

GREENPEACE

The economics of nuclear power

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Contents

Executive summary

Rising construction costs	1
Rising construction times	1
Falling construction demand	1
Untested technology	1
Unfavourable market place	2
Unreliable forecasts	2
Subsidies needed	3
Contemporary case study: Finland's Olkiluoto plant	3
The alternative	4
Biographies	5

Part 1: The technology: status and prospects

Past experience	6
Analysis of past construction: evidence of learning	6
Longer construction	8
Economic impacts	8
Western Europe - UK	9
Declining construction	9
The current order book	10
A nuclear revival or decline?	10
Hang-over plants	11
New orders	13
Generation III/III+ plants: experience and status	14
Pressurised Water Reactors (PWRs)	15
Boiling Water Reactors (BWRs)	16
Candus	17
High temperature gas reactors (HTGRs)	17
Generation IV plants	18
Technological gaps	18
Economics	19

Part 2: Nuclear Economics

Main determinants of nuclear power costs	20
Fixed costs	20
Variable costs	23
Impact of liberalisation of electricity industries	23
US experience	24
Electricity reforms elsewhere	24
Dealing with risks in competitive electricity markets	24
Construction time	25
Reliability	25
Power purchase agreements	26
Long-term liabilities	26
Recent studies on nuclear costs and why they differ	27
Rice University	27
Lappeenranta University of Technology	27
Performance and Innovation Unit	27
Scully Capital	28
MIT	28
The Royal Academy of Engineering	28
PB Power	28
University of Chicago	28
Canadian Energy Research Institute	29
International Energy Agency/Nuclear Energy Agency	29
OXERA	29
UK Energy Review 2006	29
Long-term forecasting	31
Fuel prices	31
Interest rates	31
Carbon pricing	

Part 3: A Nuclear Revival?

Finland: The Olkiluoto order	32
Finland's background in nuclear power	32
The commercial arrangements for the order	32
The buyer	33
Experience to date	33
Lessons	34
France: Flamanville	34
The UK	34
Scale of programme, government support and benefits	35
Assumptions	36
Reactor technology and vendor choice	38
Evaluation of the UK's proposed programme	39
USA	39
China	41
Planned units	41
Proposed units	41

Part 4: The alternatives

Resource and potential: overview	42
Economic overview	43
Future prospects	43
Costs	43
Wind energy	43
Photovoltaics	45
Solar Thermal Electric	46
Hydro	46
Biomass	46
Geothermal energy	46
Tidal barrages	47
Wave energy	47
Tidal stream energy	47
Electricity costs	47
Current plant costs and performance	47
Integration issues	48
Conclusions	49

Annex A - Exporting reactors

Mergers of reactor vendors	50
Nuclear power and international financial institutions	50
Export credit agencies	51

Annex B - Funding long-term liabilities

Introduction	53
Experience from the UK	53
A better way to manage decommissioning funds	55

Annex C - Energy [R]evolution:

A Sustainable World Energy Outlook	57
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Endnotes	58
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Executive summary

Over the last two decades there has been a steep decline in orders for new nuclear reactors globally. Poor economics has been one of the driving forces behind this move away from nuclear power.

The civilian nuclear power industry has been in operation for over fifty years. During such a long period, it would be usual for technological improvements and experience to result in learning and subsequently enhancements in economic efficiency. However, the nuclear industry has not followed this pattern.

Rising construction costs

Country after country has seen nuclear construction programmes go considerably over-budget. In the United States, an assessment of 75 of the country's reactors showed predicted costs to have been \$45 billion (€34bn) but the actual costs were \$145 billion (€110bn). In India, the country with the most recent and current construction experience, completion costs of the last 10 reactors have averaged at least 300% over budget.

Rising construction times

The average construction time for nuclear plants has increased from 66 months for completions in the mid 1970s, to 116 months (nearly 10 years) for completions between 1995 and 2000.

The longer construction times are symptomatic of a range of problems including managing the construction of increasingly complex reactor designs.

Falling construction demand

There are currently only 22 reactors under active construction in the world. The majority (17) are being constructed in Asia and 16 of the 22 are being built to Chinese, Indian or Russian designs. None of these designs is likely to be exported to OECD countries.

Construction started on five of the reactors over 20 years ago and consequently the likelihood of the reactors being built to their current timetable is open to question. There are a further 14 reactors on which construction has started but is currently suspended, 10 of which are in Central and Eastern Europe. This low level of nuclear construction provides little relevant experience on which to build confidence in cost forecasts.

Untested technology

The nuclear industry is promoting a new generation of

reactors (Generation III and III+) and hoping that a wave of orders will be placed for them in the next few years.

Generation III reactors

The only Generation III reactors currently in operation are the **Advanced Boiling Water Reactors (ABWR)** developed in Japan. By the end of 2006, four ABWRs were in service and two under construction in Taiwan. Total construction costs for the first two units were well above the forecast range. Further problems have now arisen as cracking has been found in the blades of the turbines of two plants. A temporary repair might allow the plants back into service in 2007, operating at 10-15% below their design rating until new turbines can be supplied.

Generation III+ reactors

No Generation III+ plant has yet been completed and only one is under construction. The most widely promoted of these latest designs are the new generation of **Pressurised Water Reactors (PWRs)** and in particular **Areva's European Pressurised Water Reactor (EPR)** and the **Westinghouse AP1000**.

The EPR is the only Generation III+ plant under construction, at the Olkiluoto site in Finland – see case study below.

The AP1000 was developed from the AP600 design (Generation III). The rationales for the AP600 were:

- 1) to increase reliance on passive safety and
- 2) that scale economies (from building larger units as opposed to building larger numbers) had been over-estimated.

The AP600 went through the US regulatory process and was given safety approval in 1999. By then, it was clear that the design would not be economic and the AP600 was never offered in tenders. Its size was increased to about 1150MW in the hope that scale economies would make the design economically competitive, with an output increase of 80% and an estimated increase of only 20% in costs. The AP1000 has so far been offered in only one call for tenders, the call for four Generation III+ units for China placed in 2004, and won this contract in December 2006.

Other designs being developed include the **Advanced CANDU Reactor (ACR-1000)** and **High Temperature Gas Reactors (HTGRs)**. The most developed of the latter is a South African version of the **Pebble Bed Modular Reactor (PBMR)**. The project was first publicised in 1998 when it was expected that the first commercial orders could be placed in 2003. However, greater than anticipated problems in completing the design, the withdrawal of funders and uncertainties about the commitment of other partners has meant that the project time-scale has

slipped dramatically and the first commercial orders cannot now be taken before 2014.

Generation IV reactors

Even more speculative are the 'paper' designs for **Generation IV plutonium-fuelled reactors**. While several designs are being produced, technical difficulties make it unlikely that they will be deployed for at least two decades, if at all, while the economics of fuel reprocessing also remain unproven.

Unfavourable market place

The economics of nuclear power have always been questionable. The fact that consumers or governments have traditionally borne the risk of investment in nuclear power plants meant that utilities were insulated from these risks and were able to borrow money at rates reflecting the reduced risk to investors and lenders.

However, following the introduction of competitive electricity markets in many countries, the risk that the plant would cost more than the forecast price was transferred to the power plant developers, which are constrained by the views of financial organisations such as banks, shareholders and credit rating agencies. Such organisations view investment in any type of power plant as risky, raising the cost of capital to levels at which nuclear is less likely to compete.

The logic of this transfer to competitive electricity markets was that plant developers possessed better information and had direct control over management and so had the means as well as the incentive to control costs. Builders of non-nuclear power plants were willing to take these risks, as were vendors of energy efficiency services. Consequently, when consumers no longer bore the economic risk of new plant construction, nuclear power, which combines uncompetitively high prices with poor reliability and serious risks of cost overruns, had no chance in countries that moved to competitive power procurement.

Unreliable forecasts

In recent years there have been numerous studies of the economics of nuclear power. The values of the key parameters used to generate the forecast cost of nuclear power vary significantly from one study to another. For example, the assumed cost of construction ranges from **€725-3600/kW**, while the assumed construction time varies from 60 to 120 months. The resultant price of electricity consequently also varies significantly, producing a range of between **€18-76/MWh**.

Generating costs and capital costs

The most recent of these studies, produced for the UK

Government, gave a generating cost for nuclear electricity of **€57/MWh**, using many assumptions that would appear reasonable, for example 72 month construction time and an 80-85% load factor. However, given the UK Government's statement that there will be no subsidies, the real cost of capital used in this forecast is unreasonably low at 10%. A more realistic assumption (15% or more) would result in an estimated electricity generating price of around **€80/MWh**.

Oil prices

The long construction and proposed operating times for the reactors require some judgement of the impact of key variables far into the future. An important parameter is the price of oil. There is still a close price correlation between oil, gas and coal, so the price of oil affects the price of electricity. Since 1999, the four-fold increase in the price of oil has led to a marked increase in some regions in the price of gas and coal, with a consequent improvement in the relative economics of nuclear power.

However, there have always been fluctuations in the world price of oil, as was seen in the oil shocks of 1975 and 1980 when the price of oil increased by a factor of up to eight. However, in the first half of 1986, the price of oil collapsed back to 1974 levels. The high oil prices of 2005/06 were driven in part by increased demand for oil due to the economic boom in Asia and many forecast that the price of oil will stabilise at around \$60 per barrel over the coming decades.

The price of oil can also significantly impact on inflation and therefore increase interest rates, as happened in the 1970s oil shocks. These resulted in both lower energy demand and a significant impact on the economics of nuclear power, due to its large construction costs.

Carbon prices

In the medium to long term, the price of carbon may have a significant impact on the economics of nuclear power. The introduction of a European Emissions Trading Scheme established an international price for carbon for the first time. However, the current scheme is tied to the Kyoto Protocol which will need to be renegotiated for the post-2012 period, therefore there is considerable uncertainty over the future price of carbon even in the short term, never mind sixty years from now.

Given the lack of experience of a carbon price in the energy market it is difficult to assess its impact on the economics of different generators. Fluctuations in the European market since its establishment in 2005 have seen a high of **€30/tonne** for carbon, but a collapse at the start of 2007 to **€2/tonne**. Not only does there need to be a long term guarantee for the price of carbon, but, according to some, also a price which is significantly above the current market price. A recent study by Massachusetts Institute of Technology (MIT) calculated

that 'With carbon taxes in the \$50/tC range, nuclear is not economical under the base case assumptions'. The study went on to assess that nuclear power would only break even under its base case assumptions when carbon prices are in excess of \$100/tC¹ (€71/tC).

A nuclear renaissance?

The much touted 'nuclear renaissance' assumes that new plants will be built cheaper than the alternatives, on time and to cost, that they will operate reliably and that the cost of dealing with long-term liabilities such as waste disposal and decommissioning will stabilise. However, wishing for an outcome is not sufficient to make it fact. Until nuclear power actually meets all these criteria on a sustained basis, the additional risks of nuclear investment will be large.

Subsidies needed

It is now 29 years since the last order for a new nuclear power plant in the US and 34 years since the last order for a plant that was actually completed. Utilities suffered heavy losses in the 1980s as economic regulators became increasingly unwilling to pass huge cost over-runs from nuclear projects on to consumers, forcing utilities to bear the extra costs. The introduction of power markets has meant that plant owners are now fully exposed not just to the risk of cost over-runs but also to plant unreliability. The nuclear provisions of the **US Energy Policy Act of 2005 (EPACT 2005)** are an effort to reverse these changes and protect investors from that large economic risk.

The most important nuclear provisions of EPACT 2005 offer three types of support:

- a limited number of new nuclear power plants can receive an \$18/MWh (€13.7) **production tax credit for up to \$125m (€93.75m) per 1000MW (or about 80% of what the plant could earn if it ran 100% of the time);**
- a provision for federal loan guarantees covering up to 80% of project costs.
- up to \$500m (€375m) **in risk insurance for the first two units and \$250m (€187.5m) for units 3-6. This insurance is to be paid if delays, not the fault of the licensee, slow the licensing of the plant.**

These subsidies are said to be worth between \$2-20/MWh. Without these subsidies, it is unlikely that any US company would be considering investing in a new nuclear plant.

Government financial or contractual guarantees would effectively take nuclear power out of the market so that it is paid for, as in the past, by electricity consumers and taxpayers. If nuclear power is to be subsidised in this way, there needs to be clear and compelling evidence that this is a cost-

effective and worthwhile way to use taxpayers' and electricity consumers' money.

Contemporary case study: Finland's Olkiluoto plant

The Olkiluoto construction project in Finland is rapidly becoming an example of all that can go wrong in economic terms with nuclear new build. It demonstrates the key problems of construction delays, cost overruns and hidden subsidies.

A construction licence for Olkiluoto was issued in February 2005 and construction started that summer. As it was the first reactor ever built in a liberalised electricity market, it was seen as a demonstration that nuclear power orders are feasible in liberalised electricity markets and as a demonstration of the improvements offered by the new designs. To reduce the risk to the buyer, Areva offered the plant under 'turnkey' terms, which means that the price paid by the utility (TVO) is fixed before construction starts, regardless of what actually happens to costs. The contract allows for fines levied on the contractors if the plant is late. The schedule allows 48 months from pouring of first concrete to first criticality.

Finance

The financing details have not been published, but the European Renewable Energies Federation (EREF) and Greenpeace France made complaints to the European Commission in December 2004 that they contravened European State aid regulations. According to EREF, the Bayerische Landesbank (owned by the German state of Bavaria) led the syndicate that provided a loan of €1.95bn, **about 60% of the total cost, at an interest rate of 2.6%.** Two export credit institutions are also involved: France's Coface, with a **€610m export credit guarantee covering Areva supplies,** and the Swedish Export Agency SEK for €110m.

In October 2006, the European Commission finally announced it would be investigating the role of Coface. Export credit agencies normally involved in financially and politically risky countries in the developing world, hardly a category that Finland would fit into, and credits are not usually provided for use within the same internal market.

Regardless of the result of the Commission's investigation, the arrangements for Olkiluoto are based on substantial state aid that will not be available to many plants. The interest rate on the loan is far below the levels that would be expected to apply for such an economically risky investment.

Construction problems

In August 2005, the first concrete was poured. Almost immediately, things began to go wrong. In September 2005

problems with the strength and porosity of the concrete delayed work. In February 2006, work was reported to be at least 6 months behind schedule, partly due to the concrete problems and partly to problems with qualifying pressure vessel welds and delays in detailed engineering design.

In July 2006, TVO admitted the project was delayed by about a year and the Finnish regulator, STUK, published a report which uncovered quality control problems. In September 2006, the impact of the problems on Areva started to emerge. In its results for the first six months of 2006, Areva attributed a **€300m fall in first-half 2006 operating income of its nuclear operations** to a provision to cover past and anticipated costs at Olkiluoto. The scale of penalties for late completion was also made public. The contractual penalty for Areva is 0.2% of the total contract value per week of delay (past May 1, 2009) for the first 26 weeks, and 0.1% per week beyond that. The contract limits the penalty to 10%, about **€300m**. **In December 2006**, after only 16 months of construction, Areva announced the reactor was already 18 months behind schedule, which seems to assure that the full penalty will be due. It now seems likely that the project will fall at least **€700m over budget**.

Implications

The scale and immediacy of the problems at Olkiluoto have taken even sceptics by surprise. It remains to be seen how far these problems can be recovered, what the delays will be and how far these problems will be reflected in higher costs (whether borne by Areva or TVO). However, a number of lessons do emerge:

- The contract value of **€2000/kW, which was never – due to the turnkey nature of the contract – a cost estimate, now appears likely to be a significant underestimate. Actual costs seem likely to be no lower than that forecast by EdF, €2200/kW. This may yet turn out to be an underestimate.**
- Turnkey contracts may well be required by competitive tenders in liberalized electricity markets. Or regulators may impose caps on recoverable nuclear construction costs, which would have the same effect. The willingness of vendors to bear the risk of cost over-runs in the light of the Olkiluoto experience is subject to serious question.
- The skills needed to successfully build a nuclear plant are considerable. Lack of recent experience of nuclear construction projects may mean this requirement is even more difficult to meet.
- There are serious challenges to both safety and economic regulatory bodies. The Finnish safety regulator had not assessed a new reactor order for more than 30 years and had no experience of dealing with a ‘first-of-a-kind’ design.

The alternative

In contrast to the historical problems and future uncertainties of the economics of nuclear power there are energy sources and

measures whose financial performance is more predictable.

There is a growing awareness of the need to move away from the predominant use of fossil fuels, for climate and security of supply reasons. Energy efficiency and renewable energy sources can supply this need.

Energy efficiency

Energy efficiency must be the cornerstone of future energy policies. The potential for energy efficiency is huge. According to the French Ministry of Economy, changes in the production, transmission and use of energy (including transport) could result in a halving of global energy consumption – from the business as usual scenario – resulting in the saving of 9,000 million tonnes of oil equivalent (Mtoe) per year by 2050. In 2005 global nuclear energy production was 627 Mtoe.

An energy efficiency action plan proposed by the European Commission in October 2006 called for a 20% increase in energy saving across the EU. If fully implemented, this would result in energy consumption in the EU being 1,500 Mtoe by 2020, instead of the 1,890 Mtoe in the ‘business-as-usual’ scenario and compared to 1,750 Mtoe in 2004. As a result, energy bills in the EU would fall by **€100 billion per year (over the business-as-usual scenario)**.

Some energy efficiency measures will come at little or no cost, but others will require significant investment. Already Germany has a highly efficient energy economy, but analysis suggests that the country’s energy consumption could be reduced by 27% by 2015 using 69 measures across the industrial, commercial and residential sectors at an average cost of **€69/MWh**. This is an enormous energy saving programme to be introduced within a decade. The price of saving is below the likely cost of nuclear electricity.

Renewable electricity sources

The contribution of renewables is growing at a rapid rate with the annual investment growing from about \$7bn (**€5.3bn**) in 1995 to \$38bn (**€29bn**) in 2005. **During 2005 the total installed capacity of non-large-hydro renewables increased by 22 GW, which compares to a 3.3 GW increase in nuclear, much of which relates to increased capacity from existing reactors rather than from the construction of new reactors.**

Hydroelectricity and wind energy are expected to deliver the biggest increases in electricity production by 2020 - roughly 2000 TWh/year in each case. Both technologies are expected to deliver electricity at around **€40-50/MWh, which is likely to be competitive with nuclear, gas and coal - although this will depend on the prevailing price of carbon.** The prospects for solar thermal electric, wave and tidal stream energy are less certain but their generation costs may also be competitive with the fossil fuel sources.

Biographies

Stephen Thomas, - lead author - Professor of Energy Policy, Public Services International Research Unit, Business School, University of Greenwich, United Kingdom

Stephen Thomas is a researcher at the Public Services International Research Unit (PSIRU) in the UK. He specialises in the energy sector, particularly in energy restructuring, privatisation and regulation; nuclear energy; and environmental issues. **Member of an international panel appointed by the South African Department of Minerals and Energy to carry out a study of the technical and economic viability of a new design of nuclear power plant, the Pebble Bed Modular Reactor (2001-02).** Member of an independent team appointed by Eletronuclear (Brazil) to carry out an assessment of the economics of completing the Angra dos Reis 3 nuclear power plant (2002). Before joining PSIRU he worked for 22 years at the Science Policy Research Unit at Sussex University, where he carried out many international energy projects.

Peter Bradford, former chair at Nuclear Regulatory Commission, United States

Peter Bradford is a former member of the United States Nuclear Regulatory Commission, and former chair at New York and Maine utility regulatory commissions. Mr Bradford has taught at the Yale School of Forestry and Environmental Studies and the Vermont Law School. With 38 years of expertise in the field of energy law and policy, he is the author of many articles and one book. He is a member of the Policy Advisory Council of the China Sustainable Energy Project. He served on a panel advising how best to replace the remaining Chernobyl nuclear plants in Ukraine and also on an expert panel on the opening of the Mochovce nuclear power plant in Slovakia. Mr. Bradford is Vice-Chair of the Union of Concerned Scientists.

Antony Froggatt, international energy and nuclear policy consultant, United Kingdom

Antony Froggatt advises members of the European Parliament on energy issues via written reports, drafting amendments and providing briefings. He has given evidence to the Austrian, German and European Parliaments. He also provides analysis on energy policy to non-government organisations and the energy industry. Since 1997 Mr Froggatt has produced over 30 publications on energy-related topics.

David Milborrow, renewable energy studies consultant, United Kingdom

David Milborrow is an independent consultant who has been associated with renewable energy for 27 years. He specialises in studies of generation costs and wind integration issues. He lectures on this and other topics at several universities, writes for Windpower Monthly and is Technical Adviser to the British Wind Energy Association and other bodies.

Each author has contributed within their area of expertise. Mr. Froggatt alone has had a role in the entire document

Part 1:

The technology: status and prospects

Past experience

The construction costs of nuclear plants completed during the 1980s and early 1990s in the United States and in most of Europe were very high — and much higher than predicted today by the few utilities now building nuclear plants and by the nuclear industry generally.²

...the evidence shows that, historically, cost estimates from the industry have been subject to massive underestimates—inaccuracy of an astonishing kind consistently over a 40, 50 year period.³

I do not have any reason to believe CEZ [the Czech utility constructing the Temelin nuclear power plant] I have been lied to 9 times. I do not know why I should believe them in the 10th case.⁴

Analysis of past construction: evidence of learning

The civil nuclear industry should be an established and mature technology given that it is fifty years since electricity was first generated in a nuclear power plant. Since then a total of 560 civilian nuclear reactors have been commissioned of which 435 are still operating (see Table 1.1)⁵. In total over 12,000 power reactor operating years have been accumulated.

The production costs for most technologies reduce over time, due to technological improvements, economies of scale and efficiency improvements due to learning. However, not all technologies have achieved the same rates of economic improvements over time. Analysis undertaken by McDonald and Schrattenholzer suggests that the rate of learning, which represents the percentage reduction of costs for each doubling of the cumulative volume of productions, is much lower for nuclear power than for other technologies. A summary of the findings of this work can be seen in Table 1.2 below⁶.

