 1996 US$'s.

The Lingao project comprised two PWR reactors each with a capacity of 1,000MW. The plants began construction in 1997 and were completed in 2002. The Qinshan project comprised two 600MW PWR reactors in the second phase and two 700MW Candu reactors in the third phase. The Qinshan 2 reactors started construction in 1996/97 and completed in 2002/04.[77]

Of these three projects Qinshan phase 2 was predominantly 'home made'(using independently developed Chinese technology) and this is said to explain its lower investment cost per/kW.[78]

The estimates are based on feasibility studies and are expressed in 1996 prices. The construction costs for the Qinshan 2 project were later re-estimated due to the effect of high

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76 IAEA, *Power Reactor Information System*, 2005.

77 IAEA, *Power Reactor Information System*, 2004.

78 International Energy Agency and the Nuclear Energy Agency, *Projected Costs of Generating Electricity*, OECD 1998, 105-106.

inflation and interest rates on the projects costs. The re-adjusted base costs[79] were US$1,465 and US$1534kW respectively.[80]

General cost estimates have also been reported by some industry sources in China. These sources indicate that for some foreign joint venture projects, the cost may be about US$50/MWh or more.[81] At prevailing exchange rates, these estimates are higher than the IEA forecasts published in 1998. This may indicate either an increase in the cost of nuclear power since those forecasts[82] or an underestimation of costs in the feasibility studies to which the IEA data refers.

Concurrently the China National Nuclear Corporation (CNNC) Chief Executives have asserted that the company's CNP-1000 PWR could be built at a cost under US$1,300 per/kW for an installed plant.[83] This figure has been used as a benchmark for future bids from foreign vendors.[84] This figure is not inconsistent with the IEA estimates published in 1998 (which forecast that the Qinshan 2 reactors would cost US$1,465 and US$1534kW respectively). However, it is low relative to the industry sources quoted who have said that it is not a credible figure.[85]

By way of comparison the IEA estimated in a study published in 2005 that for most plants in the sample of countries that participated[86] overnight construction costs vary between US$1000 and US$2000/kW whilst levelised costs vary between US$21-US$31/MWh based on a 5% discount rate.[87]

Issues in Cost Comparison in China

One reason for which the CNNC estimate may not be perceived to be a credible figure is that Chinese cost estimates reportedly may fail to apply a discount rate or account for depreciation.

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79 Base costs include expenses at leading time including land cost and site preparation cost, equipment purchasing, transportation and insurance fee, construction and erection costs, costs of design, engineering and services, project management costs, start-up cost, two thirds (for PWR) or total (for PHWR) the cost of nuclear fuel of the first core and contingency allowance.

80 International Energy Agency and the Nuclear Energy Agency, *Projected Costs of Generating Electricity*, OECD 1998, 105-106.

81 Nucleonics Week, *State official suggests China may adopt two-track technology policy*, 30 June 2005. The source does not indicate the price base for the estimate or the specific items included.

82 However, the other countries we have considered (Japan, France and Finland), except for Romania, have all experienced a fall in the total costs of nuclear power between 1998 and 2005.

83 CNNC has developed the indigenous CNP-1000 PWR based on existing Framatome plants at Daya Bay and Ling Ao. The source does not indicate the price base for the estimate or the specific items included.

84 Nucleonics Week, *Chinese investment accounting pressures foreign PWR bidders*, 11 August 2005.

85 Nucleonics Week, *Chinese investment accounting pressures foreign PWR bidders*, 11 August 2005.

86 The counties in the sample are Canada, the USA, the Czech Republic, Finland, France, Germany, the Netherlands, Slovakia, Switzerland, Japan, Korea, and Romania.

87 International Energy Agency and the Nuclear Energy Agency, *Projected Costs of Generating Electricity*, OECD 2005, 51-52 and International Energy Agency and the Nuclear Energy Agency, *Projected Costs of Generating Electricity*, OECD 2005, P.43-45. Note; this study is based on 2003 prices.

According to a report by Nucleonics Week[88] the Chinese system does not even refer to the average generating cost over a projects lifetime. Instead generation costs are calculated annually. The sales price is then calculated simply by dividing required revenue for any period by estimated generation. The rate of return to investors is calculated at between 10 and 15% of the selling price of power (the source does not specify if this figure is real or nominal).

The report also points out that the Chinese generation cost equation does not include taxes and dividend payments despite the fact that the electricity price is calculated using these factors. This further complicates comparison of Chinese generation cost figures.

Financing

According to the CNNC, China plans to spend nearly $50 billion on nuclear energy by 2020. That would add roughly 30 new power plants to the 11 reactors China already operates or is building.[89]

Reportedly only CNNC and Guangdong Nuclear Power Group are permitted to develop nuclear projects. The five national independent power groups are theoretically only allowed to be minority investors.[90]

Two indigenous nuclear projects illustrate this ownership structure:

1. The Ling Dong project (two 1,000MW PWR reactors of Chinese design at Ling Dong) was expected to be owned through a holding company of which CNNC would own 45%, Guangdong province would own 45% share and the remaining 10% would be controlled by investors from China's electrical engineering sector.[91]
2. Similarly for the next phase of the indigenous Qinshan PWR program, CNNC was expected to take a 51% share in a holding company responsible for that project. A provincial government body would control some of the shares in the remaining 49% of the project.[92]

There is no publicly available information about the financing of these indigenous plants. However, plants which are built to foreign designs have been subject to an open bidding process for both construction and financing.

The Sanmen and Yangjiang plants were subject to an open bidding process by the CNNC and China Guangdong Nuclear Power Co respectively. The bids were for third-generation designs, with contracts being awarded in 2005. Westinghouse bid its AP 1000 (which now has US NRC final design approval), Areva (Framatome ANP) bid it's EPR of 1600 MW and Atomstroyexport bid its V-392 version of VVER-1000.[93]

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88 Nucleonics Week, *Chinese investment accounting pressures foreign PWR bidders*, 11 August 2005.

89 USA Today, *Nuclear industry hopes to capitalize on surge in China*, 18 August 2005.

90 South China Morning Post, *Datang accelerates renewable power drive,* 31 August 2005.

91 Nucleonics Week, *Four more indigenous PWRs set for Guangdong, Qinshan*, CNNC says, 22 April 2004.

92 Nucleonics Week, *Four more indigenous PWRs set for Guangdong, Qinshan*, CNNC says, 22 April 2004.

93 World Nuclear Org, *Nuclear Power in China*, September 2005.

In its request for bids the CNNC also requested financing terms. The US Export-Import bank approved $5 billion in loan guarantees for the Westinghouse bid, and the French Coface company was expected similarly to finance Areva for Framatome ANP's bid.[94]

Westinghouse's bid is reported to price its state-of-the-art AP1,000 PWRs at $2.2 billion to $2.7 billion a pair.[95]

94 World Nuclear Org, *Nuclear Power in China*, September 2005.

95 Asia Times, *US's $5 billion nuclear gamble with China*, Kaushik Kapisthalam.

7. Financing Mechanisms and Potential Market Impacts

7.1. Past Financing Mechanisms for Nuclear Power

In the 1988 White Paper on Privatising Electricity[96] the proposal for a statutory obligation on Regional Electricity Suppliers (RECs) to contract for a specified minimum of non-fossil-fuelled generating capacity was first introduced. Subsequently implemented as the Non-Fossil Fuel Obligation (the NFFO), the obligation provided a guaranteed additional income to certain types of capacity, primarily nuclear, to facilitate their privatisation[97].

At that time it was envisaged that the RECs would contract for the majority of the NFFO capacity from nuclear power. However there were no restrictions on the source of the capacity and some capacity was also expected to come from renewables such as wind and tidal power. When established the NFFO was set to operate until 1998, with a review in 1994 of the requirement to extend the obligation until 1998.

In order to ensure the RECs were not disadvantaged by the NFFO the additional cost of non-fossil fuel generation was to be recovered through a levy (termed the fossil fuel levy) made on almost all electricity sales in England and Wales.

The NFFO obligation was discharged through what was called the Primary Nuclear Contract between Nuclear Electric and the Non-Fossil Fuel Purchasing Agency (an organisation set up by the RECs to administer the NFFO). The contract set up in April 1990 granted the NFPA exclusive rights to all the nuclear plant capacity of Nuclear Electric. In return Nuclear Electric received the Pool price for all electricity sold plus a premium (based on the levy) to be paid directly by the NFPA based on a maximum specified in the contract.

In 1994 Nuclear Electric forecast that the aggregate value of premium income that it would receive over the life of the contract was equivalent to £9.4billion in March 1994 values[98]. The £9.4billion is the sum of 1990-1998 expectations. NFFO was finally eliminated in 1998 but was reduced after 1996 because the privatised British Energy did not receive any money via the Obligation.

Since the first NFFO, four additional obligations have been imposed (NFFO-2, 3, 4 & 5) in 1991, 1994, 1997 and 1998. These subsequent NFFOs were designed not to provide additional revenue to nuclear capacity, but to secure capacity from new renewables projects, and the support to nuclear generation through the NFFO was finally eliminated at the end of 1998.[99]

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96 Privatising Electricity, *The Government's proposals for the privatisation of the electricity supply industry in England and Wales*, HMSO London, February 1998.

97 The NFFO applied in England and Wales, but parallel arrangements operated in Scotland and Northern Ireland.

98 Nuclear Electric, *The Government's Review of Nuclear Energy; Submission from Nuclear Electric plc; The Nuclear Non-Fossil Fuel Obligation and the Levy*, September 1994, Page3.

99 Department of Trade and Industry, *Promoting Renewable Energy: Experience with the NFFO*, 16 September 1999, Page 3.

7.2. Financing Options

It seems reasonable to conclude that no UK government in the foreseeable future would sanction a nuclear power station as a public sector project. This would be seen as providing inadequate incentives for efficiency, and as an inappropriate role for government in a liberalised energy market. However it is not possible to forecast with any confidence how financing by the private sector would be structured.

The two broad private-sector approaches to financing such a project are likely to be:

- *corporate finance*, on the balance sheet of the promoter (in this case probably an electricity generating company), or possibly a partnership; or
- non-recourse *project finance*, where the project is established as a separate legal entity.

Corporate finance is much simpler, although it generally requires a substantial equity input from the promoter, with typically less than half the capital raised by bank or bond financed debt. Project finance is in contrast very complex, but it normally protects the promoters from the threat of bankruptcy if the project fails, and it allows a higher level of debt, perhaps 75 per cent or even more, as the lenders can define their risks more precisely.[100] The promoters in this case would most likely include an electricity generator, construction companies, other major suppliers and perhaps financiers.

It is not clear which of these alternatives (or some hybrid) would be chosen for financing a UK nuclear plant.