Table 1.1 Nuclear capacity in operation and under construction in 2006

	Operating plants: Capacity MW (units)	Plants under construction: Capacity MW (units)	% nuclear electricity generation	Technologies	Suppliers
Argentina	935 (2)	-	7	HWR	Siemens, AECL
Armenia	376 (1)	-	43	WWER	Russia
Belgium	5801 (7)	-	56	PWR	Framatome
Brazil	1901 (2)	-	3	PWR	Westinghouse, Siemens
Bulgaria	2722 (4)	-	44	WWER	Russia
Canada	12584 (18)	-	15	HWR	AECL
China	7572 (10)	3610 (4)	2	PWR, HWR, WWER	Framatome, AECL, China, Russia
Taiwan	4884 (6)	2600 (2)	n/a	PWR, BWR	GE, Framatome
Czech Rep	3373 (6)	-	31	WWER	Russia
Finland	2676 (4)	1600 (1)	33	WWER, BWR, PWR	Russia, Asea, Westinghouse
France	63363 (59)	-	79	PWR	Framatome
Germany	20339 (17)	-	32	PWR, BWR	Siemens
Hungary	1755 (4)	-	37	WWER	Russia
India	3483 (16)	3113 (7)	3	HWR, FBR, WWER	AECL, India, Russia
Iran	-	915 (1)	-	WWER	Russia
Japan	47593 (55)	866 (1)	29	BWR, PWR	Westinghouse, GE, Hitachi, Mitsubishi, Toshiba
S Korea	16810 (20)	-	45	PWR, HWR	Westinghouse, AECL, Korea
Lithuania	1185 (1)	-	70	RBMK	Russia
Mexico	1360 (2)	-	5	BWR	GE
Netherlands	450 (1)	-	4	PWR	Siemens
Pakistan	425 (2)	300 (1)	3	HWR, PWR	Canada, China
Romania	655 (1)	655 (1)	9	HWR	AECL
Russia	21743 (31)	2850 (3)	16	WWER, RBMK	Russia
Slovak Rep	2442 (6)	-	56	WWER	Russia
Slovenia	656 (1)	-	42	PWR	Westinghouse
S Africa	1800 (2)	-	6	PWR	Framatome
Spain	7450 (9)	-	20	PWR, BWR	Westinghouse, GE Siemens
Sweden	8909 (10)	-	45	PWR, BWR	Westinghouse, Asea
Switzerland	3220 (5)	-	33	PWR, BWR	Westinghouse, GE Siemens
Ukraine	13107 (15)	-	49	WWER	Russia
UK	11852 (23)	-	20	GCR, PWR	UK, Westinghouse
USA	98145 (103)	-	19	PWR, BWR	Westinghouse, B&W, CE, GE
WORLD	369566 (442)	19210 (22)	16		

Source: World Nuclear Association, 'World Nuclear Power Reactors 2005-07' (<http://www.world-nuclear.org/info/reactors.htm>)

Notes:

1. Plants under construction does not include plants on which construction has stalled.
2. Technologies are: PWR: Pressurised Water Reactor; BWR: Boiling Water Reactor; HWR: Heavy Water Reactor (including Candu); WWER: Russian PWR; RBMK: Russian design using graphite and water; FBR: Fast Breeder Reactor; GCR: Gas-Cooled Reactor.
3. Figures for Canada do not include four units (2568MW) closed in the 1990s but which may be refurbished and re-opened.
4. Figures for USA do not include one unit (1065MW) closed in 1985 but expected to be re-opened in 2007.

Table 1.2 Learning rates of selected energy technologies

Technology	Period	Learning rate (%)
Wind – OECD	1981-95	17
Solar – PV – World	1985-95	32
Gas Turbine Combined Cycle Power Plants – OECD	1984-94	34
Nuclear Power – OECD	1975-93	6

Source: McDonald, A. and Schrattenholzer, L. 'Learning rates for energy technologies' Energy Policy 29, 2001, pp. 255-261

Furthermore, one of the cost and financing papers prepared for the Stern Report (the UK Government's review of the economic impact of climate change) stated that:

*The costs of energy production and use from all technologies have fallen systematically with innovation and scale economies in manufacture and use, apart from nuclear power since the 1970s.*⁷

Various reasons have been put forward for the relatively low learning rate of nuclear power, including the relatively small post 1970s reactor ordering rate, the interface between the complexity of nuclear power plant and the regulatory and political processes and the variety of designs deployed⁸. While some of these factors may be overcome in the future, the UK Government's Performance and Innovation Unit also highlighted a number of areas in which future nuclear power plants may not exhibit comparable learning rates to other technologies, including:

- Nuclear power is a relatively mature technology and therefore dramatic 'technological stretch' is less likely than in other technologies;
- The relatively long lead times for construction and commissioning mean that improvements derived by feeding back information from operating and design experiences on the first units are necessarily slow; and
- The scope for economies of scale is less in the nuclear case than for renewables, due to the latter's smaller initial scale and wider potential application.

Longer construction

Analysis undertaken by the World Energy Council⁹ has shown the global trend in increasing construction times for nuclear reactors (see Table 1.3). The significant increase in construction times from the late 1980s until 2000 was in part due to changes in political and public views of nuclear energy following the Chernobyl accident with subsequent alterations in the regulatory requirements. More recent improvements in construction times reflect the inclusion of regulatory changes from the design stage, but still leave construction of new nuclear power plants averaging around seven years.

These increases in construction times can be seen in various countries across the world. In Germany, in the period 1965 to 1976 construction took 76 months, increasing to 110 months in the period 1983 to 1989. In

Japan average construction time in the period 1965 to 2004 was in the range of 44-51 months, but in 1995 to 2000 the average was 61 months. Finally in Russia, the average construction time from 1965 to 1976 was 57 months, then from 1977 to 1993 it was between 72 and 89 months, but the four plants that have been completed since then have taken around 180 months (15 years)¹⁰, due to increased opposition following the Chernobyl accident and the political changes after 1992.

Table 1.3 Construction time of nuclear power plants worldwide

Period of reference	Number of reactors	Average construction time (months)
1965-1970	48	60
1971-1976	112	66
1977-1982	109	80
1983-1988	151	98
1995-2000	28	116
2001-2005	18	82

Source: Clerici (2006): European Regional Study Group, the Future Role of Nuclear Energy in Europe, World Energy Council, Alexandro Clerici, ABB Italy, 13th June 2006 and for post 2000 figures, calculation based on PRIS database, <http://www.iaea.org/programmes/a2/index.html>

Economic impacts

Construction cost and construction time are intimately linked. An increase in construction time is likely to be a symptom of problems with construction that will lead to a cost increase. A delay in construction will increase costs, if only because 'interest during construction' on the capital borrowed will increase. The economic performance of nuclear power is heavily dependent on the construction costs. Therefore delays in construction have had a significant impact on the economics of nuclear power. These economic problems can be seen in different regions around the world.

Asia - India

Much of the current global nuclear energy construction is in India, where 7 of the 22 actively under construction are sited. Furthermore, with seven reactors completed since the turn of the century, India is clearly the country with most recent experience in nuclear construction. However, as Table 1.4 shows, the capital costs of construction in India have run considerably over budget.

North America - United States

The United States has the largest nuclear fleet in the world, with 103 reactors in operation. A further 28 have been closed and construction was stopped on an additional 67 units. However, it is now over 30 years since a nuclear reactor was ordered and subsequently completed in the United States. Although there is no doubt that the accident at Three Mile Island in 1979 was partially responsible for the drying up and cancelling of orders, many of the problems began prior to the accident. In particular, cost over-runs and delays in the construction of reactors were already evident prior to 1979.

Table 1.4

Station	Original cost estimate (Rs Crores)	Revised cost (Rs Crores)	Criticality year	Relative cost increase (%)
RAPS I	339.5	732.7	1972	216
RAPS II	5816	1,025.4	1980	176
MAPS I	617.8	1,188.3	1983	192
MAPS II	706.3	1,270.4	1985	179
NAPS I and II	2,098.9	7,450	1989 and 1991	354
Kakrapar I and II	3825	13,350	1992 and 1995	349
Kaiga I and II	7307.2	2,8960	1999 and 2000	396
RAPS III and IV	7115.7	2,5110	2000	353
Tarapur III and IV	24,275.1	62,000	2006	255

Note: Rs Crores = 10 million Rupees

According to data published by the US Department of Energy (DOE) the total estimated cost of 75 of the reactors currently in operation was \$45bn. The actual costs turned out to be \$145bn. This \$100bn (€76bn) cost overrun was more than 200% above the initial cost estimates¹²

Western Europe - UK

The UK Trade and Industry Committee stated in its 2006 report that 'Even the most optimistic estimates for this [new construction] are in the region of five years', but that 'Experience in the UK to date has shown it can take much longer, with an average construction period for existing nuclear power stations of almost 11 years.' The most recent reactor, a PWR at Sizewell B, experienced increases in capital costs from £1,691m to £3,700m,¹³ (€2,485m to €5,436m) while the construction costs of the Torness AGR nuclear reactor in Scotland increased from £742m (€1,089m) to a final cost of £2,500m (€3,673m).¹⁴

Nuclear cost over-runs and delays have not been restricted to nuclear power plants. At the time of the public inquiry in 1977 for the Thermal Oxide Reprocessing Plant (THORP) at Sellafield the expected cost was £300m (€440m). Furthermore, it was originally due to start operating in 1987, but by its completion in 1992 costs had risen to £1.8bn (€2.6bn). If the additional costs of associated facilities not originally planned for, including new waste treatment buildings, are included, the total bill reaches £2.8bn (€4.1bn).¹⁵

Central Europe - Czech Republic

In 1987 construction began on four blocks at the Temelin nuclear power plant in the Czech Republic. However, following the political changes in 1989 this was eventually reduced to two reactors. The Temelin reactors were eventually completed in 2002 and 2003, after 15 years of construction, using Westinghouse instrument and control technology.

Political and technological changes significantly disrupted the construction schedule as can be seen in Table 1.5, based on Czech Government figures, and the reactors were eventually completed around ten years late and five times over budget.

Table 1.5: History of Temelin cost over-runs

Year of announcement	Total budget (billion CZK)	Expected year of start-up
1981	20	
1985	35	1991
1990	50	1992
1993	68	1995
1995	72	1997
1996	79	1998
1997	85	1999
1998	99	2001

The International Energy Agency has suggested that 'despite low operating costs, amortising Temelin's costs (total cost: CZK99 billion, plus CZK10 billion of unamortised interest) will create a significant financial burden for CEZ'.¹⁶

Declining construction

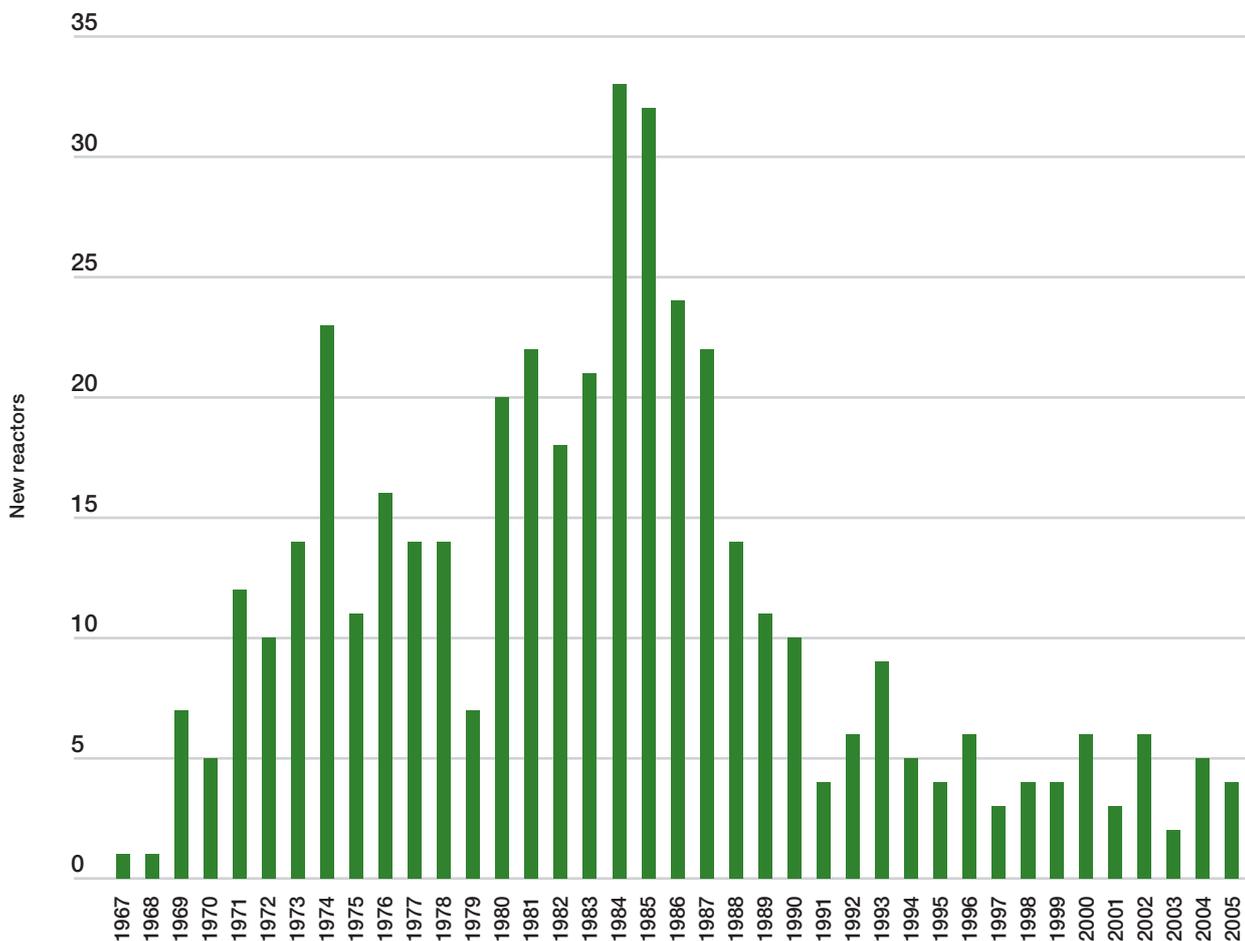
The last decade has seen a decline in construction of new nuclear power plants. Figure 1.1 shows the extent of this decline, from a peak in the 1980s of over 30GW of new capacity per year, to an average of 4GW per year over the last decade.

This decline impacts upon the experience the nuclear industry can bring to new projects. The European Investment Bank noted that 'very few nuclear power stations have been built in the last few years and thus the cost of recent plants does not seem a good reference to assess future costs. Additionally, any future development of nuclear energy will be based on the new generation of reactors and the cost of the new generation is uncertain at this stage'.¹⁸

The MIT study summarises the current experiences with new build:¹⁹

- Construction costs in Europe and North America in the 1980s and early 1990s were very high;
- The reasons for this poor historical construction costs experience are not well understood;
- Construction on few nuclear power plants has started and completed anywhere in the world in recent years;
- Information available about the true costs of building nuclear plants in recent years is limited;

Figure 1.1 Installation of new nuclear capacity onto grid



- The spectre of high construction costs has been a major factor leading to very little credible commercial interest in investments in new nuclear power plants; and
- The historical experience produced higher costs than predicted today by the few utilities now building nuclear power plants and by the nuclear industry in general.

The current order book

There has been considerable discussion recently of a 'nuclear revival'. While the possibility of new nuclear power orders is being discussed, at least in principle, in a number of countries, this revived interest has yet to be reflected in orders for new plants. This section examines the existing nuclear order book to see how much can be learnt from these plants, in particular whether new designs can overcome the economic problems suffered by earlier designs; and asks what barriers might exist that would prevent this renewed interest being turned into new nuclear orders.

A nuclear revival or decline?

The current list of plants under construction (see Table 1.6) is a short one. Sixteen of the 22 units are being supplied by vendors from China, Russia and India. It seems unlikely

that any of these vendors would be considered in Western Europe or North America, the markets that would need new orders if a global nuclear revival were to take place. Most of India's plants are largely based on a Canadian design from the 1960s, long since superseded in Canada. China's plants are also closely modelled on old Western designs – prior to the AP1000 order – albeit not so out-of-date as the Indian plants. China will probably continue to supply mainly its home market with one or two exports to Pakistan.

Minatom is seeking to export plants and was considered in the tender for the Olkiluoto order from Finland in 2004. The Russian industry is also heavily involved in 'hang-over' orders domestically and in Bulgaria, Slovakia and the Ukraine, where attempts are being made to revive construction on plants which were ordered in the 1980s but on which construction was halted or slowed around 1990. It is not clear how far renewed construction efforts would involve an upgrading of the designs to current standards. Atomstroyexport orders in Bulgaria, China, India and probably in Iran, involve more recent designs that are likely to be closer to meeting current safety standards. However, the continuing stigma of the Chernobyl disaster that is attributed to Russian design would still make an order for Russian technology in the West highly contentious even if the latest Russian design were to pass the safety regulatory hurdles.

Table 1.6: Nuclear power plants under construction or on order worldwide

Country	Site	Reactor type	Vendor	Size MW	Construction start	Construction stage (%)	Expected operation
Under construction:							
China	Tianwan 2	WWER	Russia	1,000	2000	100	2006
China	Lingao 3	PWR	China	1,000	2005	n/a	2010
China	Lingao 4	PWR	China	1,000	2006	n/a	2011
China	Qinshan 2-3	PWR	China	610	2006	n/a	2011
Taiwan	Lungmen 1	ABWR	GE	1,300	1999	57	2009
Taiwan	Lungmen 2	ABWR	GE	1,300	1999	57	2010
Finland	Olkiluoto 3	EPR	Areva	1,600	2005	n/a	2010
India	Kaiga 3	Candu	India	202	2002	45	2007
India	Kaiga 4	Candu	India	202	2002	28	2007
India	Kudankulam 1	WWER	Russia	917	2002	40	2008
India	Kudankulam 2	WWER	Russia	917	2002	40	2009
India	PFBR	FBR	India	470	2005	0	n/a
India	Rajasthan 5	Candu	India	202	2002	34	2007
India	Rajasthan 6	Candu	India	202	2003	19	2007
Iran	Bushehr	WWER	Russia	915	1975	75	2006?
Japan	Tomari 3	PWR	Mitsubishi	866	2004	28	2009
Korea	Shin-Kori 1	PWR	KSNP	1,000	2006	n/a	2010
Pakistan	Chasnupp 2	PWR	China	300	2005	n/a	2011
Romania	Cernavoda 2	Candu	AECL	655	1983	71	2007
Russia	Balakovo 5	WWER	Russia	950	1987	n/a	2011
Russia	Kalinin 4	WWER	Russia	950	1986	n/a	2011
Russia	Volgodonsk 2	WWER	Russia	950	1983	n/a	2009
TOTAL				17,608			
On order:							
China	Sanmen 1	AP1000	Westinghouse	1,100	n/a	0	n/a
China	Sanmen 2	AP1000	Westinghouse	1,100	n/a	0	n/a
China	Yangjiang 1	AP1000	Westinghouse	1,100	n/a	0	n/a
China	Yangjiang 2	AP1000	Westinghouse	1,100	n/a	0	n/a

Sources: PRIS database (<http://www.iaea.org/programmes/a2/index.html>), Nuclear News, World list of nuclear plants

In terms of markets, 17 of the 22 units are located in Asia, eight of these in the Pacific Rim and eight in the Indian sub-continent. The only current orders for Western vendors are the long-delayed Lungmen plant in Taiwan (which uses a current design, albeit one first ordered 15 years ago), the Olkiluoto plant in Finland and four orders, placed in December 2006, after a lengthy delay, for China.

Hang-over plants

Of the plants under construction, 5 were ordered 20 or more years ago. Construction is reported to still be underway, although in some cases, for example Russia, it is difficult to get independent confirmation that substantive work really is taking place. Work on a further 14 units has stopped (see Table 1.7) and while there are frequent reports that work may restart at these sites, it is far from clear if and when this will happen. Completion of these hang-over plants has a number of apparent attractions to the public in these countries:

- Construction on these plants often seems visually more advanced than it actually is (the shell is completed before the internal work is carried out) and it appears that just a little more investment will bring them on-line;

- For plants in Eastern Europe and the former Soviet Union, completion of these units appears likely to allow apparently lucrative exports of power; and
- Completion of the plants in Slovakia (Mochovce) and Bulgaria (Belene) will replace the power produced by nuclear plants that had to be closed (Bohunice and Kozloduy respectively) as a condition of the Accession Treaties to the European Union.

However, these ‘hangover’ plants raise a number of issues:

- The designs on which these orders were originally based are now well out of date. If completion to standards significantly below those currently applied was not acceptable, the cost of upgrading could be large and could counterbalance the benefit of the work already done, as occurred at the Temelin nuclear power plant in Czech Republic;
- Much of the equipment already bought has been in store, untouched, for at least 15 years. If this has not been stored to the highest standards, it could require expensive remedial work or even replacement; and
- There must be issues about the quality of work carried out so far. Demonstrating that existing work is up to standard will be expensive, and if it proves not to be up to standard, remedial work could be prohibitively expensive.

Table 1.7: Nuclear power plants on which construction has been stopped

Country	Site	Tech	Vendor	Size MW net	Construction start	Construction %
Argentina	Atucha 2	HWR	Siemens	692	1981	80
Bulgaria	Belene	WWER	Russia	1000	1987	40
Bulgaria	Belene	WWER	Russia	1000	1987	40
Brazil	Angra 3	PWR	Siemens	1275	1976	30
N Korea	Kedo 1	PWR	S Korea	1000	1997	33
N Korea	Kedo 2	PWR	S Korea	1000	1997	33
Romania	Cernavoda 3	Candu	AECL	655	1983	10
Romania	Cernavoda 4	Candu	AECL	655	1983	8
Romania	Cernavoda 5	Candu	AECL	655	1983	8
Russia	Kursk 5	RBMK	Russia	925	1985	70
Slovakia	Mochovce 3	WWER	Russia	405	1983	50
Slovakia	Mochovce 4	WWER	Russia	405	1983	40
Ukraine	Khmelnitsky 3	WWER	Russia	950	1986	15
Ukraine	Khmelnitsky 4	WWER	Russia	950	1987	15
TOTAL				11567		

Sources: PRIS database (<http://www.iaea.org/programmes/a2/index.html>), Nuclear News, World list of nuclear plants

Bulgaria

The orders for Belene, for two 1000MW Russian WWER units were placed in 1987 but construction was stopped in 1991 with a reported 45% of the work done. A tender to complete two units was recently launched. In 2006, it was announced that a Russian based company, Atomstroyexport, in collaboration with Areva and Siemens, offering a later design of WWER-1000, the AES-92, beat competition to win the order, with a construction contract of about €4bn.

A Skoda-led consortium, also offering a WWER-1000 design of an earlier vintage was the main opposition. It is not clear how far it will be possible to use the latest design (AES-92) given that about 45% of the work has been completed using the earlier design (AES-87). As part of the agreement, it has been reported that Atomstroyexport could buy back equipment previously used at the Belene site. After an examination, this equipment would be transferred to Russia and used at the construction site of the fourth power-generating unit for the Kalinin nuclear power plant.

However, it is still far from certain that the orders will be placed. Two particular problems are the ability to finance the orders and the extent to which placing the order will adversely affect the credit rating of the owner of the plant.

Private Western banks have been reluctant to finance the order and by November 2006, it seemed likely that Russian finance provided by the government and possibly a Euratom loan were the only credible option. The order was not well-received by the financial community and Standard & Poors' credit outlook for the Bulgarian electric utility, NEK, that would own the plant, was cut from 'developing' to 'negative'²⁰.

Slovakia

In 1983, orders were placed for four WWER-440 units to be built at the Mochovce site. Construction was halted in 1990 with units 1 and 2 reported to be 90% and 75% complete respectively, while the third and fourth units were reported to be only 40% and 30% complete. Work on the first two units recommenced in 1995 led by a consortium of Siemens,

Framatome and Czech and Slovak companies and the units entered commercial operation in 1998 and 1999.