It is conceivable that a nuclear power plant would be seen as too risky for financiers to support project financing, whereas a major generator might proceed with corporate finance. Or, conversely, project finance may be the only feasible alternative; or both might be feasible, leaving the potential corporate financier with a strategic decision, having regard to risk, financing costs and degree of control. The outcome would depend critically on aspects of government policy and on corporate and financier confidence in future policy. However, especially given the development in the UK of a strong tradition of *project financing* with some government involvement (as in multi billion pound PFI projects, for example in defence, and more commercial contexts, such as London Underground and the Channel Tunnel Rail Link), some such arrangement seems most likely for a new nuclear plant. It might or might not be described formally as a Public Private Partnership (PPP).

In either case, contracts would be designed to allocated risks as far as practicable to those in a position to control them. And in either case, after completion of construction and commissioning, there would normally be refinancing of the original debt, to enjoy the lower interest rates that would now be acceptable to lenders, the risks of default being then much less.

The public interest and hence the case for government involvement stems from two quite different sets of issues. One is that nuclear power has external impacts which would not fall on the private sector promoters. Some of these are positive (improving security of supply

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[100] An advantage of debt from the commercial perspective is that interest payments (in contrast to dividends) are treated as a cost to set against corporate tax. This commercial advantage is not of course a welfare advantage, since the saving to the project is a cost to taxpayers. However it would be unrealistic to make adjustments for this in comparing alternative generation costs, and we believe the effect would be small relative to the uncertainties in many other more important factors.

and reducing greenhouse gas emissions) and others negative (such as risks of radiation exposure from the plant or its subsequent waste). The government might consider that these impacts on balance merit some public support. The other set of issues is that the government itself, via its regulatory regimes, is a major player in determining the risks faced by electricity generators. In particular, the current electricity regulatory regime is geared to incentivise short to medium term efficiency (and renewables), not long term stability or security. Other major regulatory impacts are the land use planning system, and the nuclear licensing regime (although no government would intervene in the latter, beyond establishing competent regulatory authorities with adequate powers). Thus the government might consider that there are ways in which these regimes might be modified that would better serve the public interest and would also improve the commercial feasibility of new nuclear build.

Government measures to reflect external benefits of new nuclear generation might take one or more of several possible measures. These might be direct financial incentives, such as tax allowances[101], or direct grants, probably financed at least in part by electricity consumers.[102] Such support might apply to construction, or to operation, or to the initial costs associated with the planning inquiry or, much more substantially, the licensing. Or they might include less direct financial support such as government guarantees of some bank or bond financing.[103]

The most important of possible government measures to adapt the regulatory regimes would be to reduce the market uncertainty, by, for example, underwriting or requiring some minimum level of procurement of electricity from the new station over a long period. A recent but still embryonic variant of this general idea for support is that of carbon contracts[104], in which Government (specifically the Treasury) would auction off future carbon savings to the lowest bidder, thus potentially helping create a longer-term carbon market than the EU ETS can offer.

Such support might be financed in part by a contractual agreement with the government to share some of the gains which would arise on refinancing, if and when the project is successfully built and commissioned.[105]

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101 The US Energy Policy Act of 2005 includes a tax credit of 1.8 cents per kWh for the first eight years of production from new nuclear power plants (Neff, Shirley (2005) *Review of the Energy Policy Act of 2005*, Center for Energy, Marine Transportation and Public Policy, Columbia University 2005).

102 The Non-Fossil Fuel Obligation (NFFO), approved by the European Commission for 8 years in 1990, imposed an obligation on the then Regional Electricity Companies to buy a certain amount of electricity from non-fossil sources, any excess cost being met by a so-called Fossil Fuel Levy on all electricity sales. The scheme was established to overcome the problem that the market was unwilling to buy the existing nuclear power stations, with their prospective high decommissioning costs. However the NFFO was subsequently used also to support the development of renewable sources. After it ended in 1998 the levy continued, to support previous renewable contracts let under the NFFO, but these arrangements have now been superseded by the Renewables Obligation, under which electricity suppliers are required to source specified percentages of their electricity from renewable sources. There is no current provision to support nuclear generation.

103 This would reduce the commercial cost of capital, but would of course be transferring some of the risk of default to taxpayers and this would be a social cost. It could however produce a net national benefit as, besides protecting the private financers for the debt from the potential cost of default, it would also reduce uncertainty about the likelihood of this happening and reduce uncertainty about political support for the project.

104 D. Helm and C. Hepburn *Carbon contracts and energy policy: an outline proposal* Oxford 6 October 2005

105 This device has been pressed for some years by the NAO in the context of PFI projects (e.g. Finlay, David *Exploring the financing options*, The PFI Journal, Issue 50. 2005, pp 10-12), following some failures, in earlier years, of public sector bodies to recognise that such gains would arise.

A potential source of confusion and disagreement is the social valuation of major back-end expenditure by the private promoters, on decommissioning and perhaps waste disposal. We address the conceptual issues that arise in Appendix 1. In commercial appraisals it is commonly, and reasonably assumed that a fund is built up over the lifetime of a privately financed nuclear plant, which is subsequently drawn down to pay for the back-end expenses for which the supplier is liable. The commercial financial calculation will build this into the cost of the output. However the low risk market rate (essentially the government borrowing rate) at which the fund is assumed to accumulate will typically be lower than most estimates of social time preference. From a public interest perspective it would be strictly correct to discount the back-end spending financed in this way at the social time preference rate, which would reduce the estimated social cost.[106] In practice this would seem an unreasonable complication as general rule, but there may be a public interest case for checking, from time to time, whether the more rigorous analysis would have a material effect.

7.2.1. Financing and the cost of capital for privately-financed nuclear spending

As we have shown earlier in this report, the cost of electricity from any future nuclear station will depend very substantially on the cost of capital, which defines, for practical purposes[107], the discount rate for redistributing the expenditures over time (for example to calculate a cost/kWh). However, as we note in Appendix 1, this cost of capital cannot be forecast with any precision. It depends upon many technical and behavioural factors which would only emerge as the proposal is developed.

Estimates can, however, be made of the return on capital, or 'internal rate of return', that would be obtained, given various assumptions about capital, operating and maintenance and decommissioning costs, and about the price at which the station output might be sold. Such estimates can be compared with estimates of what expected return on capital might be needed to attract private financing. This is the approach adopted by OXERA (2005) in their note on costs of nuclear new build. Estimates of what return would be needed to attract finance can in turn be used to estimate the cost of nuclear power and the action that may be needed by government to make financing feasible.

Notwithstanding all these uncertainties, some estimate of the private sector cost of capital is needed to estimate the cost of electricity from a new nuclear plant. It can be said with confidence that this cost of capital would not be less than the rates of return[108] allowed on the regulatory asset base of the regulated electricity industry. The rates currently set by Ofgem are 6.5 per cent in real terms for a public electricity supplier and for the distribution network operators and 6.25 per cent in real terms for the national grid company. What premium above this would be needed by the market to finance a nuclear plant, for a

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[106] The difference between the social time preference rate and the government borrowing rate means that there is some extra cost of public borrowing at the margin, not reflected in the market rate, or a corresponding social benefit from saving such as that for a decommissioning fund.

[107] The privately financed cost of capital is the sum of the risk free rate (i.e. the cost of government debt), plus a risk premium. The risk premium is a social cost, but the risk free rate is a little lower than values typically derived for social time preference. This introduces a difference between strict social welfare costs and financial costs, and could be of practical concern if a comparison were being made between publicly and privately financed sources of supply. However, where the alternatives being compared are essentially privately financed, social time preference is not a material issue. In the nuclear case it is potentially relevant in practice only to some costs or benefits falling outside the commercial financial calculation, as we discuss below.

[108] These rates of return are defined in terms of the weighted average cost of capital (WACC), taking account of debt and equity financing.

plausible degree of government support as discussed above, is a matter for bold judgment. In the long term, if a nuclear programme became established, it might be no more than a percentage point. But initially a substantially higher premium, perhaps in the region of 2 to 3 percentage points, seems more plausible (i.e. a premium of some 7 percentage points above the risk free rate). This implies that, in deriving a cost per kWh from a set of capital costs and operating costs, a discount rate of around 9 per cent in real terms might be appropriate. (This is simply to reflect the financing costs, and assumes that any appropriate adjustments for potential time or cost overruns have already been made.)

7.2.2. Discounting and Costing of Publicly-Financed Spending and of Externalities

Any government support for nuclear power is unlikely to include substantial public grants or loans to the nuclear supplier. However the financial cost of public loans would be recovered from the price of the output in the same way as other debt, and it would seem most sensible to treat them as simply another source of debt finance. Grants would not of course be reflected in the output price, but would be need to be handled in any analysis of the social cost of nuclear power as one of many social costs and benefits that do not appear as such in the commercial financial estimates.

7.3. Electricity Market Issues

On the assumption that any new nuclear power plant would have to operate within the context of the prevailing electricity wholesale market arrangements, it is important to consider the potential implications of such market arrangements for investment in new nuclear plant.

The current wholesale electricity market arrangements, known as the British Electricity Trading and Transmission Arrangements (BETTA), have two central features:

- electricity is traded bi-laterally between buyers and sellers, under contract terms agreed between the parties; generators can sell their output under contract to retailers or large consumers, over the counter, or through power exchanges; and
- a balancing market that allows the system operator to buy or sell energy close to real time, to maintain system balance.

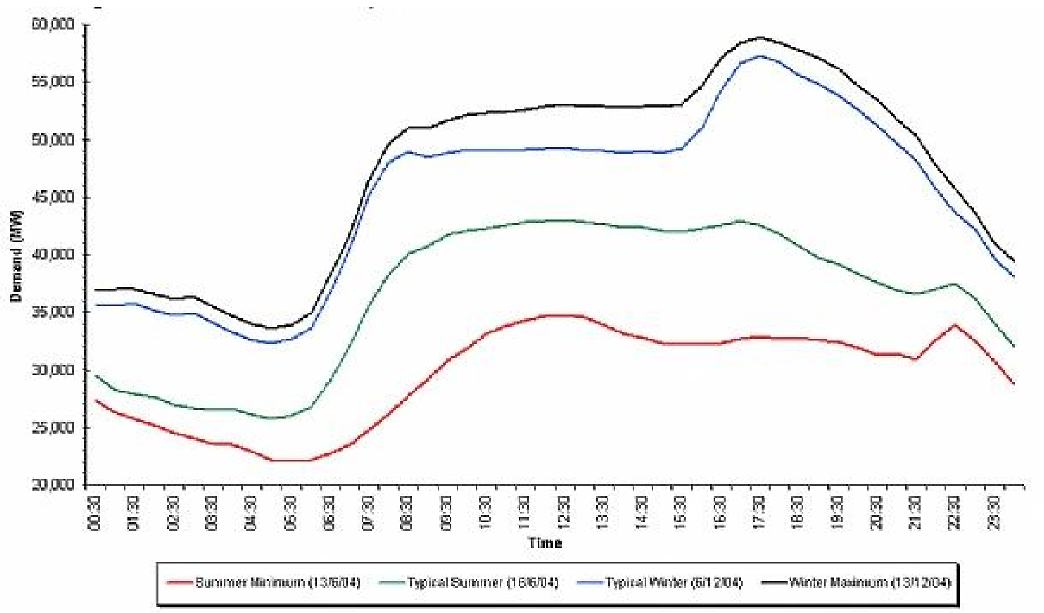
Experience shows that generators typically sell the majority of their output through the bi-lateral contract market, in order to avoid the less predictable prices in the balancing market.