The cost of completing the plants is not known but the fact that it took 3-4 years to finish plants that were said to be already 75-90% complete suggests the process was far from smooth. The problems appear to have been even worse in the Czech Republic where completion of two WWER-1000 units at Temelin, reportedly 50% complete when work restarted took in 1994, took 8-9 years and a substantial cost over-run before the units came on line. The reliability of both the Mochovce and Temelin plants has been mediocre.

The completion of units 3 and 4 at Mochovce was part of the deal that saw the Italian utility, ENEL, take control (with 66% of the stock) of the main Slovak generator, Slovenske Elektrarne (SE) in May 2006. According to ENEL and various national politicians the completion date for the reactors is 2011-12. ENEL is expected to finalise a feasibility study in April 2007 and then take a final decision whether or not it will invest in the units.

Russia

Russian nuclear sites remain largely closed to international and press scrutiny and it is difficult to get independent information on the four units reported by the IAEA to be under construction. There were reports, not officially confirmed, that the Kursk 5 unit, the only plant under construction that uses the Chernobyl (RBMK) technology, would not be completed. The fact that equipment from Belene is expected to be shipped to Kalinin for use in completion of unit 4 there suggests construction is not far advanced on Kalinin 4.

Argentina

Construction of the Atucha 2 HWR plant, a one-off design ordered from Siemens, was started in 1981, but was plagued by financial shortages and was suspended in 1994, apparently 80% complete. In August 2006, it was announced that investigations were under way to restart work. Despite the apparently high level of construction, completion would take up to four years and cost \$600m²¹ (€457m). Work would be carried out by the Canadian CANDU supplier, AECL. In November 2006

Table 1.8: Possible orders in the next 2-3 years

Buyer	Site	Bidders	Need	Possible order date	Forecast completion
France	Flamanville 3	Areva (EPR)	1x1600MW	2007	2012
Korea	Shin-Kori 2	Korea (KSNP)	1000MW	2006	2012
Korea	Shin-Kori 3 and 4	Korea (APR-1400)	2x1400MW	2008	2014
Korea	Shin-Wolsong 1 and 2	Korea	2x960MW	2006	2012
Japan	Tsuruga 3 and 4	Mitsubishi (APWR)	2x1500MW	2007	2014
USA	Various	Various	6-8 units	2008	n/a

Source: Various press reports

AECL signed an agreement with Nucleoeléctrica Argentina S.A for the upgrading of the country's other reactor at Embalse and the completion of Atucha 2, however, no financial details or timetable were published.²²

Brazil

In 1976, Brazil signed a deal with Siemens for the supply of up to 8 units of 1300MW. Work on two of these was started, but continually delayed and the first unit, Angra 2, only came on line in 2000. Efforts began then to restart work on the second unit, Angra 3, estimated to cost about \$3bn (€2.5bn). Little construction work had been carried although most of the equipment had been bought and delivered, but 6 years later work had still not re-started.

Iran

Construction started at the Bushehr reactors in 1975/6. Originally, these were Siemens KWU designed 1293 MW light water reactors. However, following the Islamic revolution, work was abandoned in 1979.

In August 1992 a Russian-Iranian agreement was signed to complete the reactors. This was followed in 1994 with Russian experts moving onto site in Iran and in 1998 a timetable for the completion of the reactors was agreed. At the time it was envisaged that unit 1 would be completed in 52 months. Currently, the reactor is due to start up as a VVER 1000 reactor in late 2007 with commercial operation in 2008. The Atomic Energy Organisation of Iran has announced that construction of Unit 2 will proceed. All the fuel for the reactor will be supplied from Russia, and it is intended that the used fuel will be returned there.

Romania

A deal was originally signed in 1978 for supply by the Canadian vendor, AECL, of five reactors. The actual orders were delayed and problems of finance slowed work on the units from the start. By 1990, the first unit was reported to be less than 50% complete. This unit was finally completed in 1996, by which time, unit 2 was only 25% complete and construction had been halted. Work re-started on unit 2 but completion is still scheduled for later this year. For units 3-5, civil work has been carried out but no equipment has been purchased yet. In mid-2006 a scoping study for the Environmental Impact Assessment was issued for the completion of units 3 and 4. A financial assessment is currently (early 2007) underway. Building these plants would effectively be from scratch and, even on the optimistic current timetables, the plants would not come on-line before 2015.

New orders

For a so-called nuclear 'renaissance', these hang-over plants are of little relevance. A nuclear renaissance must be based on impartial decisions by utilities and governments, with strong support from the public, that new nuclear orders are a safe, sustainable and cost-effective way of generating electricity. Table 1.8 shows that few orders can be expected in the next couple of years.

China

For more than 25 years, China has been one of the main prospective markets for Western nuclear power vendors, with China frequently projecting a large expansion in its nuclear capacity. However, since the first order was placed in 1987 (five years after the order was expected to be placed), only 6 units (5GW) have been ordered from international vendors with a further 8 units (5GW) bought from Chinese vendors.

In September 2004, China invited bids for four nuclear units of about 1,000MW, two at Sanmen and two at Yangjiang. At that time the Chinese government planned to construct a further 32 reactors by 2020, each with a capacity of 1,000MW. It was then expected the orders would be placed in late 2005. One of the difficulties in the negotiations was the extent of the technology transfer demanded. In March 2006, Nucleonics Week reported²³:

Les Echos said in its March 15 edition that the French vendor had refused to match Westinghouse's offer to sell the Chinese the blueprints for the AP1000 design. Areva had submitted a seventh bid in early February that featured more technology transfer, but was unwilling to go further, the sources said.

Finally, in December 2006, the Westinghouse AP1000 was chosen for these four orders. For the future, orders will probably continue to be fewer than forecast by the Chinese Government and will be placed with Chinese companies where possible. It is therefore unlikely that China will develop as a large market for Western nuclear vendors.

South Korea

As in Taiwan, the increasingly democratic and open regime in Korea has resulted in much slower progress with nuclear orders than expected and than was achieved in the 1990s. During the past two decades, Korea has tried to build up an independent reactor supply capability using technology originally licensed from US company Combustion Engineering. Combustion Engineering's nuclear business was taken over by the European

Box 1: Experience with the Framatome N4 design

The N4 design was promoted in the early 1980s when it was announced as the first all-French design of PWR bringing together more than a decade of building and operating PWRs. The previous 55 PWRs had all been based much more closely on the Westinghouse design licensed by Framatome. However, from the start, things went wrong. Far from being cheaper than its predecessors, EDF had to negotiate hard with Framatome to avoid having to pay more per kW of capacity than it had paid for earlier reactors. For the first time in the French PWR programme, the period from placing of order to first criticality took more than six years, with the N4 units taking between six and twelve years each to build.

Problems continued when the plants started up and a series of technical problems led to the period between first criticality and commercial operation, usually a few months, taking from 29-49 months. Reliability in this period was very poor and the average load factor for these four units for the first four calendar years after criticality was only 46%. Since commercial operation, the average load factor to the end of 2005 was 78%, a considerable improvement but below the world average (79%) and well below the levels most Western countries achieve.

	Start construction	Order	Criticality	Commercial operation	Load factor for first four years (%)
Chooz B1	1/84	4/84	8/96	5/2000	40.4
Chooz B2	12/85	1/87	4/97	9/2000	37.2
Civaux 1	10/88	6/91	12/97	1/2002	45.9
Civaux 2	4/91	1/93	12/99	4/2002	60.0

Sources: IAEA PRIS data base <http://www.iaea.org/programmes/a2/index.html> except for order dates, Nucleonics Week (various)

company, ABB, in the early 1990s. ABB's nuclear division was, in turn, taken over by BNFL in 2000 and merged with its Westinghouse division, which, itself, was taken over by Toshiba in 2006. Most of the recent orders have used a 1000MW design, but for the future, orders are likely to be for the APR-1400, based on the System 80+ design developed by Combustion Engineering in the 1980s which received US regulatory approval in principle in 1997. After long delays, the first orders for this new design might be placed in 2008.

Japan

Ordering in Japan has slowed markedly in the past decade and only one plant is under construction. As has always been the case in the past, a number of sites are listed as likely to host new nuclear power plants and the World Nuclear Association, in September 2006, listed 11 plants on which construction was expected to start in the next 5 years. However, on past experience, this will not be fulfilled. The list includes a plant at Ohma which was to be ordered in 2006 and two units at Tsuruga to be ordered in 2007. The unit at Ohma appears still to be in the planning stage, several years away from being ordered, while the Tsuruga order has been expected to be placed within a year for about 5 years now and completion (2014) is already 5 years behind the original schedule.

France

France has long been seen as the one country in Western Europe where new nuclear orders were clearly still viable. However, the very high proportion of French electricity already produced by nuclear sources (about 80%) has meant there has been little scope for orders in the past 15 years. France already exports a large amount of electricity and is still unable always to use the full potential output of its nuclear plants, resulting in a need to 'load-follow'²⁴. The construction of new reactors in France would therefore add to the current overcapacity and would have to be accompanied with measures to enable further export, the closure of existing reactors or further measures to 'load-follow'.

In addition, France's experience with its most recent orders, the four orders for the 'N4' design, was poor (see Box 1). This was a design that was supposed to build on previous experience and solve problems in previous designs. Not surprisingly, the N4 design has been quietly forgotten for future orders and replaced by the European Pressurised Water Reactor (EPR), based on the N4 and German Konvoi designs. This too has suffered delays and the first order might be placed in 2007 (as is usual in France, site work has begun ahead of receiving all necessary consents) for a unit to be built at the Flamanville site. The Chinese order for the AP1000 design and the technical and licensing problems at the Olkiluoto 3 reactor under construction in Finland (see later), leading to significant cost over-runs, will increase costs to EdF. EdF has been trying to find co-investors, but its main targets, ENEL and German utilities, have so far not committed themselves to participate in the project. Furthermore, Anne Lauvergeon, the CEO of Areva, acknowledged that the EPR might be too big for many markets at the announcement of an agreement between Areva and Mitsubishi to work on a smaller reactor design.²⁵ The Flamanville-3 project is also facing political uncertainty, given the opposition of the Socialist presidential candidate Royal to the construction of an EPR in France. There appear to be no firm plans for any follow-up orders.

USA

There is a possibility that orders for new nuclear plants will be placed in the USA in the next 2-3 years, but there are many possible sites, buyers and vendors contending for the limited but essential subsidies available under the 2005 legislation, and it is difficult to predict which are the most likely sites for new orders.

For more information see Part 3, 'USA'.

Generation III/III+ plants: experience and status

The most relevant designs for orders to be placed in the next decade in the West are so-called Generation III and Generation

III+ designs. The main distinction between Generation II plants and Generation III and III+ plants claimed by the industry is that the latter incorporate a greater level of 'passive' compared to engineered safety. This is contradicted by a report released by Greenpeace International, 'Nuclear reactor hazards' which argues that some of these technological changes are unproven and that relying on them could compromise safety²⁶. For example, Generation III and III+ designs would rely for emergency cooling less on engineered systems and more on natural processes, such as convection. A large number of designs have been announced, but many are not far advanced, do not have regulatory approval and have limited prospects for ordering. There is no clear definition of what constitutes a Generation III design, apart from it being designed in the last 15 years, but the main common features claimed by the nuclear industry are:

- a standardised design to expedite licensing, and reduce capital cost and construction time;
- a simpler and more rugged design, making them easier to operate and less vulnerable to operational upsets;
- higher availability and longer operating life - typically 60 years;
- reduced possibility of core melt accidents;
- minimal effect on the environment;
- higher burn-up to reduce fuel use and the amount of waste; and
- burnable absorbers ('poisons') to extend fuel life.²⁷

Whether the new designs will actually achieve their stated objectives, for example in improved safety, remains to be seen. The characteristics listed are clearly very imprecise and do not define well what a Generation III plant is other than that the design was evolved from existing models of PWR, BWR and Candu. The distinction between Generation III and III+ designs is even more unclear, with the US Department of Energy saying only that III+ designs offer advances in safety and economics over III designs.

Pressurised Water Reactors (PWRs)

European Pressurised Water Reactor (EPR)

The only Generation III+ PWR yet ordered, apart from the four orders placed by China in December 2006, is the Areva European Pressurised Water Reactor (EPR), for the Olkiluoto site in Finland. The EPR (III+) has an output of 1,600MW although this may be increased to 1,750MW for orders after Olkiluoto. The design was developed from the previous Framatome design, N4, with some input from Siemens' (which has a 34% stake in Areva NP (Framatome)) previous design, the 'Konvoi' plant. A reduction in the refuelling time is assumed by the industry to allow a load factor²⁸ of about 90%.

The Finnish Government issued a construction license in February 2005 and construction started in summer 2005. The EPR has also been bid for orders in China, but the tender was

awarded to the Westinghouse AP1000 in December 2006. France intends to build at least one EPR (at Flamanville) and perhaps five successor units, but these plans, especially for the successor plants, are not yet firm. The EPR received safety approval from the French authorities in September 2004 and from the Finnish authorities in January 2005.

Areva, as part of the Unistar consortium with US utility Constellation Energy, has asked the US Nuclear Regulatory Commission (NRC) to begin licensing of the EPR in the USA under the US Government's 'Nuclear Power 2010' programme. Constellation Energy has identified two sites housing existing reactors that might host an EPR. For the US market, EPR will be an acronym for Evolutionary Power Reactor.

The US Nuclear Regulatory Commission's current review schedule shows the US EPR design certification review being completed by mid-2011, although Unistar hopes that the review can be completed about a year earlier.

It is not clear what the consequences would be if the US NRC was to demand significant modifications to the design approved for use in Europe. Politically, for European countries to be building a design apparently not regarded as safe enough for the USA would raise serious concerns. Any modifications could also have significant cost consequences. Experience licensing the AP600 is relevant. By the time the AP600 had met all the requirements imposed by the NRC and a license had been given, the design had become uneconomic (see below).

AP1000

The AP1000 (Advanced Passive) is a Generation III+ plant designed by Westinghouse and developed from the AP600 design (Generation III). The rationale for the AP600 was to increase reliance on passive safety and also that scale economies (from building larger units as opposed to building larger numbers) had been over-estimated. An executive of Westinghouse justified the choice of a unit size of 600MW rather than 1,000-1,300MW by stating that 'the economies of scale are no longer operative'.²⁹ The AP600 went through the US regulatory process and was given safety approval in 1999 after a 10 year procedure. By then, it was clear that the design would not be economic and the AP600 was never offered in tenders. Its size was increased to about 1,150MW ironically in the hope that scale economies would make the design competitive. Westinghouse stated:

*Westinghouse recognized that the current estimate of 4.1 to 4.6¢/kWh for the AP600 is not competitive in the US market. It, therefore, embarked on the development of the AP1000, which applies economies of scale to passive safety plants to reduce the cost per kWh to an estimated 3.0 to 3.5¢/kWh.*³⁰

In September 2004, the US Nuclear Regulatory Commission

(NRC) granted a Final Design Approval (FDA), valid for 5 years, to Westinghouse for the AP1000. The NRC issued a standard Design Certification, valid for 15 years in January 2006. The licensing process took about four years despite the fact that the AP1000 was, according to the NRC 'based closely on the AP600 design that NRC certified on December 16, 1999'³¹.

The AP1000's modular design is asserted to allow it to be built in 36 months at a cost of \$1200/kW. However, until details of actual bid costs are available and until units are built, these figures are assertions from an industry with a long history of cost overruns³².

AP1000 has so far been offered in only one call for tenders, the call for four Generation III units for China placed in 2004, which it won in December 2006. Five US utilities (Duke, TVA, Progress, SCANA and Southern) have chosen the AP1000 as the basis for 'Nuclear Power 2010' bids.

AP1000 is seen as an option in Europe, particularly in the UK, but no significant work has yet been carried out by any of the European nuclear regulatory authorities assessing its licensability. As with the EPR in the USA, this lack of progress with licensing is a risk and means that the AP1000 is not an option for ordering in Europe for at least the 5 years it would take to get safety approval.

System 80+/APR-1400

Combustion Engineering's System 80+ design (Generation III) received regulatory approval in the USA in 1997 when Combustion Engineering was owned by ABB. ABB (including the Combustion Engineering nuclear division) was subsequently taken over by BNFL and was absorbed into its Westinghouse division, which in turn, was taken over in 2006 by the Japanese company, Toshiba. The System 80+ has not been offered for sale by Westinghouse. However, the Korean vendor, Doosan, has used this design under license from Westinghouse to develop its APR-1400, which is expected to be ordered for Korea in 2008. Korea did try to offer the design for the tender for Generation III plants for China won by the AP1000, but it was rejected. It seems unlikely that the APR-1400 will be offered in Western markets at least in the next decade.

Advanced Pressurised Water Reactor (APWR)

Development of the Advanced PWR (APWR), Generation III, by Mitsubishi and its technology licensor, Westinghouse, was launched at about the same time as the ABWR (see below) about 15 years ago but ordering has fallen far behind that for the ABWR and first orders might be placed in 2007 for two units (1,500MW) at Japan's Tsuruga site.

However, the sale of Westinghouse to its Japanese rival, Toshiba, appears to have caused a strategic rethink on the part of Mitsubishi and in June 2006, it announced it was seeking to

gain regulatory approval in the USA for a 1,700MW design based on the APWR. Mitsubishi expects to submit an application for license certification in December 2007 with possible certification by the end of 2011. However, NRC resources are stretched and with at least five designs ahead of it in the queue for licensing, this schedule could well not be achievable. In March 2007, TXU announced that it had reached a nonbinding deal under which TXU would use the Japanese company's design for up to three potential nuclear reactors in Texas. Mitsubishi is discussing with General Electric forming a partnership to sell the APWR in the USA. It is not clear whether the APWR that would be offered in the USA should be classed as a Generation III or III+ design.

AES-91 and AES-92 WWER-1000

These are the latest Russian designs offered by Atomstroyexport. The AES-91 is under construction in China (Tianwan) and was one of three designs short-listed for Olkiluoto. Finland has two earlier generation WWERs (at Loviisa) and because of its geopolitical position and previous experience with WWER technology, Finland considered the latest Russian design. The slightly more advanced AES-92 has two orders in India (Kudankulam) expected to enter service in 2007. Atomstroyexport bid unsuccessfully for four Chinese plants awarded to Westinghouse in 2006.

There is some confusion in the press about which designs are being built in China and India. Some reports list the Tianwan plants as using the AES-92 design and the Kudankulam plants as using the AES-91 design, but the consensus seems to be that the Kudankulam plants use the AES-92 design and the Tianwan plants use the AES-91 design."

Atomstroyexport won the order to complete the Belene plant (two units in Bulgaria) using a design based on the AES-92, although given that quite a lot of work had already been carried out at the site, it is not clear how far the plant (if built) would be categorised as an AES-87 design, as originally ordered, or an AES-92.

How far the AES-92 can be categorised as a Generation III plant is not clear and it seems unlikely it would be considered for any Western market other than Finland.

Boiling Water Reactors (BWRs)

Advanced Boiling Water Reactor (ABWR)

The ABWR (Generation III) was developed in Japan by Hitachi and Toshiba and their US technology licensor, General Electric (GE). The first two orders were placed in Japan around 1992 and completed in 1996/97. By end-2006, there were four ABWRs in service, all in Japan, and two under construction in Taiwan. Total construction costs for the first two Japanese units were reported to be \$3,236/kW (€2,465) for the first unit

in 1997 dollars and estimated to be about \$2,800/kW (€2133) for the second. These costs are well above the forecast range.³³ The ABWR received safety approval in the USA in 1997 and is being considered by two of the US utilities that may compete for US government subsidies under the Nuclear 2010 programme. The existence of four operating units in Japan is a useful demonstration of the technology. However, since the design has now apparently been superseded by the ESBWR (see below), buyers and regulators may be reluctant to sanction a design that is no longer state-of-the-art.

The operating units in Japan have suffered technical problems in 2006. In June, cracking was found in the blades of the turbines (supplied by Hitachi) of the Hamaoka 5 plant owned by Chubu Electric. Similar problems were found at the Shika 2 plant owned by Hokuriku Power. The problems were due to design faults in the turbine rather than problems with the nuclear island. A temporary repair might allow the plants back in service in 2007 operating at 10-15% below their design rating until new turbines can be supplied. This is likely to take several years while a new turbine design is completed, manufactured and installed. Operation at reduced power will cause large additional costs. It was not clear by the end of 2006 how far these costs would fall on the utilities and how far they would fall on Hitachi.³⁴

Economic and Simplified Boiling Water Reactor (ESBWR)

The Economic and Simplified BWR (ESBWR) is a 1,500MW design developed by GE and is described by GE as Generation III+. In October 2005, GE applied to the NRC for certification of the ESBWR design. The ESBWR has been developed in part from GE's Simplified Boiling Water Reactor (SBWR) and the ABWR. The SBWR began the process of getting regulatory approval in the 1990s but was withdrawn before the procedure was complete and did not win any orders. GE hopes to gain Final Design Approval for the ESBWR by the end of 2006 with certification following about a year later. The NRC had not forecast a completion date by October 2006, although it now appears likely certification will not be before 2009. Three US utilities are considering the ESBWR for their bids for subsidies under the Nuclear 2010 programme.

Other BWRs

A number of other designs have been developed, but none has received regulatory approval anywhere and only the SWR has been offered for sale. The main BWR designs include:

- The SWR, a 1,000-1,290MW design developed by Areva. This was one of the three designs short-listed for Olkiluoto; and
- The BWR-90+, a 1,500MW design developed by Westinghouse from the Asea BWR design

Candus

The Advanced Candu Reactor (ACR), Generation III+ was being developed in two sizes, ACR-700 (750MW) and ACR-1000 (1,100-1,200MW). The ACR-700 was being reviewed by the US NRC under the sponsorship of the US utility, Dominion, but Dominion withdrew its support in January 2005, opting instead for GE's ESBWR, citing the long time-scale of at least five years that NRC said would be needed for the review because of the lack of experience in the USA with Candu technology. As a result of Dominion's decision to drop the ACR-700 as its reference design, AECL says it will concentrate on ACR-1000. The most likely market for the ACR-1000 is Canada. British Energy, the UK nuclear utility, did participate in the development programme for ACR designs but the financial collapse of British Energy in 2002 ended its support.