System demand varies continuously throughout the day and over the course of the year. Both within day and over the year the overall scope of variation can be very large. Figure 7.1 shows daily load curves for the summer minimum and winter maximum days, and also the typical summer and winter days. This data indicates that within the year 2004/5, summer minimum demand fell towards 20 GW, while the winter maximum demand rose to almost 60 GW.

At the present time, the total capacity of the nuclear plants in England and Wales is around 9.5 GW, which is less than half the current minimum system demand. Moreover, the current expectations on plant retirements are that the available nuclear capacity will begin declining from 2006-7, and that:

- the whole of the 2.4 GW of Magnox capacity will be taken out of service by 2010/11[109]; and
- All of the current 5.9 GW of AGR capacity will be taken out of service by 2023.[110]

Figure 7.1
GB Summer and Winter Daily Demand Profiles in 2004/05



Source: NationalGrid 2005 Seven Year Statement

The variation in load over time can also be shown more systematically in the form of a load duration curve, which plots the percentage of time that total demand is at different levels. This is shown in Figure 7.2 for 2004.

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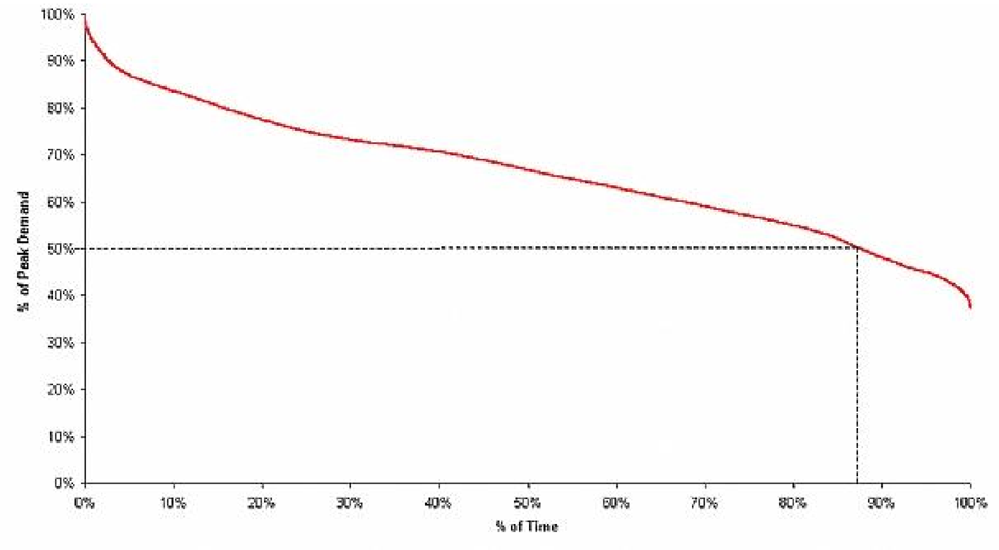
[109] NationalGrid Seven Year Statement 2005.

[110] Hansard, House of Lords, 24 February 2005, column WA232

Figure 7.2
Annual Load Duration Curve for 2004



Source: NationalGrid 2005 Seven Year Statement

Because of the substantial variability in demand, wholesale market prices also vary substantially, according to the time of the day and season of the year. For example, in 2005, balancing market prices on a typical winter day varied from just over £17 per MWh (1.7p per kWh), to over £44 per MWh (4.4p per kWh). On a typical summer's day, the lowest daily prices were a little over £17 per MWh, and rose up to over £42 per MWh.

Market participants can seek to avoid these large price variations by means of bilateral contracts of varying length, and energy purchasers will generally seek to enter contracts that can provide generation to match their anticipated demand variations. Contract prices themselves can vary widely, depending on contract characteristics. For example, Table 7.1 shows recent UK Power Exchange prices for base load, peak load, and off-peak contracts. Apart from illustrating the strong recovery in power prices that has occurred over the last several years, this shows the significant commercial advantage that can be derived from the ability to offer power other than at base load.

Table 7.1
Electricity Contract Prices by Contract Type (£/MWh)

Year	Quarter	Base Load	Peak	Off-peak
2003	1	17.41	21.50	15.15
2003	2	15.21	18.03	13.64
2003	3	18.70	27.30	13.88
2003	4	22.06	27.10	19.25
2004	1	20.62	24.63	18.40
2004	2	19.57	23.57	17.36
2004	3	21.01	24.59	19.02
2004	4	24.50	30.11	21.35
2005	1	30.12	37.35	26.14
2005	2	31.56	37.56	28.12

Source: UK Power Exchange and NERA calculations

The large range of variation in both electricity demand and price over time means that a generator able to provide a flexible level of output is likely to fare better in this wholesale market than a generator whose output is largely fixed[111]. Flexible and predictable plants provide a natural hedge against the short-term market risks. A generator with relatively inflexible output, like the existing nuclear plants, may be constrained to offer contract sales only to the lower-value base load market, or may need to expose itself to the balancing market in order to offer more flexible contracts.

The overall effect of these wholesale market features is that nuclear generation plant are less well suited to meeting present wholesale market requirements than, say, modern more flexible CCGT plant, and the average price per MWh at which a nuclear plant can sell its output is likely to be less[112]. Some mitigation to these market issues for nuclear generation may be possible in the future, if new technology allows more flexible operation of future plants.

Critics of the current wholesale market arrangements (and their predecessor NETA) have argued that the specific pricing rules that operate can impose on inflexible plants commercial penalties that exceed the opportunity cost imposed by the plant's operational limitations. In that case, modification of these rules so that imbalance charges more closely reflect opportunity costs would potentially be beneficial to nuclear plant, and could improve the

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111 It is also beneficial to be able to offer a predictable level of output, which can be an issue for some forms of renewable generation

112 Somewhat similar issues exist for certain types of renewable generation, though in that case there may be additional issues arising from their inherently unpredictable output levels, depending on the technology type.

efficiency of the market. Beyond changes of that sort, further measures would clearly be possible that could be beneficial to nuclear power, but careful consideration would need to be given to their effect on market efficiency.

7.3.1. Mechanisms to Encourage Investments in Nuclear Plants

The previous section referred to the possibilities for modifying the market rules to improve the position of nuclear plants. In addition to changes to the market rules, there are clearly other ways in which general market conditions could be changed to enhance the position of nuclear plants. Particular examples of this kind of measures would be to:

- impose on all licensed suppliers[113] an obligation to buy a certain proportion of their energy from nuclear generators or low carbon sources more generally, thus creating an artificial demand for electricity from that source;

- modify the system dispatch rules in such a way that preference is given to the use of nuclear plants.

Though both of these measures would be possible, they may be viewed as undesirable for market efficiency reasons. First is the fact that all such measures are likely to create significant distortions in the electricity market, and so reduce the efficiency of the market and increase costs to consumers. Secondly, preferential treatment for nuclear generators may be challenged for two major reasons:

1. The electricity market in Britain, as in other EU countries, is required to operate in compliance with the EU Directives[114] on electricity markets, which contain various measures designed to ensure market liberalisation and competition at wholesale and retails levels. In particular the Directives require that generation plants be operated on the basis of merit order dispatch, and only allow preferential treatment for: (i) generation plants fired by indigenous fuel sources, and (ii) renewable generation plants. So, it would appear that any scheme that gave preferential treatment to nuclear plant would be in breach of the Directives.
2. In addition to this difficulty with the Directives, measures that place nuclear generation plant in an unduly favourable commercial position would risk being in breach of the Commission rules on state aids, as has been alleged by EREF to be the case in Finland at the moment.

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113 Licensed suppliers are those licensed to sell electricity to final consumers.

114 The key Directive is the Electricity Directive 2003/54/EC of the European Parliament and of the Council concerning common rules for the internal market in electricity was passed on 26 June 2003. It repealed Directive 96/92/EC.

7.3.2. Market Implications of a Large-Scale Nuclear Power Programme

As noted earlier, the existing nuclear powered generating plants in the UK tend to be relatively inflexible in that they cannot increase and decrease their outputs as quickly as other types of plants, particularly thermal plants. This means that current nuclear plants are less able to provide the capability to follow load that other plant types have, at least to some degree. With a relatively small proportion of nuclear plant in the national plant portfolio this need not bring difficulties, as their total generating capacity is generally below the troughs of demand, and so the rest of the load curve is filled by more flexible plants. However, if the proportion of nuclear plants increased markedly, the position could arise where there would be insufficient flexibility in the system to match demand effectively at all points in the load curve. This could be a particular problem at times of low demand, and measures might have to be taken to cope with this inflexibility. In practice, the scale of any such problems seems unlikely to be significant in the UK context within the foreseeable future, since, as noted above:

- the total capacity of nuclear plants in England and Wales is around 9.5 GW, that is less than half of the current minimum system demand summer minimum of over 20 GW;
- current expectations on nuclear plant retirements mean that the available nuclear capacity will begin declining from 2006-7, and that the whole of the 2.4 GW of Magnox capacity will be taken out of service by 2010/11, with all the 5.9 GW of AGR capacity being taken out of service by 2023.

Nevertheless, it would be desirable for an assessment of the impact of new nuclear investments on the market to be carried out, in the light of any investment programme that is developed.

7.3.3. Impacts of Investment in Nuclear Power on Other Sources of Electricity Supply

References are sometimes made to the “opportunity cost” of a nuclear investment programme, where what is meant is that there are knock-on effects of a nuclear programme on other types of non-thermal generation. This is not an issue of opportunity cost in the strict sense in which the term is used in economic analysis, but the general argument nevertheless needs to be considered. It is likely that any increase in investment activity in one generation technology will impact on other technologies. Plans for new nuclear generation can therefore be expected to depress the market’s appetite for new CCGT investment relative to what it otherwise would be, possibly on a MW for MW basis. With respect specifically to the effect on investment in renewables generation, there appear to be four main areas where concerns have been raised:

1. Diversion of Government finance away from renewable investment: it may be the case that the Government would only be willing to devote certain limited funds to efforts to incentivise power generation from non-fossil sources, whether this be nuclear or renewable. If that is so, then there would probably be a trade off between funding of nuclear power and funding of renewables. In that sense, it may be the case that increased investment in nuclear generation will “crowd out” renewable investment. However the objectives of promoting renewable sources are their contribution to

reducing emissions and to diversity and security of supply.[115] The rationale for measures such as the renewables obligation is partly that these contributions are external benefits, not reflected in the price at which they could sell electricity in an unregulated market, and that these are new industries which also merit extra support on that account. None of these objectives or rationales should be materially affected by nuclear power. Plausible national emissions targets into the long term future will remain tight with or without nuclear power. And public sector support for nuclear power would most likely be in forms which did not in budgetary terms compete directly with that for renewable sources.