High Temperature Gas Reactors (HTGRs)

The Pebble Bed Modular Reactor (PBMR), Generation III+, is based on designs developed by Siemens (HTR-Modul) and ABB (HTR-100) for Germany in the 1980s.³⁵ After poor experience with its Uentrop (THTR-300) HTGR plant, which operated very unreliably between 1983-89 before it was closed, ABB pooled its resources in HTGRs with those of Siemens to form a new company, HTR, in 1988 but this company failed to win any orders for the pooled design. This design is now being developed under license to HTR by South African interests. The various takeovers and mergers in the reactor vending business mean that the technology license providers are now Areva (for Siemens) and Westinghouse (for ABB). The technology is being developed by the PBMR Co, which had as partners Eskom, the publicly owned South African electric utility, BNFL and US utility Exelon as well as other South African interests. The project was first publicised in 1998 when it was expected that first commercial orders could be placed in 2003. However, greater than anticipated problems in completing the design, the withdrawal of Exelon, and uncertainties about the commitment of other partners, including Westinghouse, has meant that the project time-scale has slipped dramatically and first commercial orders cannot now be before 2014 even if there is no further slippage³⁶.

Chinese interests are also developing similar technology with the same technological roots and while optimistic statements have been made about development there, the Chinese Government seems to be backing development of PWRs and perhaps BWRs.

Another design of HTGR, the Gas Turbine Modular High Temperature Reactor (GT-MHR), is also under development, but there are no immediate prospects for orders.

Generation IV plants

A new optimism, in some policy arenas, about the future of nuclear power has revived the research into plutonium fuelled reactors, which are now categorised as Generation IV designs. Two international research programmes are underway to develop the Gen IV reactors, one launched by the United States in 2000, 'Generation IV International Forum' (GIF), the other launched by the International Atomic Energy Agency, '**International Project on Innovative Nuclear Reactors and Fuel Cycles**'. Globally the nuclear industry is aware that uranium reserves are relatively limited and for the medium to long term, another design of reactor needs to be developed that uses uranium more sparingly. According to the GIF, a closed fuel cycle is celebrated as a major advantage of Generation IV concepts because they argue that 'in the longer term, beyond 50 years, uranium resources availability also becomes a limiting fact, unless breakthroughs occur in mining or extraction technologies'.³⁷ The use of plutonium and the closed fuel cycle significantly increases the potential energy resource that can be obtained from a uranium atom and therefore in theory increase the longevity of the resource. This was the logic deployed in the 1970s and 1980s when fast breeders were being actively promoted. However, the collapse of nuclear orders, an increase in availability of uranium resources and the technology and economic problems of fast breeders and reprocessing have resulted in the continued deployment of only one reactor in Russia for electricity production.

There are six concepts for the development of Gen IV that have been selected for further development in the framework of GIF. Four of these use plutonium fuels (see box).

Technological gaps

The majority of the Generation IV reactors currently exist only on paper. In order for even prototype versions to be built, technological breakthroughs in material development will have to be made. This relates in particular to the ability of materials to withstand the high temperatures needed within the Generation IV designs. The GIF Road Map reports that for the lead-cooled fast reactor, gaps exist in the development of the systems and materials for the 550°C options, and large gaps for the 750-800°C options, with similar situations found in the other reactor design. Other major potential problems have been identified in the ability of the materials and structures to withstand the expected corrosion and stress cracking imposed by the reactor's conditions.

Some nuclear regulators in the US are not enthusiastic about the new reactor concepts. New nuclear power plants should be based on evolutionary, not revolutionary, technology, according to an NRC commissioner. The commissioner cautioned against

BOX 2: Six major designs of the Generation IV International Programme

GFR – Gas-Cooled Fast Reactor System: The GFR system is a helium-cooled reactor with fast-neutron spectrum and closed fuel cycle. It uses helium as coolant, due to extreme temperatures (850° C outlet; compared to 300° C for PWRs and 500°C for FBRs). Consequently, 'High temperatures and extreme radiation conditions are difficult challenges for fuels and materials'. It will use plutonium and burn actinides.

LFR – Lead-Cooled Fast Reactor System: LFR systems are reactors cooled by liquid metal (lead or lead/bismuth) with a fast-neutron spectrum and closed fuel cycle system. A full actinide recycle fuel cycle with central or regional facilities is envisaged. A wide range of unit sizes is planned, from 'batteries' of 50–150 MWe, and modular units of 300-400 MWe to large single plants of 1200 MWe. The LFR battery option is a small factory-built turnkey plant with very long core life (10 to 30 years). It is designed for small grids, and for developing countries that may not wish to deploy a fuel cycle infrastructure. Among the LFR concepts, this battery option is regarded as the best, concerning fulfilment of Generation IV goals. However, it also has the largest research needs and longest development time.

MSR – Molten Salt Reactor System: The MSR system is based on a thermal neutron spectrum and a closed fuel cycle. The uranium fuel is dissolved in the sodium fluoride salt coolant that circulates through graphite core channels. The heat, directly generated in the molten salt, is transferred to a secondary coolant system, and then through a tertiary heat exchanger to the power conversion system. It is primarily envisioned for electricity production and waste burn-down. The reference plant has a power level of 1,000 MWe. Coolant temperature is 700°C at very low pressure. Of all six reactor systems, MSR requires the highest costs for development (\$1bn/€761m).

SCWR – Supercritical-Water-Cooled Reactor System: The SCWRs are high-temperature, high-pressure water-cooled reactors that operate above the thermodynamic critical point of water (i.e. at pressures and temperatures at which there is no difference between liquid and vapour phase). The reference plant has a 1700 MWe power level, an operating pressure of 25 MPa, and a reactor outlet temperature of 550°C. Fuel is uranium oxide.

SFR – Sodium-Cooled Fast Reactor System: The SFR system consists of a fast-neutron reactor and a closed fuel cycle system. There are two major options: One is a medium size (150 to 500 MWe) reactor with metal alloy fuel, supported by a fuel cycle based on pyrometallurgical reprocessing in collocated facilities. The second is a medium to large (500 to 1,500 MWe) reactor with MOX fuel, supported by a fuel cycle based upon advanced aqueous reprocessing at a centralized location serving a number of reactors. According to GIF, the SFR has the broadest development base of all the Generation IV concepts.

VHTR – Very-High-Temperature Reactor System: The VHTR system uses a thermal neutron spectrum and a once-through uranium fuel cycle. The reference reactor concept has a 600-MWth graphite-moderated helium-cooled core based on either the prismatic block fuel of the GT-MHR or the pebble bed of the

'too much innovation' which would lead to new problems with untested designs, and urged the industry not to 'over promise' the capabilities of new reactor systems³⁹.

Different agencies suggest significantly different views about when these reactor types will be operational. President Chirac of France has stated that a prototype Generation IV reactor will be deployed in 2020, while the latest report by the US General Accounting office has concluded that the programme is unlikely to meet its 2021 deadline for deployment.⁴⁰ Many commentators suggest that 2030-5 is a realistic timetable given the technological hurdles still in place.

Economics

Given the technological uncertainties and timescales involved many questions remain over the economics of the Gen IV reactors.

The only Gen IV design that is based on previously commercial reactors is the sodium-cooled fast breeder (SFR). The GIF states that 'a key performance issue for the SFR is cost reduction to competitive levels. The extent of the technology base [is known] yet none of the SFRs constructed to date have been economical to build or operate.'⁴¹

The costs of the fuel cycle concepts –the use of reprocessing – required in most Gen IV designs would be very high. According to 'The Future of Nuclear Power' by the US Massachusetts Institute of Technology,⁴² a convincing case has not yet been made that the long term waste management benefits of advanced closed fuel cycles involving reprocessing of spent fuel are not outweighed by the short term risks and costs, including proliferation risks. Also, the MIT study found the fuel cost with a closed cycle, including waste storage and disposal charges, to be about 4.5 times the cost of a once-through cycle. Therefore it is not realistic to expect that new reactor and fuel cycle technologies that simultaneously overcome the problems of cost, safe waste disposal and proliferation will be developed and deployed for several decades, if ever.

Part 2:

Nuclear economics

From commercial nuclear power's beginnings, the promise of cheap power (infamously, 'power too cheap to meter') has been one of the main claims of the nuclear industry. As is amply demonstrated throughout this report, this promise of cheap power has seldom been kept. The nuclear industry continues to claim that a combination of learning from past mistakes and new, more cost-effective designs will, this time, allow the promise of cheap power to be fulfilled.

In the first part of this section, we examine the economics of nuclear power, in particular, identifying which are the most important factors in determining the cost of power from a nuclear power plant. In the second, we examine how liberalisation of electricity markets has adversely affected the prospects for nuclear power because, for the first time, the owners of the power plants will be financially responsible if power plants are not built to time and cost or are not reliable. This increased risk raises the cost of capital to the detriment of nuclear power because of its high construction costs. In the third section, we examine ways in which buyers are trying to cope with the extra risks they face, for example, by demanding fixed price ('turnkey') terms from plant suppliers.

In the fourth section, we examine the forecasts of the costs of power from new nuclear power plants that have been published in the past six years. In particular, we identify which of the assumptions are most important in producing optimistic estimates and we assess whether these assumptions are realistic. Finally, we examine approaches to forecasting variables over the very long periods of time a nuclear power plant is expected to operate.

Main determinants of nuclear power costs

There are several important determinants of the cost of electricity generated by a nuclear power plant. The usual rule-of-thumb in the past for nuclear power has always been that about two thirds of the generation cost is accounted for by fixed costs, that is, costs that will be incurred whether or not the plant is operated, and the rest by running costs. The main fixed costs are the cost of paying interest on the loans and repaying the capital, but the decommissioning cost is also included. The main running cost is the cost of operation, maintenance and repair, rather than the fuel cost. However, as is shown below, there is a huge degree of variance in the assumptions made for these parameters from forecast to forecast, so the broad split between fixed and variable cost should be seen as indicative.

Fixed costs

There are three main elements to the fixed cost per kilowatt hour: the construction cost; the cost of capital, which

determines how much it costs to borrow the money to build the plant; and the plant's reliability, which determines how much saleable output there is over which to spread the fixed costs. Construction cost is the most widely debated parameter. The cost of borrowing was always assumed to be lower because of the monopoly status of electricity industries but liberalization of electricity industries has led to much greater debate on this variable (see below). Reliability has improved significantly in recent years with performance finally reaching the levels forecast in many countries. However, experience with the most recent French design, the N4, shows good reliability cannot automatically be assumed (see Part 1).

Construction cost and time

Forecasts of construction cost differ by a factor of two or even three⁴³. A number of factors explain why there are such disparate forecasts of construction cost.

Many of the quoted construction cost forecasts should be treated with scepticism. The most reliable indicator of future costs has generally been past costs. However, most utilities are not required to publish properly audited construction costs, and have little incentive to present their performance in anything other than a good light. So utilities' reports of past costs must be treated with caution.

Prices quoted by those with a vested interest in the technology, such as promotional bodies, plant vendors (when not tied to a specific order) and utilities committed to nuclear power, clearly must be viewed with scepticism. Bid prices by vendors are more realistic than forecasts by international agencies because the companies could be called on to back up these forecasts. However, equipment purchases may represent less than half of the total cost. Civil engineering and installation, often contracted from bodies other than the nuclear power plant vendors, are generally a larger proportion. Problems in controlling the cost of site work have been the cause of cost escalation more often than poor cost estimation of individual components. Contract prices may also be subject to escalation clauses that mean the final price is significantly higher so even bids cannot be taken as reliable indicators of the final cost unless the equipment is supplied under 'turnkey' terms (i.e., the customer is guaranteed to pay only the contract price). As argued in Part 2, offering turnkey terms is a big risk for a vendor and genuine turnkey terms are rarely available.

Cost of capital

The real (net of inflation) cost of capital varies from country to country and from utility to utility, according to the 'country risk' (how financially stable the country is) and the credit-rating of the company. There will also be a huge impact on the cost of capital from the way in which the electricity sector is organised. If the sector is a regulated monopoly, the real cost of capital could be

as low as 5-8% but might be as high as 15% in a competitive electricity market, especially for nuclear power. Part 2, 'Impact of liberalisation of electricity industries', discusses in detail how liberalisation of electricity industries affects the cost of capital by shifting the risk from consumers to plant owners and builders.

Operating performance

Higher utilisation improves the economics of nuclear power because the large fixed costs can be spread over more saleable units of output than if utilisation is lower. In addition, nuclear power plants are physically inflexible. Frequent shutdowns or variations in output reduce both efficiency and the lifetime of components. As a result, nuclear power plants are operated on 'base-load' (continuously at full power) except in the very few countries (e.g., France) where the nuclear capacity represents such a high proportion of overall generating capacity that this is not possible. A good measure of the reliability of the plant and how effective it is at producing saleable output is the load factor (capacity factor in US parlance). The load factor is calculated as the output in a given period of time expressed as a percentage of the output that would have been produced if the unit had operated uninterrupted at its full design output level throughout the period concerned.⁴⁴ Unlike construction cost, load factor can be precisely and unequivocally measured and load factor tables are regularly published by trade publications such as *Nucleonics Week* and *Nuclear Engineering International*.

As with construction cost, load factors of operating plant have been much poorer than forecast. The assumption by vendors and those promoting the technology has been that nuclear plants would be extremely reliable with the only interruptions to service being for maintenance and refuelling (some designs of plant such as the AGR and Candu are refuelled continuously and need only shut down for maintenance) giving load factors of 85-95%. However, performance was poor and around 1980, the average load factor for all plants worldwide was about 60%. To illustrate the impact on the economics of nuclear power, if we assume fixed costs represent two thirds of the overall cost of power if the load factor is 90%, the overall cost would go up by a third if load factor was only 60%. To the extent that poor load factors are caused by equipment failures, the resulting additional cost would further increase the unit cost of power.

However, from the late 1980s onwards, the nuclear industry worldwide has made strenuous efforts to improve performance. Worldwide, load factors now average more than 80%. The USA has an annual average of about 90% compared to less than 60% in 1980, although the average lifetime load factor of America's nuclear power plants is still only 70%.

Only seven of the 414 operating reactors with at least a year's service and which have full performance records have a lifetime load factor in excess of 90% and only the top 100 plants have

a lifetime load factor of more than 80%. Interestingly, the top 13 plants are sited in only three countries, six in South Korea, five in Germany and two in Finland. This suggests that performance is not random but is determined more by the skills that are brought to bear and how well the plants are managed than by the technology and the supplier.

New reactor designs may emulate the level of reliability achieved by the top 2% of existing reactors, but, equally, they may suffer from 'teething problems' like earlier generations. The French experience in the late 1990s with the N4 design is particularly salutary (see Part 1, 'The current order book'). Note that in an economic analysis, the performance in the first years of operation, when teething problems are likely to emerge, will have much more weight than that of later years because of the discounting process (costs that occur in the early years weigh more heavily than those in later years, see Part 2, 'Fixed costs'). Performance may decline in the later years of operation as equipment wears out and has to be replaced, and improvements to the design are needed to bring the plant nearer current standards of safety. This decline in performance will probably not weigh very heavily in an economic analysis because of discounting. Overall, an assumption of reliability of 90% or more is hard to justify on the basis of historic experience.

Decommissioning cost and provisions

These are difficult to estimate because there is little experience with decommissioning commercial-scale plants. The cost of disposal of waste, especially intermediate or long-lived waste, which accounts for a high proportion of estimated decommissioning costs, is similarly uncertain. However, even schemes which provide a very high level of assurance that funds will be available when needed will not make a major difference to the overall economics. For example, if the owner was required to place the (discounted) sum forecast to be needed to carry out decommissioning at the start of the life of the plant, this would add only about 10% to the construction cost. The British Energy (the privatised UK nuclear power plant owner) segregated fund, which did not cover the first phase of decommissioning, required contributions of less than £20m (€30m) per year equating to a cost of only about £0.3/MWh (€0.45/MWh) (see Annex B).

The problems come if the cost has been initially underestimated, if the funds are lost or if the company collapses before the plant completes its expected lifetime. All of these problems have been suffered in Britain (see Appendix for an account of how decommissioning funds have been mismanaged in the UK). The expected decommissioning cost of the UK's first generation plants has gone up several-fold in real terms over the past couple of decades. In 1990, when the CEGB (the former nationally owned monopoly generation company that supplied England and Wales) was privatised,

the accounting provisions made from contributions by consumers were not passed on to the successor company, Nuclear Electric. The subsidy that applied from 1990-96, described by Michael Heseltine⁴⁵ as being to 'decommission old, unsafe nuclear plants' was in fact spent as cash flow by the company owning the plant and the unspent portion has now been absorbed by the UK Treasury. The collapse of British Energy has meant that a significant proportion of the decommissioning costs of the old nuclear power plants will be paid by future taxpayers.

Insurance and liability

There are two international legal instruments contributing to an international regime on nuclear liability: The International Atomic Energy Agency on Civil Liability for Nuclear Damage of 1963 and the OECD's Paris Convention on Third Party Liability in the Field of Nuclear Energy, from 1960 and the linked Brussels Supplementary Convention of 1963. These conventions are linked by the Joint Protocol, adopted in 1988. The main purposes of the conventions are to:

1. Limit liability to a certain amount and limit the period for making claims;
2. Require insurance or other surety by operators;
3. Channel liability exclusively to the operator of the nuclear installation;
4. Impose strict liability on the nuclear operator, regardless of fault, but subject to exceptions (sometimes incorrectly referred to as absolute liability); and
5. Grant exclusive jurisdiction to the courts of one country, normally the country in whose territory the incident occurs.

In 1997 a Protocol was adopted to amend the Vienna Convention, which entered into force in 2003 and in 2004 a Protocol was adopted on the Paris Conventions. These both changed the definition of nuclear damage and changed the scope. For the Brussels Convention new limits of liability were set as follows: **Operators (insured) €700m; Installation State (public funds) €500m; and Collective state contribution €300m; a total liability of €1500m. These new limits have to be ratified by all contracting parties and are currently not in force.**

Not all countries that operate nuclear facilities are party to either of the Conventions, for example non-signatories include the USA, Switzerland, Canada, China and India. Furthermore, the Conventions only act to create a minimum level of insurance and many countries require operators or state cover to exceed the covers proposed.

The table (see Table 2.1) below shows the wide range of liability limits from very low sums, for example Mexico, to much higher sums, for example, Germany.

The scale of the costs caused by, for example, the Chernobyl disaster, which may be in the order of hundreds of billions of euro, means that conventional insurance cover would probably not be available and even if it was, its cover might not be credible because a major accident would bankrupt the insurance companies.

It has been estimated that if Electricité de France (EdF), the main French electric utility, was required to fully insure its power plants

Table 2.1: Operator Liability Amounts and Financial Security Limits In OECD Countries as of October 2006⁴⁶

	Liability limits under national legislation (€m)	Financial security requirements (€m)
Belgium	328	
Finland	291	
France	83	
Germany	Unlimited	2,500
Great Britain	164	
Netherlands	311	
Spain	137	
Switzerland	Unlimited	866
Slovakia	75	
Czech Republic	188	
Hungary	109	
Canada		63
USA	10,937	300
Mexico	9	
Japan	Unlimited	538
Korea	438	

Source: Unofficial Statistics - OECD/NEA, Legal Affairs

with private insurance but using the current internationally agreed limit on liabilities of approximately €420m, **it would increase EdF's insurance premiums from €0.017/MWh, to €0.19/MWh**, thus adding around 8% to the cost of generation. However, if there was no ceiling in place and an operator had to cover the full cost of a worst-case scenario accident, it would increase the insurance premiums to **€5/MWh, thus increasing the cost of generation by around 300%**⁴⁷.

There have been proposals that 'catastrophe bonds' might provide a way for plant owners to provide credible cover against the financial cost of accidents. A catastrophe bond is a high-yield, insurance-backed bond containing a provision causing interest and/or principal payments to be delayed or lost in the event of loss due to a specified catastrophe, such as an earthquake. Whether these would provide a viable way to provide some insurance cover against nuclear accidents and what the impact on nuclear economics would be will be hard to determine until concrete proposals are made.

Variable costs

Non-fuel operations and maintenance cost

The non-fuel operations and maintenance (O&M) costs are seldom given much attention in studies of nuclear economics. As discussed below, the cost of fuel is relatively low and has been reasonably predictable. However, the assumption of low running costs was proved wrong in the late 1980s and early 1990s when a small number of US nuclear power plants were retired because the cost of operating them (not including repaying the fixed costs) was found to be greater than cost of building and operating a replacement gas-fired plant. It emerged that non-fuel O&M costs were on average in excess

of \$22/MWh (€16.5/MWh) while fuel costs were then more than \$12/MWh (€9/MWh).⁴⁸ Strenuous efforts were made to reduce non-fuel nuclear O&M costs and by the mid 1990s, average non-fuel O&M costs had fallen to about \$12.5/MWh (€9.4/MWh) and fuel costs to \$4.5/MWh (€3.40/MWh). However, it is important to note that these cost reductions were achieved mainly by improving the reliability of the plants rather than actually reducing costs. Many O&M costs are largely fixed – the cost of employing the staff and maintaining the plant – and vary little according to the level of output of the plant so the more power that is produced, the lower the O&M cost per MWh. The threat of early closure on grounds of economics has now generally been lifted in the USA because, on a marginal cost basis, the plants are low cost generators.

It is also worth noting that British Energy, which was essentially given its eight nuclear power plants when it was created in 1996, collapsed financially in 2002 because income from operation of the plants barely covered operating costs. This was in part due to high fuel costs, especially the cost of reprocessing spent fuel, an operation only carried out now in Britain and France (see below). British Energy has subsequently acknowledged that expenditure in that time was not sufficient to maintain the plants in good condition⁴⁹. Average O&M costs for British Energy's eight plants, including fuel, varied between about €24.5-28.0/MWh from 1997-2004. However, in the first six months of fiscal year 2006/07, operating costs including fuel were €35.5/MWh because of poor performance at some plants.

Fuel cost

Fuel costs have fallen as the world uranium price has been low since the mid-1970s although in recent years, the price of uranium has risen, more than doubling in 2006. These higher uranium costs have yet to be reflected in fuel costs for reactors, although given that much of the cost of fuel relates to processing, such as enrichment, the effect will be limited.

US fuel costs average about \$5.0/MWh (€3.75/MWh) but these are arguably artificially low because the US Government assumes responsibility for disposal of spent fuel in return for a flat fee of \$1/MWh (€0.75/MWh). This is an arbitrary price set more than two decades ago and is not based on actual experience – no fuel disposal facilities exist in the USA or anywhere else – and all the US spent fuel remains in temporary store pending the construction of a spent fuel repository, expected to be at Yucca Mountain.

Fuel costs are a small part of the projected cost of nuclear power. The issue of spent fuel disposal is difficult to evaluate. Reprocessing is expensive and, it does little to help waste disposal. Reprocessing merely splits the spent fuel into different parts and does not reduce the amount of radioactivity to be dealt with or the heat load. Indeed, reprocessing creates a large amount of low and intermediate level waste because all

the equipment and material used in reprocessing becomes radioactive waste. The previous contract between BNFL and British Energy, before its collapse, was reported to be worth £300m (€400m) per year, which equates to about £5/MWh (€7.5/MWh). The new contract is expected to save British Energy about £150-200m (€225-300m) per year, although this will be possible only because of underwriting of losses at BNFL by the Government. The cost of disposing of high-level waste is hard to estimate because no facilities have been built or are even under construction and any cost projections should have a very wide margin for error.