2. Reduction in the market's appetite for investment in renewables: we described earlier in this report ways in which the market may find the private financing of nuclear power plants more difficult than conventional power plant. Similarly, private investment in renewable generation presents difficulties for private investors that are not present with fossil fuel plant. If it is assumed that the relevant private investors have only a limited appetite for the financing of such fossil fuel plants, then it may be the case that "crowding out" of renewables may occur as a result of additional nuclear investments. Once again, this is a matter where, in the confines of this cost study, it is only possible for us to speculate about what might happen in practice. However given the international interest in financing electricity generation it is perhaps unlikely that the existence or otherwise of a UK nuclear programme would have any material impact on the availability of finance for other sources.

3. Issues of impact on microgeneration: not all microgeneration investment will be renewable, but there has been recent interest in the subject, including a DTI consultation. The main questions here are the extent to which there would need to be radical changes to the configuration of distribution networks to accommodate microgeneration and whether large nuclear investments would make such developments less likely. A report for Government by Mott McDonald[116] suggests that such changes would be limited, though this view is not shared by all distribution companies[117]. It is possible that a large nuclear programme might reduce Government's willingness to promote necessary network changes, though this is clearly a matter of uncertainty. Microgeneration seems unlikely to become a major contributor to UK energy or electricity supply for many years, even in the most favourable circumstances, and its capacity to deliver significant carbon savings in average households is not yet proven[118].

4. Issues of inflexibility arising from the cumulative effect of nuclear investment and renewables investment: we noted earlier that nuclear powered generating plants tend to be relatively less flexible than other types of plants, particularly thermal plants. To at least some degree, it is also true for most types of renewable plants currently seen in the UK that they lack the flexibility or predictability of thermal plants[119]. This means that both nuclear plant and renewable plants can limit the system's capability to follow load and, if

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115 As with a financial portfolio, there is benefit in diversity. The maintenance of a nuclear component does not materially reduce the diversity value of renewables, whose risks are quite different from those of nuclear. The diversity benefit of nuclear power would be similar in type (though not necessarily scale) to that offered by renewables. The particular advantage of both technologies from a system or portfolio perspective is that their costs, once plants are constructed, are largely fixed and their costs are largely uncorrelated with those of the dominant fossil fuel technologies. See S. Awerbuch in Sussex Energy Group, op. cit. Annex B.

116 Mott McDonald *System integration of additional micro-generation report to the DTI* 2004

117 Sussex Energy Group *Response to EAC inquiry 'Keeping the lights on'* 2005

118 Sussex Energy Group, op. cit.

119 This is less the case with landfill gas, wastes, or biomass, but applies to wind and some hydro plants, which account for a major portion of total renewable capacity currently.

the combined proportion of nuclear and renewable plants increases very substantially, the position could arise where there would be insufficient flexibility in the system to match demand effectively at all points in the load curve, so reducing the value of renewable (and nuclear) sources. Assessment of the significance of this issue again entails judgement. But given the fact any credible new nuclear investment programme is likely to be well within the scale of the current nuclear capacity that is expected to be phased out over the next 15 years or so, any such adverse impact seems unlikely.

Thus in terms of analysis of the public interest, there seems little reason to conclude that nuclear power will have a negative effect on government support for renewable sources. Whether it might nonetheless have an impact because of institutional or political pressures (or lack of time in the government's policy agenda) is, again, a matter for judgement rather than detailed analysis.

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Appendix A. Discounting and the Cost of Capital

Since the early 1960s it has been commonplace, in the public and private sectors, to use ‘discounted cash flow’ techniques to compare expenditures or revenues over time. This typically entails dividing £1 of cost or benefit in, say, year 10, by a factor $(1+d)^{10}$, to convert it to a ‘present value’ in year 0, where *d* is the ‘discount rate’. Or the discount rate may be used to convert a cost stream into a constant annual stream, like a mortgage repayment; or into an average unit cost of the associated output (such as p/kWh of electricity).

In private sector appraisal, this discount rate is generally equated with the financial cost of capital for the investment in question. In public sector welfare analysis in the UK it is generally equated with an estimate of ‘social time preference’ – that is a measure of how much society in general weights a future extra £1 of cost or benefit relative to a current £1. Appraisal of private sector investment is usually undertaken from the perspective of potential investors; or sometimes, by government or others, to assess the feasibility of a privately financed project. Welfare analysis, in contrast, is generally undertaken to assess the public interest.

In the 1960s and 1970s there was much debate in the UK about the comparative costs of nuclear and fossil fuelled electricity generation, in which the discount rate was seen as a major factor. In those days both energy sources were supplied by nationalised industries, financed by public debt. It is now fairly uncontentious in government that, in those circumstances, the appropriate rate would have been social time preference[120], and that there was no need to take any separate account of the cost of capital (i.e. the cost of the public debt used to finance these investments). However these circumstances no longer hold. Future electricity generation will be privately financed.

In this Appendix we address the relatively unusual issue of assessing the public interest for a privately promoted and mainly privately financed investment. This includes factors which would not be covered by a commercial financial appraisal, including the possibility of very long term costs of waste disposal, which raises discounting issues of its own, and was not considered in the 1960s and 1970s.

The handling of discounting and the cost of capital in comparing nuclear costs with other costs is thus more complicated than in earlier years. It is further complicated by involving the traditions of financial economics, which does not usually recognise the concept of social time preference as separate from the financial cost of capital, and of welfare economics, which recognises social time preference, but sometimes (as in current UK Treasury guidance) does not recognise the financial cost of capital as a separate concept. However this does not prevent wide areas of analysis on which most technical experts can agree.

Two common sources of confusion we note for the record, as issues that need to be made clear in any analysis. They are not especially prominent in the nuclear debate. Nor are they generally sources of theoretical disagreement between experts, although expert views do diverge on how they are best handled in particular circumstances.

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[120] Some financial economists would say that the rate should be the government borrowing rate plus a factor for the ‘systematic risk’, or correlation with equity market yields, of the future cash flows, and an upward adjustment for corporation tax.. The government view for many years, with which we agree, has been that market rates are not a reliable indicator of society’s time preference.

One is the handling of general inflation, where many economists prefer to carry out analysis in 'real terms', while financial experts generally prefer figures in nominal, or cash terms, including a projection of future general inflation. Real terms analysis is carried out at a constant price level, which requires interest rates to be expressed in real terms (which is broadly equal to the usual nominal terms, minus the expected rate of inflation). Care should be taken to ensure that it is clear whether figures, in particular interest rates, costs of capital, or rates of return, are in real or nominal terms.[121]

The other is taxation, where the usual convention, for analysis from a public interest perspective, is to express costs at pre-tax (i.e. tax-inclusive) market prices, but to beware of any features which might unduly distort comparisons. Thus, for example, if a well defined and material tax (or subsidy) were applied to one source of supply, or one kind of financing, but not another, this should be allowed to affect the comparison only if it reflects the value of some external cost or benefit that applies to the one source but not the other.

The long term costs of waste disposal may fall to the public sector. If the capital and operating and maintenance costs can be identified they can be discounted (as the social time preference rate, perhaps at a decreasing rate over time) as a further social cost, subject to the comments below on the very long term.[122]

Other important social externalities are the negative ones of risk of uncontrolled release of fission products from a reactor, the risk of exposure of future populations to significant radiation from waste, and the positive ones of national security of electricity supply and of greenhouse gas emissions. Judgement on all of these factors needs, of course, to be informed by quantitative analysis, but we do not believe that explicit valuation by technical experts of a present value (or contribution to cost per kWh) of the radiation risks or impacts on security of supply would contribute to good policymaking. These are issues where strategic judgements need to be made by the ultimate decision makers and wrapping up an uncertain part of these judgements in present values would detract from this. In this view we are echoing a view widely expressed at a workshop of leading US academic experts on long term discounting. One contributor, quoted with approval by the conference editors, suggested a common sense approach as follows to the issue of very long term costs or benefits:

> *In a political decision setting, rather than simply calculating a net present value of benefits minus costs … the present value of the risk reduction costs to be borne by the current generation could be presented to decision-makers and the public, along with estimates of the ultimate effects (monetary and otherwise) of risk reduction in time and space. Decision-makers and others then have to weigh whether the benefits justify the costs. Toman (1999, p 34)*

The case against deriving present values of very long term impacts is strengthened by the confusion, especially severe in such contexts, between changes in monetary values over time (for example of environmental quality) and discounting simply to reflect time preference for marginal income.

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[121] Care is also needed, of course, to ensure that any costs being compared are on the same price basis, for some specified date, such as "January 2005".

[122] HM Treasury (2003) specify a social time preference rate for the UK This is currently 3.5% in real terms for periods of up to 30 years, decreasing to lower values for longer periods.

In contrast, the reduction in greenhouse gas emissions achieved by the nuclear plant over its lifetime should in principle be amenable to explicit valuation. However the relevant monetary value – the opportunity cost, or opportunity value to the UK – is the saving it provides in other expenditures to meet the nation's commitments to its own emissions target, however they may be set. This may or may not be similar to figures derived for a "world " value for the social cost of carbon.

Appendix B. Glossary of Terms

ABWR	Advanced Boiling Water Reactor – A further development of the boiling water reactor
AGR	Advanced Gas-cooled Reactor – A design commonly used in the UK
BWR	Boiling Water Reactor – the second most common world design, originally developed by General Electric
CCGT	Combined Cycle Gas Turbine – the dominant contemporary power technology as a result of its relatively low initial capital outlay
EPR	European Pressurised-water Reactor – a further development of the pressurised water reactor, currently under construction in Finland and under development in France
FBR	Fast Breeder Reactor – uses plutonium as a fuel. No commercial reactors of this kind operate anywhere in the world
PBMR	Pebble-Bed Modular Reactor – a small-scale reactor design promoted widely by industry, some way from being licensed or built
PHWR	Pressurised Heavy Water Reactor - most of these are Canadian CANDU reactors, though the Argentinean reactor is of different design
PWR	Pressurised Water Reactor – the most commonly used design in the world. There are several designs but those designed by, or derived from Westinghouse are the most common
RBMK	The Russian design of the Chernobyl type. No RBMK's have been ordered since the Chernobyl accident, though Kursk (ordered before that date) is officially being completed
WWER (VVER)	A long-established Russian design of pressurised water reactor

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