Accounting lifetime

One of the features of Generation III/III+ plants compared to their predecessors is that they are designed to have a life of about 60 years while their predecessors generally had a design life of about half that. For a technology dominated by fixed costs, it might be expected that doubling the life would significantly reduce fixed costs per unit because there would be much longer to recover these costs. In practice, this does not apply. Commercial loans must be repaid over no more than 15-20 years and in a discounted cash flow calculation, costs and benefits more than 10-15 years forward have little weight.

There is a trend to life-extend existing plants and PWRs are now often expected to run for more than 40 years, compared to their design life of around 30 years. At present, life extension in the USA appears to be an economically sound decision. However, life extension may require significant new expenditure to replace worn out equipment and to bring the plant closer to current safety standards. Life extension is not always possible and, for example, Britain's AGRs which had a design life of 25 years are now expected to run for 35 years, but life extension beyond that is not expected to be possible because of problems with the graphite moderator blocks.⁵⁰

Impact of liberalisation of electricity industries

When the electricity industry was invariably a monopoly, utilities were normally guaranteed full recovery of costs found to be used and useful as well as prudent. This made any investment a very low risk to those providing the capital because consumers were bearing most of the risk. The cost of capital varied according to the country and whether the company was publicly or privately owned. Publicly owned companies in OECD countries generally have a high credit rating and often do not have to raise equity capital (which is more expensive than debt) therefore the cost of capital is lower than for a commercial company. The range was 5-8%.

Arguably, this low cost of capital was a distortion and led to utilities building more capital-intensive options than they should have done, because they were not being exposed to the economic risk

they were taking. Building a power station of almost any type is a highly risky venture: fuel choice could prove wrong, construction costs could escalate and demand might not grow at the forecast rate. But because consumers or taxpayers usually 'picked up the tab' if things went wrong, this risk was ignored by utilities and financiers. If the risk had been borne by the utilities and if bad technology or fuel choices were directly reflected in their profits, utilities would have been much more cautious in their investment decisions, choosing low capital cost options and options that had a low risk of going seriously wrong.

In an efficient electricity generation market, the risk of investment would fall on the investors in the power plants not the consumers, for it is the investors who have the best information as well as control over the project managers. The cost of capital would reflect the risks. For example, in 2002 in Britain (by then a fully liberalised electricity market), about 40% of the generating capacity was owned by financially distressed companies (about half of this was the nuclear capacity) and several companies and banks lost billions of pounds on investments in power stations that they had made or financed. In these circumstances, a real cost of capital of up to 15% seems justified.⁵¹ If the risks were reduced, for example, by government guarantees, the cost of capital would be lower, but this would represent a government subsidy (state aid). It would distort the efficient resource allocation function of market prices by providing a resource (capital) at less than its true cost, and it is not clear if this form of 'state aid' would be acceptable under European Union law.

US experience

Competitive power supply markets came into being largely as a result of US nuclear power experience in the 1970s. As nuclear plants came on line at prices far above their cost estimates and customer bills tripled between 1970 and 1980, public outrage resulted in the passage of legislation (the 1978 Public Utilities Regulatory Policies Act) requiring US utilities to buy power from any supplier offering it at prices below the utility's own projected cost of supplying it.

Initial projections that little such power would be available proved wildly inaccurate. By the mid-1980s many utilities were using competitive power procurement auctions in which companies could bid to supply a forecast need for additional power. For example, if it was forecast that demand would grow by, say, 500MW, an open contest to supply this power would be held and the company that bid the lowest price would be awarded a contract to supply the quantity of power offered at the price it had bid. Between 1980 and 2002, the percentage of US power supplied by independent companies (i.e., not the local electric utility) rose from 2.2% to 35%.

In the US during the period when some 120 nuclear plants were built and as many again were ordered and later cancelled, most

of the risk was borne by the customers. In some cases, where regulators found 'imprudence', they required the plant owner to bear any additional costs resulting from that imprudence rather than recovering them from consumers. In addition, customers were often protected from paying for the costs of cancelled plants. Generally, however, regulators approved the substantial rate increases needed to pay for nuclear cost overruns and for many of the cancelled plants, often in the belief that rising oil prices would mean that the leading alternative sources would be equally expensive.

The development of competitive power procurement meant that winning bids contained guaranteed volumes and guaranteed prices or price formulas. This meant that the amount and price paid for electricity was predictable. However, the economic risk that the plant would cost more than the guaranteed price was transferred to the power plant developers. Builders of non-nuclear power plants were willing to take these risks, as were vendors of energy efficiency services. Consequently, nuclear power, combining uncompetitively high prices with a need to have the risks of cost overruns and poor operating records borne by the customers, had no chance in the USA or in other countries that moved to genuinely competitive power procurement.

Electricity reforms elsewhere

During the 1990s, following reforms in Chile and Great Britain, many of the vertically integrated utilities in the US were broken up into separate generation, transmission and distribution companies, a process known as restructuring. Restructuring has now largely halted in the US as a result of the California power crisis of 2000-01, leaving the country divided between areas that offer forms of retail customer choice and those that do not. However, transforming electricity generation from a monopoly to some form of market - which does not necessarily involve customer choice at the retail level - remains the rule rather than the exception, and competitive power supply procurement has spread widely in Europe and Latin America as well as sporadically in Asia and Africa.

In many cases, these reforms have been accompanied by the introduction of competitive day-to-day power markets. If these markets are effective, this will add further to the risks faced by power plant owners. In such a market, the owners will not only face the risk of having to bear additional costs if the plant does not perform to expectations, they also bear the risk because they will not know how much power they will be able to sell and at what cost.

No new nuclear unit has ever won a competitive solicitation anywhere. Indeed, a new nuclear unit has never even been bid. Two interconnected factors explain this result. First, new nuclear power plants have been more expensive than fossil fuel alternatives. Second, competitive markets put

Box 3 : The Market for CCGTs in the UK, 1990-92

To understand how these risks might be dealt with, it is useful to look back at the terms, to reduce economic risk to the buyer, imposed on purchase of the large number of combined cycle gas turbine (CCGT) plants ordered in Britain in the first years after liberalisation of the electricity industry (1990-92).

- **Construction cost:** Plants were generally supplied on a turnkey basis, i.e., at a price that was fixed for the buyer. If costs escalated, the vendor paid the extra.
- **Construction time:** Under turnkey terms, if the plants were completed late, the vendors paid compensation to the utility for the extra costs (interest on capital, replacement power purchase costs etc).
- **Reliability:** The reliability of the plants was guaranteed by the vendors or under insurance policies so that if the plant did not meet the guaranteed level of performance, the utility was compensated.
- **Back-to-back gas purchase and power sale contracts:** Gas was supplied on long-term (usually 15 year) take-or-pay contracts with limited scope for price escalation. These contracts were matched by power sale contracts, for the same duration and a corresponding quantity of energy. This ensured that the receipts for power sales more than covered costs including gas purchase. Note that in many cases, the power station owner was also the power purchaser.

There are a number of points to be made about these contracts.

- The vendors believed that they were not too risky because a CCGT is largely a factory made piece of equipment with very little site work. This means that the cost is largely under the control of the vendor;
- The vendors believed that the equipment design was mature and the risk of unexpectedly poor performance was low;
- CCGT technology is politically non-controversial and problems of safety concerns, public opposition etc were unlikely to have an impact on the operation of the plant;
- The retail market in the UK was only partly open. It was not planned to be opened for 6-8 years and there was doubt that it could be opened to residential consumers. This meant that the buyers of the power could assume that about a third of their market was captive for at least 6-8 years and possibly longer and any additional costs could be passed on to these captive consumers;
- At that time, the UK was a self-sufficient 'gas island' with no scope to trade gas internationally and this meant it was possible to price gas at terms not related to the oil price because the only feasible market for UK produced gas then was the UK.

It is worth noting that, even though these contracts were, at the time, seen as essentially risk-free, they turned out to be uniformly highly unprofitable to the plant owners, the plant vendors and to consumers. The risks that had not been anticipated were that: the price of gas would fall sharply locking the plant owners into uneconomic gas purchases; technical progress mean that by 1995, the thermal efficiency of a state-of-the-art CCGT had increased from about 50% to more than 55% making the older plants technologically obsolescent; the retail market did actually open in 1998, reducing the scope for plant owners to pass additional costs on to consumers.

From the vendors' point of view, the designs proved unexpectedly problematic and large sums of money had to be paid in compensation for poor reliability.

Captive (residential) consumers also suffered because this expensive power was allocated to them with their retailers' cheaper purchases being allocated to the more competitive (industrial consumers) market.

the financial risks of failure on investors, and investors have been unwilling to bear the risk of a nuclear plant.

In countries still building nuclear power plants, the risk that the units will cost too much or perform badly is borne by someone other than private investors.⁵² Sometimes risks are borne by the government and by taxpayers; sometimes they are borne by the electricity consumers.

Dealing with risks in competitive electricity markets

The difficulty of attracting capital to build a nuclear power plant (or any other capital intensive or technologically risky option) to operate in a competitive electricity market has long been recognised. Other technology options with lower construction costs and a lower level of technical risk, especially the combined cycle gas turbine or CCGT, are able to survive in competitive electricity markets. This is because equipment

suppliers, financiers and sometimes fuel suppliers are willing to bear some of the risk that would otherwise fall solely on the plant owner. Box 2 shows how CCGTs were financed in the British liberalised electricity market. But how feasible is it to try to apply such measures to new nuclear power plants?

Construction time

Guarantees on construction time for a nuclear plant will be highly risky. In November 2006, Nucleonics Week reported that for the Olkiluoto contract (see Part 3, 'The Olkiluoto order'):

According to industry sources, the contractual penalty for Areva is 0.2% per week of delay past the May 1, 2009 commercial operation target for the first 26 weeks, and 0.1% beyond that. The contract limits the penalty to 10% of the total contract value, or about €300m, these sources said.⁵³

If we assume the contract was signed for €3bn and the expected

delay is now 18 months, the **€300m limit will be reached after** about 17 months and any further delays will be uncompensated. By November 2006, the expected delay at Olkiluoto was indeed 17 months⁵⁴. In this context, the existing losses for Areva by end 2006 of **€700m seem likely to be an underestimate, the penalties** for late completion accounting for 60% of this figure. If the costs over-run, by, say, 20%, a modest over-run by nuclear industry standards, Areva will end up losing **€900m on this order**.

Reliability

Poor performance can be particularly costly for a utility. Take the example of a 1,000MW plant that operates at a load factor of 80% rather than 90% and the wholesale price of power is **€50/MWh**. The lost income from electricity sales alone will be **€44m per year**. The overall losses could be much higher if the poorer reliability increases operations and maintenance cost and the cost of buying the replacement power from the market is high.

One of the most impressive achievements of the nuclear industry has been the improvement in reliability of nuclear plants so that the world average load factor has increased from about 60% in 1980 to about 85% in 2005. However, this level of performance is no more than has always been forecast.

Experience with the most recent Framatome design, N4 (predecessor to EPR), shows that reliability is still not assured, especially for new, untested designs (see Part 1, 'The current order book'). Until all new plants operate from the start of service at levels of 85-90% load factor, it will be too great a risk for the nuclear vendors to offer a guarantee of performance. A particular problem for nuclear plants is that generally no one company controls the whole of the plant. For example, at the projected Flamanville plant in France (see Part 3, 'Flamanville'), Areva will supply the nuclear island, Alstom the turbine generator, Bouygues, the civil works and EDF itself the architect engineering. It is hard to see how one company would gamble on the performance of all the other contractors by offering a performance guarantee.

The problems with the ABWRs in Japan (see Part 1, 'Generation III/III+ plants') show that it is not just the nuclear island that causes problems. Here, problems with the conventional part of a nuclear plant, the turbine generator, at only two units have significantly affected Hitachi's profits and potentially its credit rating, because of the cost of repairs and replacement it will have to face as well as compensation to the plant buyer.

Power purchase agreements

If electricity markets are not a sham, long-term power purchase agreements at prices not related to the market will not be feasible unless the cost offered is very low. If the wholesale market for

power is efficient, most power will be bought and sold at spot- or spot-related prices. If retail markets are effective, consumers will switch regularly to obtain the cheapest available price. A long-term power purchase contract to buy the output of the plant at pre-determined prices will either be a huge risk, or will not be worth the paper it is printed on. If retail markets are well-used, no retailer will know from one year to the next what their market will be and the risk of company failure will be significant.

The circumstances of the Olkiluoto contract are very particular (see Part 3, 'The Olkiluoto order'). The buyer, TVO, is a not for profit consortium of electric intensive industries that have contracted for the output of the plant at cost-related prices, over its whole life. Such a consortium probably is a credible buyer, but if the operating costs of the plant are higher than forecast, or the price of power in the NordPool, the wholesale market covering the four Nordic countries, is lower than forecast, the competitiveness of these companies (for which electricity may account for up to 50% of their costs) will be heavily impaired. It is hard to see how or why it would be possible for electric-intensive industry to form consortia in other countries, effectively gambling the competitiveness of their companies on the ability of the nuclear industry to control cost and achieve high reliability.

While the moves towards liberalisation are now experiencing difficulties and may be halted in some places, it seems unlikely that even where generation remains a regulated monopoly that regulators will allow generators to pass on imprudently incurred costs to consumers. If the terms of a power purchase agreement are fixed, this will be a big risk to the generator, who will have to absorb additional costs if things go wrong. If the terms are more flexible, the buyer will take the risk that they will not be allowed to recover their costs from consumers.

Long-term liabilities

From an economic appraisal perspective, long-term liabilities such as waste disposal and decommissioning should have little impact on the economics of nuclear power. At the start of the life of the plant, decommissioning will be 60 or more years away and final disposal of spent fuel will also be many decades away. In the type of discounted cash flow calculation used in project appraisal, costs and income are 'discounted' to a 'net present value'. In other words, if there is a cost of, say, **€100m in 10 years'** time, and it was assumed the discount rate was 5%, the discounted value of this cost would be **€61.3m**. **The rationale is that a sum of €61.3m was invested today at a real (net of inflation) interest rate of 5%, after 10 years, it would have grown to €100m.** By the same logic, income of **€100m earned in 10 years would be worth only €61.3m today**.

While this has an intuitive logic, over longer periods and at higher discount rates, the effect is alarming and seems to trivialise huge long-term liabilities. For example, if it was assumed that

decommissioning would cost **€1bn and the discount rate** was 15% (reflecting the high risk of investing in nuclear power stations), a sum of only **€3m would grow sufficiently at this rate to produce a sum of €1bn in 60 years.**

The fault in the logic is that if the 'polluter is going to pay' the assumption that a real interest rate of 15% will be available for 60 years is untenable. The discount rate applied to construction costs is a 'rationing' device to ensure that limited funds are channelled to the most profitable use. The discount rate applied to decommissioning funds is a minimum expected rate of return on investment chosen to reduce the risk that funds will not be available.

To provide assurance that funds will not be lost, they are, in most countries, invested in very low risk investments paying correspondingly low interest rates, perhaps 2-3%. At a discount rate of 2%, **€1bn discounted over 60 years falls to €300m.**

If, as seems likely to be the case, countries move towards systems of providing funds for long term liabilities that minimise the risk of a funding shortfall, for example, by requiring the plant owner to deposit the full discounted liability for decommissioning on the day the plant starts, this will make a noticeable difference to the initial cost. For example, if it was assumed that Olkiluoto would cost **€1bn to decommission, the €3bn capital cost would increase by 10%.**

However, costs of decommissioning have been escalating rapidly and, for example, the expected cost of decommissioning Britain's first generation plants has increased by a factor of 6 in the past 15 years (see Appendix). This represents a major risk to plant owners.

For example, if it is assumed decommissioning will cost **€1bn** and will take place 60 years after the plant starts up, at a discount rate of 2%, the company will be required to deposit **€300m at the start of operation. However, if it is discovered that, after 30 years, the plant will only operate for 40 years and the decommissioning cost is €2bn, the utility will have to find another €1.2bn, likely to be enough to bankrupt many utilities.** On past experience, such shocks would be by no means unusual. Insurance companies would be unlikely to be prepared to insure against such a risk (or would require a huge premium) and plant owners would probably look to government to offer guarantees to prevent the exposure to risks from waste disposal and decommissioning liabilities.

Recent studies on nuclear costs and why they differ

One of the elements driving the debate on nuclear power has been the publication since 2000 of a number of forecasts of nuclear generation costs from apparently authoritative and often

independent sources, that appear to show that nuclear power is, at worst, competitive with other generation sources, and, at best, a cheap generation source. These include:

1. May 2000 'The Role of Nuclear Power in Enhancing Japan's Energy Security' James A Baker III, Institute for Public Policy of Rice University⁵⁵;
2. 2002: Lappeenranta University of Technology (LUT). 'Finnish 5th Reactor Economic Analysis'⁵⁶;
3. February 2002: 'The economics of nuclear power' UK Performance and Innovation Unit⁵⁷;
4. September 2002: 'Business Case for Early Orders of New Nuclear Reactors', Scully Capital⁵⁸;
5. February 2003: 'The Future of Nuclear Power: An Interdisciplinary MIT Study'⁵⁹;
6. March 2004: 'The Costs of Generating Electricity' The Royal Academy of Engineering⁶⁰;
7. March 2006: 'Powering the nation: A review of electricity generating costs' PB Power⁶¹;
8. August 2004: 'The economic future of nuclear power' University of Chicago, funded by the US Department of Energy⁶²;
9. August 2004: 'Levelised Unit Electricity Cost Comparison of Alternative Technologies for Base load Generation in Ontario' Canadian Energy Research Institute: Prepared for the Canadian Nuclear Association⁶³;
10. March 2005: 'Projected Costs of Generating Electricity: 2005 update' IEA/NEA⁶⁴; and
11. April 2005: 'Financing the nuclear option: Modelling the costs of new build' OXERA⁶⁵.
12. July 2006: 'Nuclear Power Generation Cost Benefit Analysis', UK Department of Trade and Industry⁶⁶.

However, a forecast is only as good as the assumptions that go into it and it is necessary to examine these assumptions to see what weight should be placed on these forecasts. The section on nuclear economics identifies the key assumptions for economic appraisals of nuclear power. The most important assumptions are the ones that determine the fixed cost per kWh, construction cost, cost of capital and reliability. However, operating costs, particularly non-fuel operations and maintenance (O&M) should not be ignored. Table 2.2 tabulates the key assumptions made in each of these studies.

Rice University

The Rice University study examines strategic issues for Japan in ensuring its energy security. It uses a forecast of the overall cost of generation from plants coming on line in 2010 produced by the Japanese Central Research Institute of Electric Power Industry (CRIEPI).⁶⁷ This produces a cost per kWh of **€75/MWh. However,** this figure should be seen in the context of the very high price of electricity in Japan, partly attributable to the high value of the Yen, and without examining CRIEPI's assumptions in detail it is difficult to draw strong conclusions.

Lappeenranta University of Technology

The Lappeenranta study was widely publicised when the decision to go ahead with Olkiluoto was taken. Many of the assumptions are not fully specified, being classified as commercially sensitive, but the very low cost of capital, the low operating costs and the high load factor inevitably lead to a low generation cost. The Olkiluoto order is discussed in Part 3.

Performance and Innovation Unit

The Performance and Innovation Unit (PIU) of the UK Cabinet Office reviewed the economics of nuclear power in 2002 as part of the Government's review of energy policy leading to the White Paper of 2003. It estimates the cost of generation from Sizewell B, if first-of-a-kind costs are excluded, which is estimated to reduce the construction cost of Sizewell B to £2250/kW (total cost of **€4bn**) as about **£60/MWh (€90/MWh)** if a 12% discount rate is applied.

It also reports the forecasts provided by British Energy and BNFL and presents them using common assumptions on the discount rate. It is difficult to represent all the information in the PIU report. The table shows the costs for the 8th unit, built as twin units and using AP1000 technology. The assumption is that by the 8th unit, all set-up and first-of-a-kind charges will have been met and the 'settled-down' cost will apply. It uses BNFL's assumptions but with PIU's assumptions of discount rates of 8%, to represent a plant built where there was very low risk, for example if there was full cost pass-through to consumers, and 15%, to represent a plant subject to much greater commercial risk. The 8% case is calculated with a 15 year plant life (to represent the likely length of a commercial loan) and a 30 year plant life, while the 15% case is only shown with a 15 year life. Given that a cost or benefit arising in 20 years counts as only 6% of its undiscounted value and one arising in 30 years counts as only 1.5% of its undiscounted value in a DCF calculation, the difference between a 15 and 30 year life is likely to be small. The cost estimates if only one unit is built are 40-50% higher reflecting the assumption that first-of-a-kind costs will be about £300m (**€440m**).

Many of the assumptions, such as for construction cost, are categorised as commercially sensitive and are not published. However, the PIU does state that BNFL's and British Energy's construction cost estimates are less than £840/kW (**€1260/kW**). On load factor, the figures are also confidential although the PIU states the assumed performance is significantly higher than 80%.

Scully Capital

The Scully report was commissioned by the US of Department of Energy and examines the costs of generation from a 1100MW PWR (AP1000) under four assumptions of construction cost, \$1bn, \$1.2bn, \$1.4bn and \$1.6bn, equivalent to €750/kW,

€900/kW, €1050/kW and €1200/kW. Unlike other reports, the Scully approach is to forecast the wholesale electricity price and see what rates of return a nuclear plant would yield under their performance assumptions. At a market electricity price of \$35/mWh (**€26/MWh**), a nuclear plant would achieve an internal rate of return including inflation of 7.3-10.7%, depending on the construction cost. It compares this to the industry norm of 10-12%. Only the \$1bn (**€0.75bn**) construction cost case is within this range. Sensitivity analyses are carried out on the market price for electricity, the load factor, the price of fuel and the construction time. There are also sensitivities on the financial aspects including the proportion of debt to equity and the cost of borrowing.

MIT

The 2003 MIT study was a very detailed and prestigious study of nuclear generation costs compared to fossil fuel generation options such as CCGT plants. Energy efficiency and renewable energy were not considered. It has detailed assumptions on the important elements. On O&M costs, it assumes that these can be 25% less than the average for existing plants because of competitive pressures on generators. On construction costs, the report acknowledges that its assumed costs are far lower than those incurred in the most recent plants in the USA (albeit these were completed about 20 years ago). On capacity factor, the report considers two cases with 85% as the upper case and 75% as the lower case. It bases these assumptions on the good recent performance of US plants for the upper case, but the many years it took to achieve this level for the lower case. The assumptions on decommissioning are not specified but it can be assumed they follow current practice mandated in the USA of requiring a segregated fund. The assumed cost of decommissioning is not specified.

The main sensitivities reported are on load factor and on project lifetime, although reflecting the relatively high cost of capital, the lifetime extension makes only a small difference to the overall cost (about 5%), while the load factor assumption change makes a much greater difference (about 10-15%). In all cases, the gas and coal-fired options are substantially cheaper than nuclear, up to 45% for gas and about 35% for coal. Even reducing nuclear construction costs by 25%, construction time by 12 months and the cost of capital to 10% does not close the gap between nuclear and coal or gas.

The Royal Academy of Engineering

The Royal Academy of Engineering report compared a range of generating technologies and found that the cost of power from a nuclear plant was very close to the cost of power from a gas-fired plant, about 10-30% cheaper than coal (depending on the coal technology used) and about a third of the cost of renewables. It assumed there were three possible reactor choices, the EPR, AP1000 and the ACR. It drew heavily on the MIT for its estimates of the cost determinants, although it did

not follow them in all cases, citing 'engineering judgement' where it differed. For example, on O&M costs, it forecast costs nearly 50% lower than MIT.⁶⁸ The report states that an allowance for decommissioning cost is included in the capital cost, but it does not specify the cost assumptions. Its assumptions seem consistently optimistic for all parameters and the overall low cost of generation is therefore not surprising.

PB Power

PB Power, the main contractors for the RAE study, produced an update of their report in 2006. It used a higher rate of return, but a lower construction cost and yielded much the same result as the RAE study.

University of Chicago

The University of Chicago study reviews a range of estimates of nuclear costs, but does not produce its own cost estimates. In its 'no-policy' scenario, it calculates the levelised cost of electricity (LCOE) for three different cases of plants of 1000MW, the most expensive representing the EPR ordered for Olkiluoto, the middle case representing a plant on which first-of-a-kind (FOAK) costs would be incurred (e.g., the AP1000) and the lowest, one on which the FOAK costs had already been met (e.g., the ABWR or ACR-700). The results shown in the table do not adequately summarise the results of the study, which presents a wide range of sensitivities, but they do illustrate that even with extremely low construction costs, a relatively high discount rate does have a severe impact on overall costs.

Canadian Energy Research Institute

The Canadian Energy Research Institute study compares the forecast costs of generation from coal and gas-fired generation with the cost of generation from a pair of Candu-6 units (1346MW total), the current generation of Candu, and a pair of ACR-700 units (1406MW total), the Generation III Candu design.⁶⁹ We focus on the ACR-700 option, which is forecast to be cheaper than the Candu-6. Decommissioning costs are assumed to be about £250/kW (€375/kW) and payments are made into a fund through the life of the plant, amounting to £3.6m (€4.9m) per year over 30 years or 0.03p/kWh (€4.5/MWh). The overall cost is relatively low and most of the assumptions are similar to those used in other studies.

International Energy Agency/ Nuclear Energy Agency

The IEA/NEA study is based on questionnaire responses from national authorities on the cost of generation options. It is difficult to evaluate this report because of the huge range of national assumptions, with Eastern European countries often providing very low costs and Japan very high. The key factor is the very low discount rate used, which with relatively optimistic performance assumptions gives low generation costs.

OXERA

Consultancy group OXERA's report of April 2005 was followed by a second report in June giving more details on the assumptions behind the cost estimates.⁷⁰ The OXERA report includes very detailed financial analysis of the economics but it relies mainly on other reports for its assumptions on technical

performance. For example, a very high assumption on load factor of 95% is included with no justification. The OXERA report follows the same approach as the Scully report of calculating the rate of return that would be achieved at a given electricity price. With a base-load electricity price of £27-33/MWh (€40-49), about the rate British Energy received in 2006, the internal rate of return would be 8-11% for a single reactor (depending on the proportions of debt and equity). For a programme of 8 units, the return would be more than 15% for the last units. It should be noted that while the construction costs are higher than some forecasts, they are much lower than for Sizewell and lower than the reported cost of Olkiluoto. Its assumptions on load factor and operating cost, drawn partly from the IEA/NEA report and the Scully Capital report, require a huge improvement on the current generation of plants.

On the basis of these cost projections and on the cost of the Government's current programme on renewables, which OXERA estimates to be £12bn (€18bn), OXERA estimates that a nuclear programme would achieve a similar impact in terms of carbon dioxide emissions reductions at a cost of only £4.4bn (€6.6bn) plus the cost of public insurance risk. The £4.4bn (€6.6bn) is made up of £1.1bn (€1.65bn) in capital grants and £3.3bn (€5bn) in loans guarantees. OXERA does not estimate the cost of public insurance risk.

UK Energy Review 2006

This is reviewed in detail in Part 3. While many of the assumptions are essentially the same as in the previous government review carried out by the Performance and Innovation Unit (PIU), the placing of the Olkiluoto order at a cost of about €3bn meant that the PIU's very low assumption on construction cost was not credible. As noted in Part 3, 'The UK', the Central case assumes only four plants are built, while the figure assumed by the PIU is only achieved after eight units have been built.

The Review used a figure of the Olkiluoto price plus 20%. In practice, adjustments (of a dubious nature) to take account of the fact that the reported Olkiluoto cost includes interest during construction reduced the figure to a similar level to the Olkiluoto cost, but more than 50% higher than PIU used. However, the Energy Review assumed a cost of capital of only 10%, a third less than the most realistic rate (a rate for a free market decision) assumed by PIU. The net result was that the two changes approximately cancelled each other out producing about the same generation cost.

To put this result in perspective, the PIU report shows that using BNFL's figures, increasing the cost of capital from 8% to 15% increases generation cost by about 50%. As a first approximation, we can assume increasing the cost of capital from 10% to 15% would increase generation cost by about 40%. So it seems that if the Energy Review had used a more realistic cost of capital, the generation cost would have been about €80/MWh (£53/MWh).

Table 2.2
Comparison of assumptions in recent forecasts of generation costs from nuclear power plants

Forecast	Construction cost (€/kW)	Construction time (months)	Cost of capital (% real)	Load factor (%)	Non-fuel O&M €/MWh	Fuel cost (€/MWh)	Operating life (years)	Decommissioning scheme	Generating cost (€/MWh)
Rice University									50.0
Lappeenranta Univ	1,875		5	91	13	5	60		24
Performance and Innovation Unit	<1,200	-	8	>80			30		35
			8				15		42
			15				15		57
Scully Capital	725-1,160	60		90	8	4	40	€390m accrued in 40 year life of plant	
Massachusetts Institute of Technology	1,600	60	11.5	85	11(1)	-	40		67
				75			25		79
Royal Academy of Engineers	1,660	60	7.5	90	12	10	40	Included in construction cost	41
Royal Academy of Engineers (update)	1,520	60	10	90	13	10	40		41
Chicago University	800-1,450	84	12.5	85	8	4	40	€290m	43-58
Canadian Nuclear Assoc.	1,550	72	10	90	7	4	30	Fund. €0.45/kWh	50
IEA/NEA	1,600-3,600	60-120	5	85	10-24	4-17	40	Included in construction cost	18-40
OXERA	2,350 first plant 1,670 later unit		10	95	9	1	40	€750m in fund after 40 years life	36-76
UK Energy Review 2006	1,875	72	10	80-85	11.5	5.8	40	€600/kW	57

Notes:

1. The MIT O&M cost includes fuel.

Long-term forecasting

The large construction costs and long operating times make nuclear power uniquely vulnerable to changes in markets. UBS Investment Research undertook an assessment of the European market for equity investors which concluded that 'endorsing new nuclear is... a potentially courageous 60-year bet on fuel prices, discount rates and promised efficiency gains...'.⁷¹ Other economic forecasters agree with the importance of these parameters and would include the price of carbon as an additional important factor.

Fuel prices

In the time of the oil shocks in the 1970s and 1980s the world was much more dependent on oil than is currently the case. This is partly the reason why the oil price increase from 1998-2005, where the price of oil has increased five fold, has not had the same economic impact as a similar price spike had during the 1970s. In the 1970s and 1980s oil had a much wider application and was, for example, used to generate electricity, which is much less the case today.

However, there is still a close price correlation between the price of oil and the price of electricity as the prices of oil is linked to that of natural gas, and to a lesser extent that of coal. As natural gas is increasingly used in the production of electricity, oil and electricity price movements have a causal linkage.

The period of higher oil prices from the mid 1970s to mid 1980s was also one of optimism for the nuclear industry, with orders still being made in the United States (before Three Mile Island) and in Europe before the orders tailed off following Chernobyl.

The European Commission has undertaken analysis on the impact of higher oil and gas prices on the use of different energy technologies. In their base case scenario the price of oil in 2030 in 2005 dollars is \$63/barrel, but under a high price scenario it reaches \$99/barrel. In the high oil and gas price scenario the use of nuclear increases, but only by 6.5%, compared to the increased use of renewables of 12.5%.⁷²

The future price of oil is uncertain, with significantly differing views. The International Energy Agency's World Energy Outlook for 2006 estimates in its base-case scenario that the price of oil in 2030 will be – in 2005 dollars – \$55/barrel.

Interest rates

The large construction costs of nuclear power make it susceptible to changes in interest rates and in fact more susceptible than other energy sources that have lower construction costs and times. The amount of interest that a utility has to pay for borrowing the necessary finance to construct a nuclear power plant impacts significantly upon expected costs of the electricity produced. In economic models the effect of changing interest rates is defined as the

discount rate (which is the sum of the initial investment plus the interest accumulated divided by the length of time the loan is taken out for). This has a significant impact on the economics of nuclear electricity. Based on the economic data put forward by the Nuclear Energy Agency, it is possible to see that increasing the discount rate from 5% to 10% in the economic models increases by 50% the cost of nuclear electricity.⁷³

Carbon pricing

The recognition of the environmental and economic consequences of climate change has increased the pressure to reduce CO₂ emissions. Through the Kyoto Protocol many countries have agreed to put a limit on their CO₂ emissions. However, the Protocol effectively excludes nuclear energy as an operation from its flexible mechanisms that Annex I parties to the Convention can use to meet their reductions targets. Specifically, nuclear power is excluded from the Clean Development Mechanisms (CDM, Article 12) and projects implemented jointly (Article 6). Nuclear power was not directly excluded from emissions trading schemes.⁷⁴

In order to meet this target signatories have had to put in place mechanisms to reduce emissions in particularly from the power sector. In Europe this has resulted in the introduction of an Emissions Trading System which puts a ceiling on the amount of CO₂ fixed sources can emit and has resulted in the establishment of a carbon market, as CO₂ producers trade their emissions permits.

Over the last two years, since the establishment of the European carbon market, the price has fluctuated in the range of **€2-30/tonne carbon, due to changes in energy prices, actual or anticipated availability of emissions permits and market speculations.**

Nuclear power does not receive emissions permits within the framework of the European Emissions Trading Scheme (unlike existing fossil fuel electricity generators) as it does not produce CO₂ during electricity generation. However, despite the fact that during the first round of the ETS there was considerable over-allocation of emissions permits and these were largely given for free to the electricity utilities, the establishment of the scheme has resulted in the general increase in electricity prices⁷⁵. As a result it has been said that the main economic winners of the current scheme have been the coal and nuclear utilities⁷⁶.

Many see the introduction of a long term carbon price as an important future issue for the nuclear industry and absolutely necessary for the construction of nuclear reactors. The chief executive of EDF has stated 'To make a commitment of billions of pounds to a project with a time-scale of half a century, investors above all need predictability about price. They must know the value society will place on carbon reduction not just tomorrow, but 10, 20, 30, 40 years from now.'⁷⁷ This would require a significant change in the current emissions trading schemes.

Not only does there need to be a long term guarantee for the

Part 3:

A nuclear revival?

price of carbon, but, according to some, also a price which is significantly above the current market price. The MIT study calculated that 'With carbon taxes in the \$50/tC range, nuclear is not economical under the base case assumptions'. The study went on to assess that nuclear will only break even under its base case assumptions, when carbon prices are in excess of \$100/tC⁷⁸ (€71/tC).

Finland: the Olkiluoto order

The Olkiluoto order is currently the only live new order in Western Europe or North America and the first to be placed since the Civaux 2 order in France placed in 1993 and coupled to the grid in 1999.

Olkiluoto is often portrayed as the exemplar of the capabilities of current designs. It is predicted to be cheaper to build and operate, and safer. It is also seen as a demonstration that nuclear power orders are feasible in liberalised electricity markets. Many commentators claimed that nuclear power orders were unfeasible in liberalised markets because consumers would no longer bear the full risk of building and operating new power plants (see Part 2, 'Dealing with the risks of competitive electricity markets'). It is therefore important to examine the circumstances of the Olkiluoto order. To understand the Olkiluoto order, it is necessary to look at four aspects:

- Finland's background in nuclear power;
- The commercial arrangements for the order;
- The buyer; and
- Experience to date.

Finland's background in nuclear power

Finland ordered four relatively small nuclear power plants from 1971-75. Two of these at Loviisa (both 440MW net) used the first generation Russian design (VVER-440) but were upgraded to Western standards with the assistance of Siemens. The two at Olkiluoto (both 660MW net) use a Swedish BWR design similar to some plants built in Sweden. The reliability of all four plants has always been high and even today, when reliability is much higher in the rest of the world than it was in the 1980s; all four units are in the top 20% in the league table of nuclear power plants ordered by lifetime load factor. Their load factors have been better than for similar plants built in other countries. In addition, the output of the plants has been significantly upgraded, with the Loviisa units now able to produce 11% more than their original design rating and the Olkiluoto plants 30% more. So the image of Finland as a nuclear operator is relatively good and Finland is probably likely to be more receptive to new nuclear orders than countries with worse experiences.

Work on the EPR design (1,600MW) started in 1991 and by the

late 1990s, pressure on EdF to order the plant and to maintain the nuclear capability was mounting. The EPR design has been said by its supplier, the Framatome division of Areva⁷⁹, to be ready to order for nearly a decade and regulatory approval for the design by both the German and French safety authorities was granted in 2000. Areva has been increasingly concerned that, with orders in France continually delayed, regulatory approval would lapse if an order was not placed and the design proven in practice. In 1993 the Finnish Parliament rejected a proposal to build a fifth reactor. However, this was not the end of the debate and the issue was retabled. In May 2002, the Finnish Parliament finally agreed, by 107 to 92, that a fifth order could be placed and a call for tender was issued in September of that year. The main bidders and the model bid were:

- Areva, EPR (an evolutionary PWR);
- Areva, SWR (a passive safety version of the Siemens BWR)
- Atomstroyexport WWER91/99 (a modernised version of the 1000MW Russian PWR design); and
- GE, ESBWR (a passive safety BWR).

Westinghouse did not place a bid.

In December 2003, TVO, the Finnish company buying the plant announced it had selected the Areva EPR bid and a contract was placed with Framatome for supply of the nuclear island and with Siemens for the turbine generator. In March 2005, the Finnish safety authorities issued a construction license and construction began in August 2005.

The commercial arrangements for the order

To reduce the risk to the buyer, Areva offered the plant under turnkey terms. **Modern Power Systems** reported:⁸⁰

It is a fixed price contract, with the consortium having total responsibility for plant equipment and buildings, construction of the entire plant up to and including commissioning (excluding excavation), licensability, schedule and performance. The overall project cost has been estimated by TVO at around €3bn.

The turnkey terms fixed the price TVO would have to pay and allowed for fines to be levied on the contractors if the plant was late. The schedule allowed for a 48 month period from pouring of first concrete to first criticality.

Some care must be taken in comparing the reported Olkiluoto contract price with other plants because the reported cost includes two reactor cores and covers interest during construction (IDC). Conventionally, for the purposes of comparing costs, the quoted cost does not include IDC and includes the cost of the first fuel core⁸¹. So to make fair

comparisons with other cost estimates, the cost of one of the cores and the IDC should be subtracted. Given the low rate of interest on most of the finance (2.6%), IDC will be relatively small (of the order €150m), while the cost of the additional core is difficult to estimate but may be of the same order of magnitude.

The details of how the plant would be financed have not been published, but the European Renewable Energies Federation (EREF) and Greenpeace separately made complaints to the European Commission in December 2004 that they contravened European State aid regulations. According to EREF, the Bayerische Landesbank (owned by the state of Bavaria) led the syndicate (with Handelsbanken, Nordea, BNP Paribas and J P Morgan) that provided the majority of the finance. It provided a loan of €1.95bn, about 60% of the total cost at an interest rate of 2.6%. It is not clear if this is a real or a nominal rate. If it is a nominal rate, the real rate is effectively zero. Two export credit institutions are also involved: France's Coface, with a €610m export credit guarantee covering Areva supplies, and the Swedish Export Agency SEK for €110m.

In October 2006, the European Commission finally announced it would be investigating the role of Coface. It is not clear whether the Bayerische Landesbank loan and the SEK guarantee would be investigated, nor is it clear what the consequences would be if the investigation was to find against Coface.

Regardless of the result of the Commission investigation, it is clear that the arrangements for Olkiluoto are unlikely to be reproducible. The loan from the syndicate if the rate reported is accurate is far below the levels that would be expected to apply for such an economically risky investment. The role of the export credit agencies (ECAs) is also surprising. ECAs are normally involved in financially and politically risky countries in the developing world, hardly a category that Finland would fit into.

The buyer

The buyer Teollisuuden Voima Oy (TVO) is an organisation unique to Finland. For the Olkiluoto 3 unit, the largest shareholder, PVO, holds 60% of TVO's shares. PVO is a not-for-profit company owned by Finnish electric-intensive industry that generated about 16% of Finland's electricity in 2005⁸². Its shareholders are entitled to purchase electricity at cost in proportion to the size of their equity stakes. In return, they are obliged to pay fixed costs according to the percentage of their stakes and variable costs in proportion to the volume of electricity they consume. The other main shareholder in TVO is the largest Finnish electricity company, Fortum, with 25% of the shares. The majority of shares in Fortum are owned by the Finnish Government. This arrangement is effectively a life-of-plant contract for the output of Olkiluoto 3 at prices set to fully cover costs.

Experience to date

In August 2005, first concrete was poured, but almost immediately things began to go wrong. Issues about the strength and porosity of the concrete delayed work in September 2005.⁸³ By February 2006, work was reported to be at least 6 months behind schedule, partly due to the concrete problems and partly to 'problems with qualifying pressure vessel welds and delays in detailed engineering design'⁸⁴.

In February 2006, STUK, the Finnish safety regulator launched an investigation into these delays⁸⁵. By April 2006, TVO's project manager for the plant, Martin Landtman acknowledged the delays were now 9 months.⁸⁶ The plant suppliers appeared partly to blame lack of local skills⁸⁷ and instability in the Finnish regulatory environment⁸⁸ for the delays.

In March 2006, it emerged that EdF expected the second EPR order, for its Flamanville site, to cost 10% more than the contracted Olkiluoto price (€3.3bn) and that the lead-time would be 54 months instead of the 48 month period forecast for Olkiluoto.⁸⁹

In July 2006, TVO admitted the delay was now about a year⁹⁰ and the STUK report into the delays was published⁹¹. The report revealed a range of problems, 'It has been very difficult to find the root cause, because there are so many interconnected factors.'

The head of the investigation team, Seija Suksi said:

*...the time and amount of work needed for the detailed design of the unit was clearly underestimated when the overall schedule was agreed on', Areva 'is not so experienced in construction work. First of all, they didn't understand that the base slab is also safety-related construction and they didn't have enough experience to give advice to the subcontractors. The tight cost frame is also a problem in selecting and supervising subcontractors. They have very often chosen a subcontractor who has given the lowest tender.', 'we had the impression that Framatome tried to show that the concrete problems were all caused by the subcontractor, but the root causes are much deeper in the overall management of this project.' STUK wants TVO 'to communicate more clearly to the personnel on this project that turnkey delivery doesn't mean that they can stand apart from the project. TVO should remember that they are responsible for the safety of the power plant. That responsibility cannot be transferred to the supplier.'*⁹²

In September 2006, the impact of the problems on Areva started to emerge. In its results for the first six months of 2006, Areva attributed a €300m fall in operating income of its nuclear operations to a provision to cover past and anticipated costs at Olkiluoto.⁹³ The scale of penalties for late completion was also made public. The contractual penalty for Areva is 0.2% of the total contract value per week of delay

past the May 1, 2009 commercial operation target for the first 26 weeks, and 0.1% beyond that. The contract limits the penalty to 10%, about **€300m**.

More technical problems emerged in October⁹⁴ and Areva announced it was replacing the head of project.⁹⁵ Further unconfirmed reports suggested that Olkiluoto was then 2-3 years behind schedule (La Tribune November 10) and Capital, citing nuclear industry sources, reported on 20 October that 'Areva could lose over **€1bn in Finland**' because it had 'botched' the negotiation of the Olkiluoto contract.

In December 2006, Areva announced the reactor was 18 months behind schedule⁹⁶ and the French newspaper, Les Echos, reported that Areva would take a **€500m charge on the Olkiluoto contract in 2006**⁹⁷. In December, Le Monde reported that the French Ministry of Finance had said that the losses had reached **€700m**.⁹⁸

By January 2007, relations between Areva and TVO were seriously strained. In a report on Finnish television Philippe Knoche, Areva representative for Olkiluoto 3 said: 'TVO and we have had problems, for which we were not prepared for beforehand. We were not properly ready for the fact that this is a new kind of reactor and that it has to be adjusted to the Finnish conditions.' The turnkey deal appeared to be unraveling and Knoche stated: 'Areva-Siemens cannot accept 100 % compensation responsibility, because the project is one of vast co-operation. The building site is joint so we absolutely deny 100 % compensation principle.'

TVO did not accept this interpretation and Martin Landtman, when asked about Knoche's statement said: 'I don't believe that Areva says this. The site is in the contractor's hands at the moment. Of course, in the end, TVO is responsible of what happens at the site. But the realisation of the project is Areva's responsibility.'⁹⁹

Lessons

Whilst there were suspicions amongst sceptics that the Olkiluoto plant would be problematic, the scale and immediacy of the problems have taken even the sceptics by surprise. It remains to be seen how far these problems can be recovered, what the final delay will be, how far these problems will be reflected in higher costs and how these additional costs will be distributed between Areva and TVO). However, a number of lessons do emerge:

- The contract value of **€2000/kW now appears likely to be a gross underestimate** and any forecasts of nuclear costs should probably be based on a figure higher than that forecast by EdF, **€2200/kW, which may yet turn out to be an underestimate;**
- Turnkey contracts represent a huge risk for plant vendors and

the experience at Olkiluoto may well mean that vendors will see contracts that offer such a high degree of price assurance as Olkiluoto are unjustifiable;

- The skills needed to successfully build a nuclear plant to the standards required are considerable and lack of recent experience of nuclear construction projects may mean this requirement is even more difficult to meet;
- There are serious challenges to a regulatory body. The Finnish regulator had not assessed a new reactor order for more than 30 years and had no experience of dealing with a 'first-of-a-kind' design.

France: Flamanville

The French nuclear industry has been lobbying government and Electricité de France (EdF)¹⁰⁰ for nearly a decade to place an order for an EPR. After a long process, the Flamanville site was selected and is expected to receive the French equivalent of a construction permit (Decret d'Autorisation de Creation, or DAC) in 2007. Work on site was started in October 2006, but the main orders for the plant will not be placed before second part of 2007 with first concrete expected to be poured in December 2007.¹⁰¹ The plant is scheduled to take 54 months to build with first power in mid-2012, 6 months longer than Olkiluoto's original schedule.

EdF expects the plant to cost **€3.3bn, 10% more than the contracted cost** for Olkiluoto. However, unlike the OL3 contract, this cost does not include the cost of the first fuel load (conventionally included in the cost of a nuclear plant).¹⁰² Electricité de France is carrying out its own architect engineering and is procuring major items, like the turbine (Alstom), the nuclear island (Areva) and the civil works (Bouygues) separately.

Whether EdF will be able to keep to the costs it forecasts remains to be seen, but the fact that the most experienced nuclear utility in the world expects the EPR to cost more than 10% more than an inexperienced utility like TVO does suggest that the Olkiluoto contract price is totally unrealistic.

Nevertheless, EdF does expect subsequent units to be significantly cheaper than Flamanville, although it has not said by how much. It is worth noting that from 1974 to 1984, when EdF completed more than 30 nuclear units, the real cost of the plants actually increased by 54%¹⁰³. Whether EdF will choose the EPR has not been determined. Bernard Dupraz, the EdF's senior executive vice president for generation, said in May 2005 that EdF will need to begin replacing its existing reactors around 2015-2020, which means it will have to choose a strategy after the initial operation of Flamanville-3. Dupraz said the utility will take a close look at what models are available on the world nuclear plant market at that time. 'We will see if there are other

efficient models with a price differential' compared to EPR that would make them more attractive to EdF, he said.¹⁰⁴

The UK

In May 2006, pre-empting the publication of the UK Government's Energy Policy Review¹⁰⁵ in July 2006, Tony Blair said 'Nuclear power is back on the agenda with a vengeance'¹⁰⁶. His chief scientific adviser and other government spokespeople suggested that up to 20 new nuclear units would be needed. This was taken by many, internationally, as a signal that the UK was about to launch an aggressive new programme of nuclear power stations.

Is this really what will happen? And on what assumptions is Blair making the forecast that nuclear power should be 'back with a vengeance'? The detail of what is being proposed and the assumptions are to be found in the Energy Review itself and in the supporting documentation, especially a cost benefit analysis for nuclear power.¹⁰⁷

Scale of programme, government support and benefits

Scale

What is perhaps most striking is that the scale of the programme is modest. The Cost Benefit Analysis (CBA) case states:

Should the private sector take commercial decisions to invest in new nuclear, the economic analysis suggests that there is scope for adding a relatively small amount of new nuclear capacity in the period to 2025 (p 1).

It is likely that the first new nuclear plant could be added by around 2021, if not before, assuming an eight year pre-development period (for pre licensing, public enquiry, licensing, etc) starting in 2007, and six years construction (p 1).

The analysis identifies scope for replacing existing capacity by adding 6 GW of new nuclear capacity by 2025 in the base case (p 2).

This is a rather modest target requiring only that about four plants (depending on their size) be built with the first order not placed for nine years, a period during which two or possibly three general elections will take place. So there is ample scope for the programme to fail before it has even started. A programme of four orders would fall far short of the level of ordering estimated by the PIU to be necessary to achieve a 'settled down' cost. Note also that the PIU assumed that it was necessary to build plants in pairs to achieve optimal costs and unless it was possible to build the 4 units as pairs of units on just two sites, the costs would also be higher than the optimal level.

Government support

The scale of government support offered is also extremely limited. The Review stated:

Any new nuclear power stations would be proposed, developed, constructed and operated by the private sector, who would also meet full decommissioning costs and their full share of long-term waste management costs. The Government does not take a view on the future relative costs of different generating technologies. It is for the private sector to make these judgements, within the market framework established by government. The actual costs and economics of new nuclear will depend on, amongst other things, the contracts into which developers enter, and their cost of capital for financing the project.

In evidence to the Trade and Industry Select Committee, the Energy Minister, Malcolm Wicks, was blunter¹⁰⁸.

It is not for government to say that we shall have X nuclear reactors and so on. Government will not be building nuclear reactors, will not say they want X number of nuclear reactors. I always thought myself that if at the moment one fifth of our electricity is from nuclear, if the market came forward with something to replicate that broadly in the future, from my own point of view it seems to me that would make a useful contribution to the mix. We are not going to do anything to facilitate that, nor this percentage nor that percentage.

And in response to a question on subsidies ('Is that the Government's position? No direct subsidies and no indirect subsidies. Am I clear on that?'), he said:

No cheques will be written, there will be no sweetheart deals.

And

No, there will not be any special fiscal arrangements for nuclear. It should not be a surprise, with respect, because we have said it very clearly in the Energy Review. You could pursue this if you wanted by saying that nuclear waste is quite a complex subject and we are going to look very carefully at that to make sure that the full costs of new nuclear waste are paid by the market.

The main concession was on licensing:

The idea of pre-licensing is that you can say here is a wind farm, here is a nuclear reactor or a gas-powered station let us pre-license it so that the regulators are satisfied that it is safe and all the other things as a piece of kit. Then the local inquiry can purely be about local issues rather than becoming a national or international occasion to re-open the whole debate about whether windmills or nuclear are desirable. That is what we are trying to do.

Benefits

In the Government's central cases for gas and nuclear, nuclear has a small cost disadvantage, with the central figure for gas £34.6/MWh (€52/MWh) compared to £37.5/MWh (€56/MWh) for nuclear. The case for nuclear power, unless the central case for nuclear is too pessimistic and/or the central case for gas is too optimistic, therefore rests on an assumption that the strategic advantages of nuclear, for example, reducing gas dependency or increasing low-carbon generation.

The range for the nuclear costs is plus or minus about 20%, compared to nearly 30% for gas (see Table 3.1).

Table 3.1: Costs for nuclear and gas (£ per MWh/€ per MWh)

	Low	Medium	High
Nuclear	30/45	37.5/56	43.7/65.5
Gas	24.5/37	34.6/52	45.2/68

Source: Department of Trade and Industry, 'Nuclear power generation cost benefit analysis' July 2006 <http://www.dti.gov.uk/files/file31938.pdf>

Assumptions

However, to determine whether this cost can be seen as a reliable, it is necessary to scrutinise the key assumptions to check how plausible they are (see Table 3.2)

Table 3.2: Assumptions adopted in the UK CBA

Variable	Assumption
Construction cost	£1250/kW (€1875/kW)
Construction time	72 months
Load factor	80%, rising to 85% after 5 years
Operational life	40 years
O&M cost	£7.7/MWh (€11.5/MWh)
Fuel cost	£3.9/MWh (€11.8/MWh)
Decommissioning cost	£400/kW (€600/kW)
Discount rate	10%

Source: Department of Trade and Industry, 'Nuclear power generation cost benefit analysis' July 2006 <http://www.dti.gov.uk/files/file31938.pdf>

Construction cost

The UK Government claims that it is assuming an overnight capital cost equivalent to the reported price of the Olkiluoto order plus 20%. At first sight, this seems a sensibly conservative estimate reflecting, for example, the possibility that the Olkiluoto contract has been under-priced. However, if we look at the assumptions, this conservatism is less apparent

The cost of the Olkiluoto plant has been widely reported as €3bn, which equates to €1,875/kW for a 1,630MW unit. In December 2006, the £/€ exchange rate was 1.5, which makes the cost £1,250/kW or a total of £2bn. However, in the past six years, the exchange rate has varied between 1.36 and 1.75, a variation of nearly 30%. This variability alone should raise questions about whether the risk analysis really reflects the extent of the risk. Most of the equipment and fuel will be priced in international currencies and if the pound falls against the Euro, the sterling cost will go up. An increase in cost of 10-15% is by no means implausible from currency exchange rate variability alone.

The reported €3bn cost for the Olkiluoto plant includes interest during construction (IDC) and the cost of two reactor cores¹⁰⁹. Conventionally, comparisons of construction cost exclude IDC but include the cost of the first fuel charge. So to standardise the Olkiluoto cost we need to subtract the IDC and the cost of one reactor core. The CBA does not appear to make an adjustment for the cost of the second core. The cost of the Olkiluoto plant, excluding IDC is assumed to be £1,050/kW. The CBA does not specify the assumed exchange rate, but if we assume the analysis was based on May 2006 rates when the £/€ exchange rate was about 1.45, this translates to a construction cost of about €1,500/kW or about €2.5bn. Given that, as acknowledged by the CBA, most of the finance was borrowed at an interest rate of only 2.6%, this seems a little high. If the €2.5bn had all been borrowed at the start of a construction period of four years, the interest during construction would only have amounted to €270m, so IDC may be no more than about €150m with such low interest rates. On these grounds, the assumed cost of the Olkiluoto plant seems to be an under-estimate.

The CBA claims that the assumed cost for a UK plant would be £1,250/kW, about 20% more than Olkiluoto. This premium is based on three factors:¹¹⁰

- 'The possibility that costs of this project have been discounted as part of a wider marketing strategy.
- The possibility that costs have been underestimated.
- Potentially more onerous regulatory requirements in the UK as opposed to the Finnish context, notwithstanding arguments above that planning process design can reduce pre-development and construction costs.'

The first two explanations are clearly valid although the third explanation does have a rather jingoistic flavour and is hard to justify. To balance these upward price pressures, the CBA offers grounds for the price to be lower (CBA, p 18):

'The central case is regarded as being conservative, particularly because the cost for the TVO Project relates to one plant rather than a nuclear programme. Unit construction costs for a programme are estimated to be 25% or more lower than for the addition of one plant. The differential

reflects one off costs (e.g. finalising a design to meet national regulatory requirements) and possible scale/scope economies associated with programme build (e.g. through batch production of components). The central case assumption builds in a 40% premium relative to the French forecast overnight cost for a 10 GW programme.⁷

These assumptions are rather less plausible. Whether 3 or 4 orders can be regarded as a programme is questionable. It is not clear whether the Review's assumptions on how construction costs fall with experience can be reconciled with the views of the PIU, which assumed minimum achievable costs would only be achieved after 8 units have been built and if units are built as pairs.

Whether, in a competitive market, a utility could commit to build 4 units is even more dubious. If we assume there are still about 6-8 main generators in the UK market when the first order is expected to be placed, they would have a capacity each of about 10GW. For one of these to make a decision to build the equivalent of 60% of their capacity with one technology at one time would appear an enormous risk. The only circumstances in which it would be possible would be if wholesale electricity competition no longer existed or the main generators had formed a consortium to build these plants. Again, this would be feasible only if competition between generators was superficial.

The assumption that building several plants would reduce costs is logical. However, French experience with its nuclear programme is very different. It is worth noting that from 1974 to 1984, when EdF completed more than 30 nuclear units, the real cost of the plants actually increased by 54%¹¹¹.

The Flamanville 3 order, expected to be placed in 2007, is expected to cost **€3.3bn**. However, this cost does not include the cost of the first fuel core or the interest during construction. The UK Government's CBA notes that Electricité de France (EdF, the main French utility) expects Flamanville 3 will cost 10% more than Olkiluoto. However, adding on the first fuel core will significantly increase this cost, perhaps by 10-20%. This already takes the cost estimate up to the level assumed by the UK Government for the first UK unit. This makes the UK estimate seem significantly less cautious than is suggested in the CBA for two main reasons:

- Historically, forecasts of nuclear plant construction cost almost invariably turn out to be under-estimates so it is likely the Flamanville plant will cost more than is currently forecast.
- France is the most experienced builder of nuclear plants in the world in the past 30 years, ordering and completing about 50 plants in that time, whereas the UK has ordered only three plants in that time, two of which used a completely different technology. Its record of completing these three plants to time and cost was poor.

Construction time

The assumed construction period is 72 months from placement of order to commercial operation. This compares to the 48 months forecast for Olkiluoto and 54 months forecast for Flamanville 3. However, these periods appear to be from first structural concrete (which often occurs up to a year after placement of order) to first criticality (which precedes commercial operation by about 6 months) so the

assumption is similar to that adopted by EdF. Olkiluoto is already 18 months late after only 18 months of construction, so this assumption is far from conservative.

Load factor

The CBA again stresses that the assumed load factor is conservative. It is indeed in line with experience at Sizewell B, where after 10 years of operation, the cumulative load factor is 85% (this makes it by far the most reliable plant built in the UK). This assumption therefore seems reasonable although it is by no means assured that the target will be met.

Operating life

Again, the CBA stresses that the assumed lifetime is very conservative, 40 years compared to the design life of 60 years. From an economic point of view, with an assumed real cost of capital of 10%, the difference between assuming 40 years and 60 years is negligible. Any benefits earned more than 40 years in the future would have a tiny 'present value'.¹¹²

For an economic analysis, the relevant measure is not the physical life, but the economic life. While the economic life cannot exceed the physical life, it is highly likely the economic life will be shorter than the physical life. Power plants are generally retired when they are no longer economic or would cost more to keep in service than they would earn, not when they are thoroughly worn out. Making an assumption about the type of power plant that would be economic in, say, 2060 is heroic. This is especially so in competitive markets where plants that are uneconomic will be quickly retired. It is worth remembering that British Energy collapsed financially in 2002, when the Sizewell B plant was only 7 years old. Had the UK Government not chosen to rescue the company, at huge expense to the taxpayer, it is questionable whether a buyer would have been found for Sizewell B. If, as seems entirely plausible, British Energy fails again, the chances of finding a buyer are even more remote.

O&M cost and fuel cost

British Energy publishes figures on the operating cost of its 8 plants. These costs have increased from about £16/MWh (€24/MWh) in 2002 to about £25/MWh (€37/MWh) in 2006, far above the level assumed for a new plant of £11.6/MWh (€17.4/MWh). However, experience to date with UK reactors may not be a good indicator of operations and maintenance (O&M) costs of future plants because only one of British Energy's stations is a PWR comparable to the type of plant that might be built.

The USA does collect and publish operating costs and in 2004, the average was \$17.2 (€13.1). At an exchange rate of £1=\$2.0, this equates to about £9/MWh. However, the dollar was very weak against sterling in December 2006 and at more realistic rates, the assumed value may be about the same. The main factor that might increase UK costs compared to US costs is that US costs include a figure of \$1/MWh (€1.33/MWh) to dispose of spent fuel. This is a nominal sum, set nearly 30 years ago and does not reflect real experience. A more realistic figure is likely to be significantly higher.

Nevertheless, the assumed figure does appear to be reasonable, although again, particularly if the reliability was worse than forecast, it could easily prove too low.¹¹³

Decommissioning cost

The CBA assumes a decommissioning cost of £636m (€950m) or £400/kW (€600/kW). This must be regarded as a highly speculative figure given that no full-size nuclear power plant that has completed a significant number of years of service has ever been fully dismantled and disposed of¹¹⁴. A particular uncertainty is the cost of full decommissioning and disposal of waste. Estimating the cost of decommissioning and clean up alone, has been described by one former BNFL insider as 'more of an art than a science'.¹¹⁵ This is especially true for intermediate level waste, high level wastes and spent nuclear fuel for which no facilities exist in the UK. While this figure is in line with forecasts, it is significantly less than the latest estimates for the UK first generation plants that are in the early stages of decommissioning. The costs per kW are highly variable, ranging from £4000/kW, to about £1000/kW. While these costs are for a very different technology, it is worth noting that the estimates are necessarily much more fully developed than those relating to plants not even built yet and, in the past 15 years, the estimated cost has gone up by a factor of about 6.

Of perhaps as much importance as the amount estimated is the way in which the provisions are held and the assumptions on what rate of interest any provisions would earn. It is assumed that any new plant owner would have to operate a segregated decommissioning fund: in other words, a fund that the plant owner would not be able to access for purposes other than decommissioning. If the provisions are expected to earn even a relatively moderate real rate of interest, say 5%, and provisions are collected over the life (say 40 years) of the plant, the impact will be much less than if the plant owner is required to provide the funds on the day the plant starts and the fund is expected to earn, perhaps 2% real for, say 20 years. The latter arrangement would reflect an arrangement where funds could only be invested in very low risk investments and a funding shortfall would be much less likely if the plant failed to complete its expected life. For example, a fund that grows at 5% per year will grow by a factor of 7 over 40 years, while a fund that grows by 2% over 20 years would only grow by a factor of 1.5.

The CBA does not specify its assumptions in this respect. It states (CBA, p 4):

Back end costs (decommissioning and waste management), whilst potentially of a large order of magnitude far into the future, would need only a relatively small annual contribution over time to ensure that the required amount is available. No decisions have been taken on the specific mechanism required.

This implies that funding would be drawn over a relatively long projected life, rather than at the start of operation and a significant positive interest rate is assumed.

If we assume a low interest rate (2%), a lifetime of 20 years and a decommissioning cost of £636m (€934m), this would require that the plant owner would deposit (and obtain guarantees to ensure the full sum was available even if the plant did not operate for 20 years) about £400m (€588m), effectively increasing the construction cost by about 20%.

Cost of capital

This is the assumption that is crucial and most controversial.

When the Performance and Innovation Unit (PIU) of the Cabinet Office examined nuclear economics in 2002 for the Government's 2003 energy review, the PIU took a range of discount rates (real post-tax cost of capital) – 8% and 15% – the 8% rate corresponding to the rate applied to appraisal for Sizewell B when the electricity industry was a publicly owned monopoly. The 15% discount rate produced costs per kWh about 50% higher than the 8% rate.

At that time, 15% was widely seen as the minimum rate required for any power plant operating in the competitive market. It is therefore surprising that the CBA takes as its central case 10% with a high case of 12% and a low case of 7%. It is hard to see, given the government strictures on subsidies, how a 7% rate could be feasible, while even a 10% rate would represent a very low risk investment not consistent with a plant that had to operate without special taxpayer or electricity consumer support.

Unless the Government's statements on subsidies and guarantees are not to be taken seriously or the Government assumes that by the time the plant is ordered, the wholesale electricity market will be so lacking in competitive pressure that plant owners are effectively able to recover all cost incurred from consumers, no matter how imprudently incurred, even the 12% 'high' case seems far too low.

Capacity need

The CBA states:¹¹⁶

There is a relatively small need for new capacity between 2018-2025. The economic analysis suggests that new investment should only take place when there is a need for capacity: to replace existing capacity upon retirement and to meet demand growth.

This is a particularly curious suggestion given the Government's stated intention to allow the market to determine investment decisions. According to this market philosophy, a plant will be retired when it is no longer profitable and built when it is expected to be profitable. The idea that a company could make a decision in 2007 about whether there will be a need for capacity in 2021 is preposterous. The UK market has swung from large surplus in 2002 to near shortage in only 3-4 years as companies responded to low electricity prices by retiring old plants and postponing investing in new plants, so the suggestion that there will be a small capacity need between 2018 and 2025 represents a misunderstanding of how markets operate and cannot be taken as a given. In markets, investments are taken as the result of market signals, not government planning, and the existence or otherwise of a capacity need in 2021 will be the consequence of many commercial decisions taken between now and then.

Reactor technology and vendor choice

While the Government has repeatedly stated that decisions on nuclear power will be taken by the private sector, the logic of the Government's programme is that it will choose the reactor technology and vendor. The process of obtaining regulatory and planning approval is expected to start in 2007, leading to plant order in 2015. Does the Government really believe that it is feasible, in a competitive electricity market, for a company

to commit to build a reactor 14 years before that plant comes on-line? Even committing to a new nuclear power plant 6 years in advance, a period during which the market could swing from shortage to surplus and back again, stretches belief. From the Government's current position it appears to follow that it will choose the reactor technology and frame the regulatory approval for it. Obtaining regulatory approval for all the feasible designs would be hopelessly wasteful and would stretch the regulatory bodies' already over-extended resources far too far. The US Government has chosen this option, but with a much better resourced regulatory body and at huge cost to US taxpayers. If, when the time to order the plant came, the design proved uncompetitive compared to its rivals, the process might well have to go back to square one unless measures were introduced to support the design originally chosen.

Evaluation of the UK's proposed programme

What is striking from the Government's analysis is that the economic benefits, even with some highly suspect assumptions on economic parameters promise only slender returns and only in the more favourable scenarios. The benefits are strategic, mainly relating to the reduction of greenhouse gas emissions. The CBA states, that nuclear power is justifiable on the following grounds:¹¹⁷

- Adding new nuclear capacity could help to reduce forecast carbon emissions and to reduce the level of forecast gas consumption imports;
- Within power generation, new nuclear appears to be a cost effective means for meeting carbon emissions reduction targets. Adding new nuclear capacity would not preclude investment in other forms of low carbon generation;
- Investment in nuclear new build would result in carbon abatement cost savings sufficient to offset the nuclear cost penalty relative to gas fired plant in a central gas price scenario;
- Adding new nuclear power station would also partially mitigate risks associated with dependence on imported gas. In particular, costs associated with insuring against the risk of fuel supply interruption (e.g. through adding gas storage capacity) could be reduced as nuclear plant is added. Investment in new nuclear capacity would also provide a hedge against the risk of high gas prices; and
- Nuclear investment is not justified at the higher end of the range of costs, or in a low gas price world, or in a central gas price world where there is no carbon price.

Yet the Government states:¹¹⁸ 'Any new nuclear power stations would be proposed, developed, constructed and operated by the private sector.' Why private, profit-maximising companies should decide to invest in nuclear power, given all its specific economic risks, when, in the Government's central case, with dubious assumptions, there are no clear economic benefits to them is a mystery.

If the Government expects private industry to make decisions where the primary benefit is a strategic national one, it will have to compensate industry for the additional costs and risks it is taking. The Government has very clearly stated it will not do this: 'No cheques will be written, there will be no sweetheart deals.'

In summary, the idea that 'nuclear power is back with a

vengeance' is not supported by the scale of the programme envisaged, even if the programme was capable of being realised. The assumptions on which the Government's case for nuclear power plants rests, while significantly less outlandish than many recent forecasts, are still optimistic. A particular concern is the choice of a very low discount rate, a rate that would only be feasible if taxpayers and/or electricity consumers were shouldering the economic risk of the programme, an outcome the Government appears to have totally ruled out. On many criteria, the programme is impractical. It would require companies to make decisions on plant construction far in advance of when the plants would come on-line, an option only feasible in a planned monopoly electricity industry. It would require the Government to make a choice of technology and vendor, a decision it has no powers to make in a liberalised energy market.

In February 2007 the High Court declared that the Government's decision to back the construction of new nuclear power plants was unlawful. The judge overseeing the case, brought by Greenpeace, declared that the consultation process was "seriously flawed and that the process was manifestly inadequate and unfair" because insufficient information had been made available by the Government for consultees to make an "intelligent response". In particular the judge criticised the Government for the lack on information available during the consultation on economics and nuclear waste.

As a result of this decision the Government will in 2007 undertake another public consultation process on nuclear power before finalising its policy towards nuclear new build.

USA

There are 103 commercial nuclear reactors in operation in the United States, making it the largest, by some margin, commercial fleet in the world. However, this fleet is the result of ordering and construction in the 1960s, 70s and 80s, and no new reactor has been ordered for 30 years that was not subsequently cancelled.

The collapse and cancellation of orders was in part due to the increase in costs associated with new build. Reactors being completed in 1976/7 were 3.4 times more expensive per kW than those in 1966/7. This has been accredited to the rapid progress to larger power plants, the non-emergence of the expected economies of scale and changes in design and equipment¹¹⁹.

The Bush administration has made a concerted six year effort to revive nuclear ordering, including its Nuclear Power 2010 programme, launched in 2002. It has yet to achieve a new order. The programme focuses on Generation III+ designs (see below). Under the programme, the US Department of Energy (USDOE) expects to launch cooperative projects with industry:

'.. to obtain NRC approval of three sites for construction of new nuclear power plants under the Early Site Permit (ESP) process, and to develop application preparation guidance for the combined Construction and Operating License (COL) and to resolve generic COL regulatory issues. The COL process is a 'one-step' licensing process by which nuclear plant public health and safety concerns are resolved prior to commencement of construction, and NRC approves and issues a license to build

Table 3.3: Construction/operating license (COL) applications

Applicant	Site/no of units	Technology	COL submission date
Amarillo Power	TBA / 2	ABWR	TBA
Dominion	North Anna / 1	ESBWR	11/2007
Duke	Cherokee / 2	AP1000	10/2007
Entergy	River Bend / 1	ESBWR	5/2008
Exelon	Clinton / ?	TBA	11/2008
NRG Energy	TBA / 2	ABWR	Late 2007
NuStart/Entergy	Grand Gulf / 1	ESBWR	11/2007
NuStart/TVA	Bellefonte / 1	AP1000	10/2007
Progress	Harris / 2	AP1000	10/2007
Progress	TBA / 2	AP1000	7/2008
SCANA	Summer / 2	AP1000	10/2007
Southern	Vogtle / 2	AP1000	3/2008
TXU	Comanche Peak / 2	TBA	Late 2008
Unistar	Calvert Cliffs / 1	EPR	Late 2007
	Nine Mile Point / 1	EPR	Mid 2008

Source: Nuclear News, January 2007, p 26

Notes: Excludes applicants that have not identified a site or technology

and operate a new nuclear power plant.¹²⁰

A total of up to \$450m (€342m) in grants is expected to be available for at least three projects. Two main organisations have emerged to take advantage of these subsidies and have signed agreements with the USDOE to develop COLs. Nustart, launched in 2004, was the first utility grouping to express an interest. It comprises a consortium of eight US utilities including Constellation Energy, Entergy, Duke Power, Exelon, Florida Power & Light, Progress Energy, Southern Company and the Tennessee Valley Authority (TVA, providing staff time not cash). The French utility, EdF, and the vendors, Westinghouse and GE are also members but have no voting rights.

This was followed up by the nuclear provisions of the US Energy Policy Act of 2005 (EPACT 2005). The Bush programme is best understood as an effort to reverse the power market lessons of the 1980s and 1990s. Since investors have proven unwilling to assume the risks of building new nuclear units, even after all the improving of designs and streamlining of the licensing process, EPACT 2005 reverts to the 1960s and 70s by reassigning risk back to those who are given no choice, this time the taxpayers instead of the customers.

The most important nuclear provisions of EPACT 2005 offer three types of support. First, a limited number of new nuclear power plants can receive a \$18/MWh (€13.5/MWh) production tax credit for up to \$125m (€93.75m) per 1000MW (or about 80% of what the plant could earn if it ran 100% of the time).¹²¹ The second benefit is a provision for federal loan guarantees covering up to 80% of project costs. The third benefit provides up to \$500m (€375m) in risk insurance for the first two units and \$250m (€187.5m) for units 3-6. This insurance is to be paid if delays not the fault of the licensee slow the licensing of the plant.¹²²

These provisions lower the price of nuclear power without lowering its cost, at least not for many years. This occurs because some of the costs and risks are moved out of the price charged to customers and onto the shoulders of taxpayers. For example, the production tax credit deprives the US Treasury of funds that must be made up from other sources. Whether the benefit flows through to customers or is retained by investors

will vary with the economic regulatory approach used, but either way prices can be kept lower than would be the case if the credit did not exist. Similarly, the loan guarantees assure lenders that they will be repaid no matter what happens at the power plant. Essentially, their guaranteed loans are converted into government obligations. This lowers both the interest rate and the amount of more expensive equity capital that must be raised, as was used for the financing of the Olkiluoto 3 reactor in Finland.

Taken together and combined with other benefits recently conferred on the industry in the United States (such as the 20 year extension of the law limiting nuclear power plant exposure to liability for the costs of a serious accident)¹²³, the benefits in the recent U.S law have substantially increased the likelihood of a new US nuclear power plant order in the next few years. Indeed, the incentives are structured to provide maximum benefit to plants ordered before the end of 2008 (see Table 3.3 for a list of possible applicants.

At a recent conference, three US industry CEO's made clear the impact of the 2005 Congressional action:

[TXU CEO John Wilder] said there were now projects totalling about 26 gigawatts lining up for limited federal incentives, which could provide 'anywhere from a \$2 per megawatt-hour advantage to a \$20 per megawatt-hour advantage.' He said he didn't believe it would be known which companies would receive those benefits until about 2012. 'Quite frankly, that's all the difference between these projects working or not working,' he said.

NRG Energy President/CEO David Crane, also speaking on a September 26 conference panel with Wilder, said the measures in the Energy Policy Act of 2005 were key to his company's decision to pursue potential construction at South Texas Project. 'I do think those are absolutely necessary to get nuclear plants under way,' he said. 'In fact, until I actually knew what they were, we would not have even contemplated it.'

Exelon Nuclear's [President Christopher] Crane said that the incentives were a key factor in his company's decision to prepare a COL. But other factors would influence whether Exelon commits to building a new reactor.¹²⁴

The significance of such orders for the future of nuclear power is uncertain. Plants ordered between now and 2008 will not be licensed before 2010 and will not be online before 2014 at the earliest. They will have to operate competitively for a few years before their performance can inspire the confidence needed for a fleet of privately financed orders based on principles of standardisation.

All that this round of orders can demonstrate for the near future is that government can build nuclear plants by compelling taxpayers and customers to pay for them.

China

Energy demand in China is growing at a rapid rate. As a consequence there are plans to develop more energy supply in every sector: oil, gas, renewables, coal and nuclear. Currently, nuclear power in China only provides a relatively minor contribution to the country's electricity (1.9%) supply. The country currently operates ten nuclear reactors, built using Canadian, French, Russian and domestic designs. A further four are under construction, one of Russian design, the rest domestic, and in December 2006, four further orders for AP1000 units were placed.

Planned units

Yangjiang and Sanmen

In 2003 preliminary approval was given for construction of 2 units at Yangjiang plant in Guangdong and two more at Sanmen in Zhejiang (near Qinshan). In February 2005 the government agency, the State Nuclear Power Technology Co (SNPTC), closed bids for these four identical units. However, some suggest that it might be that each site might have different reactors. Three companies lodged bids for the construction, Areva, Westinghouse and Atomstroyexport.

Areva: Areva claims that it has the lowest bid and proposes not only full technology transfer but also a series of joint ventures in the nuclear cycle, including for the first time reprocessing. Further reports suggest the deal will involve French assistance with Chinese participation in uranium mines in Niger, Kazakhstan and Mongolia. The design on offer is the European Pressurized Water Reactor (EPR) or potentially the US Evolutionary Power Reactor (US EPR) – largely the same design of reactor.

Westinghouse: In February 2005 the US Export Import Bank gave a \$5 billion (€3.8bn) preliminary commitment for Westinghouse to build four AP1000 units in China. A further detailed examination of the transaction will only take place at the time of the final commitment application. The Westinghouse bid is also reported to include a comprehensive transfer package for production of advanced PWR fuel. The Westinghouse bid is part of a consortium with Mitsubishi Heavy Industries and Shaw, Stone & Webster Nuclear Services. In October 2006 the sale of Westinghouse to Toshiba was completed.

Atomstroyexport: Little information is available about this bid.

In December 2006 the construction contract was awarded to Westinghouse. The total price of the contract was not disclosed and was said to include 'complete and rapid technology transfer' and be in the range of \$5-8 billion (€3.8-6.1bn)¹²⁵, but does not include the cost of the turbine island, which will be part of a separate subcontract. Ground breaking is expected to begin in 2007, with two units scheduled for completion in 2013 and the other two in 2014-15.

It is reported that a framework agreement to govern the sale is expected in early 2007, which will give more details of the financial and technical expectations for the project¹²⁶.

Guangdong

In February 2007, the French press reported that a Memorandum of Understanding (MoU) was signed between EdF and the China Guangdong Nuclear Power Corporation (CGNPC). In this deal EdF is seeking to act as architect-engineer as well as the project owner. Earlier in 2007 Areva also signed a MoU with CGNPC to build two EPRs at Guangdong.

Qinshan

In April 2006 and January 2007 the first construction began on units 3 and 4 respectively. The reactors are 650-megawatt (MW) Pressurised Water Reactor (PWR) units, which use CNP600 technology developed by the CNNC

Weihai

In November 2005 approval was given for the construction of a High Temperature Gas-cooled Reactor (HTGR, a type of pebble bed reactor) by a consortium led by Huaneng Group – the country's largest generating company, but without nuclear experience – with Tsinghua University and China Nuclear Engineering and Construction.

Proposed units

It is reported that the country will spend some 400 billion yuan (€39.4bn) on building new nuclear power plants by 2020, to increase the amount of installed and under construction nuclear power capacity to 40 GW. CNNC expects further expansion to enable a total of 60 GW of installed capacity, accounting for 6% of the country's electricity production.

The first part of this plan is set out in the 11th 5-year plan (2006-10). More than 16 provinces, regions and municipalities have announced intentions to build nuclear power plants, most of which have preliminary project approval by the central government but are not necessarily construction schedules. These total around 40 new reactors. It is reported that provinces will put together firm proposals with reactor vendors by 2008 and submit them to the central government for approval before 2010.

Part 4:

Renewable energy: resource, economics and prospects

The International Energy Agency¹²⁷ has suggested renewables are at a crossroads – ‘no longer a theoretical possibility, but not yet a major market presence’. Including hydro-electricity the proportion of renewables in global electricity generation was about 18% in 2004. Within this figure, geothermal energy, solar, tidal and wind accounted for 334 TWh, or about 2% of global electricity production. In 1990, the corresponding amount was 1%. Since global electricity production has increased by 50% since 1990, electricity production from ‘new renewables’ (i.e. excluding hydro) increased threefold in that time - a compound annual growth rate of 14%. In practice, the growth rates in wind and solar energy have been higher than this, but lower in geothermal and tidal. Annual investment in renewable energy has grown from about \$7bn (€5.3bn) in 1995 to \$38bn (€29bn) in 2005.¹²⁸ During 2005 the total installed capacity of non-large hydro renewables increased by 22 GW, which compares to an increase of 3.3 GW increase in nuclear, much of which relates to increased capacity from existing reactors.

Resource and potential: overview

There are three principal sources of renewable energy: the sun, the moon, and the earth itself. The sun is the source of solar energy and, indirectly, of hydro energy (through evaporation), wind energy, wave energy and biomass energy (through photosynthesis). The moon is the source of tidal energy and the earth of geothermal energy. A good indication of renewable energy resources is provided by Czisch¹²⁹, who suggests that the solar energy potential varies from 1000 kWh per square metre per year in Northern Europe and Canada, to over 2000 kWh per square metre in equatorial regions. Although there is a two to one variation in the solar resource, there are nevertheless numerous applications for solar energy in Northern Europe and Canada, particularly for “off-grid applications”, where the costs of other energy supplies may be very expensive. Broadly speaking, the most attractive regions for wind energy -- which have annual mean wind speeds of 7 m/s and above -- are in

the coastal zones of all five continents, but higher wind speeds are found in many mountain regions and offshore. Wind energy generation costs in zones with lower wind speeds will be more expensive, but not necessarily uneconomic.

High temperatures close to the surface -- suitable for geothermal electricity generation -- are found in parts of central Europe, the Far East, and the western part of the American continent. This chapter focuses only on electricity generation but there is increasing interest in “ground source heat pumps”, which, broadly speaking, can be used anywhere. The further development of hydro power resources is limited, not by the resource potential, but by the availability of suitable sites and these are very restricted in the developed world. Large-scale developments are therefore likely to be restricted to less populated areas in central Africa, parts of Asia and the Americas, but there is further scope for small-scale hydro in many areas, although the total potential is limited.

The prospects for renewable energy may be assessed by examining progress towards the projections for 2010 set out in the European Commission’s White Paper on renewable energy¹³⁰. Table 4.1 reflects the conclusions of a review and includes the latest figures for installed capacity.

The table below shows that wind energy has performed very well, with current European capacity already in excess of the 2010 projection. Hydro (large and small) had more modest growth targets but the projection has already been met, with good performance at the large-scale compensating for slower growth at small-scale. Photovoltaics were given the most demanding projection (a 100-fold increase, albeit from a small base) and are expected to exceed it – but the electricity production is modest. Although biomass electricity output has increased by factor of three since 1995, the further three-fold increase necessary to meet the target is unlikely to be realised. Finally, geothermal energy is expected to come very close to meeting its target.

Table 4.1: EC White Paper Projections, progress and prognosis¹³¹

Date	1995		2010 projection		2005 actual	2010 MW projection will be achieved?
Technology	Capacity, MW	Output, TWh	MW	TWh	MW	
Wind	2500	4	40,000	80	40,455	Already exceeded
Hydro, large	82,500	270	91,000	300	96,418	Already exceeded
Hydro, small	9,500	37	14,000	55	11,600	~10% under
Photovoltaics	30	0.03	3,000	3	1,794	Will be exceeded
Biomass	(1)	22.5		230	68 TWh	No
Geothermal	500	3.5	1,000	7	822 (2)	Slight undershoot

Notes:

1. Some biomass used to ‘co-fire’ with fossil plant, so capacities not relevant
2. 2004 figure

Economic overview

Broadly speaking, gas provides the cheapest electricity in many parts of the European Union and in some of the United States, but many existing hydro sources are already competitive, as they were installed several years ago, so capital costs are now sunk. Of the 'new renewable' energy sources, wind is becoming increasingly competitive where wind speeds are high, for example in Germany, Denmark, northern France, Britain, Ireland, southern Spain, Portugal, China, India and some US states as well as Canada. Numerous islands are also ideal locations for wind and solar energy, as many are not connected to mainland grids and so electricity costs are high, due to the need to import the fuel. Photovoltaics are particularly suited to household applications and island locations due to their modular nature and minimal maintenance requirements.

Future prospects

Table 4.2 summarises data on future projections for the renewable sources, drawing on estimates by the European Renewable Energy Council¹³² and elsewhere. The data has been checked with other sources, particularly the White Paper from the International Solar Energy Society¹³³ and the International Energy Agency¹³⁴. The latter only quotes estimates for 2010 and, for the rapidly developing technologies of wind and

photovoltaics, they are closer to the 'low' estimates from EREC. In the case of the other technologies, the differences between the 'low' and 'high' estimates are relatively modest. For wave and tidal stream energy, mid-range estimates from the Carbon Trust¹³⁵, applicable to Europe, have been doubled to allow for other worldwide developments.

Costs

The larger-scale developments in renewable energy technologies deliver economies of scale and currently have the lowest generation costs and are best able to produce energy in quantities to match the output of thermal plant. In the case of wind energy, for example, not only are installed costs per kilowatt lower with large wind turbines and wind farms but higher energy yields are achieved as the bigger machines reap the benefit of the higher wind speeds that are found at greater heights. There is a much wider range of costs at smaller scales and these are not covered here.

Wind energy

Wind energy has a good combination of resource, proven status and cost. Worldwide growth is following an exponential path, as shown in Figure 4.1, increasing at 25-30% per annum. Capacity at the end of 2006 was over 74,000 MW.

Table 4.2: Projections of renewable energy capacities and electricity generation

Date	2005		2010		2020		Source
Technology	MW	TWh	MW	TWh	MW	TWh	
Wind,							
low estimate	59,206	124	135,543	299	560,445	1375	GWEC, 'moderate growth'
high estimate			153,759	337	1,072,928	2632	GWEC, 'advanced wind'
Hydro,							
large	740,000	2747		3095		3590	EREC, 'advanced policies'
Small	Incl above			220		570	EREC, 'advanced policies'
Photovoltaics,							
low	5,442	6	10,000	12	145,000	175	EREC, 'current policies'
high			18,000	20	230,000	276	EREC, 'advanced policies'
Solar thermal electric	400	2	2154	6	16,854	45	Aringhoff et al ¹³⁶ ,
Biomass		200		390		1010	EREC, 'advanced policies'
Geothermal	8910	55	20,000	134		318	EREC, 'advanced policies'
Wave					3500	9	Carbon Trust (2006), see text
Tidal stream					3500	9	Carbon Trust (2006), see text

If all the projections at the 'high' end were realised, the proportion of renewable energy contributing to world electricity needs would rise from the current level of 18% to 22% by 2010 and 35% by 2020.

Table 4.2: EC White Paper Projections, progress and prognosis¹³⁹

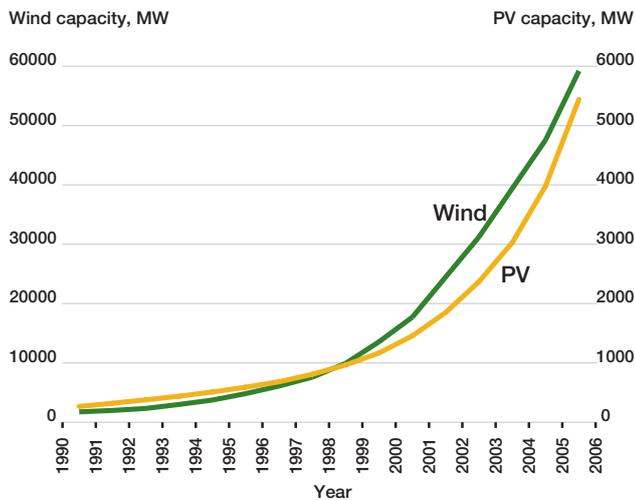
Date	1995	2010 projection	2005 actual	2010 MW projection will be achieved?		
Technology	Capacity, MW	Output, TWh	MW	TWh	MW	
Wind	2500	4	40,000	80	40,455	Already exceeded
Hydro, large	82,500	270	91,000	300	96,418	Already exceeded
Hydro, small	9,500	37	14,000	55	11,600	~10% under
Photovoltaics	30	0.03	3,000	3	1,794	Will be exceeded
Biomass	(1)	22.5		230	68 TWh	No
Geothermal	500	3.5	1,000	7	822 (2)	Slight undershoot

Notes:

1. Some biomass used to 'co-fire' with fossil plant, so capacities not relevant
2. 2004 figure

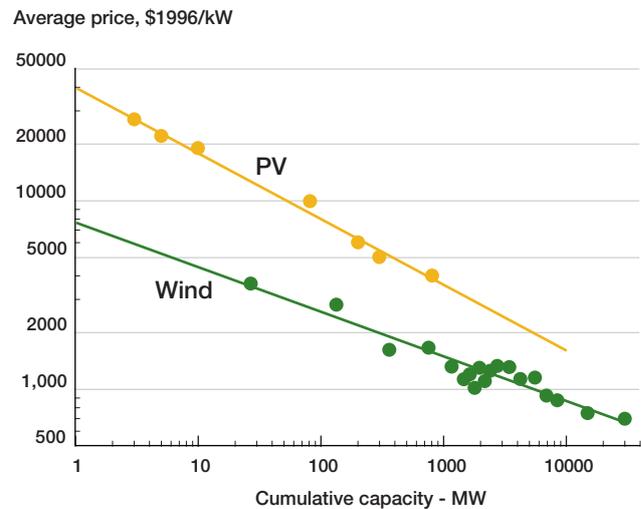
The table shows that wind energy has performed very well, with current European capacity already in excess of the 2010 projection. Hydro (large and small) had more modest growth targets but the projection has already been met, with good performance at the large-scale compensating for slower growth at small-scale. Photovoltaics were given the most demanding projection (a 100-fold increase, albeit from a small base) and are expected to exceed it – but the electricity production is modest. Although biomass electricity output has increased by factor of three since 1995, the further three-fold increase necessary to meet the target is unlikely to be realised. Finally, geothermal energy is expected to come very close to meeting its target.

Figure 4.1: World wind and PV capacity from 1990 to 2005.



Every doubling of global wind energy capacity has been accompanied by a reduction in turbine costs of between 8% and 15%¹³⁷. Figure 4.2 illustrates a typical 'learning curve'; the data used reflects a 15% reduction. Since 2004, an increase in steel and copper prices, and a worldwide shortage of wind turbines, means the fall in prices has ceased. This will have a significant impact on other generating technologies, such as nuclear, which are capital-intensive. By 2005, the average price of onshore wind turbines was €800/kW, and the average installed cost of wind farms was just under €1200/kW.

Figure 4.2: Cost data for wind turbines and solar modules.



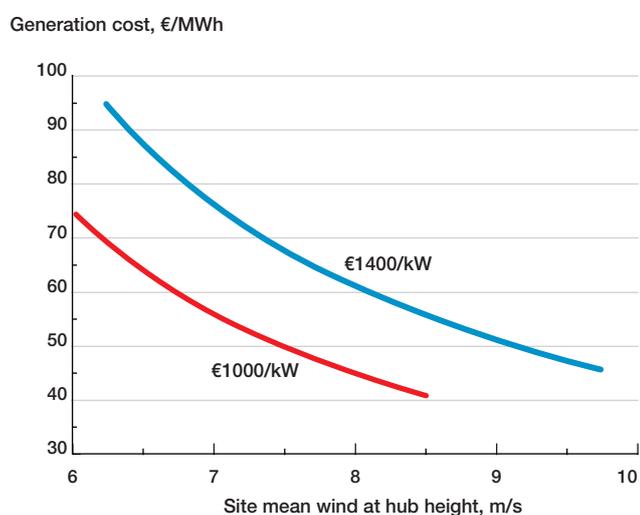
Note that the units used for price do not influence the estimate of the learning rate. Data for the early wind years comes from total shipments from America,¹³⁸ for the central years from data compiled by the Danish Wind Turbine Manufacturers Association (<http://www.windpower.org/>), and the last point (at 30,000 MW) comes from a wind turbine catalogue.¹³⁹ PV data comes from Shell and the World Energy Council.

Alongside the fall in machine costs, the productivity of wind turbines increased as their size increased – in Denmark, for example, from around 1,300 kWh/kW for each kilowatt of capacity installed in 1983, to over 2000 kWh/kW in 1996¹⁴⁰. The combined effect of lower prices and better productivity accounts for the 18% reduction in generation costs per doubling of capacity cited by the International Energy Agency¹⁴¹.

Generation costs depend on wind speed and figure 4.3 shows estimates for €1,000/kW and €1,400/kW, which takes in most of the spread. Lower installed costs tend to be associated with

lower wind speeds sites and the figure shows generation costs of €75/MWh at 6 m/s, down to €49.4/MWh at 7.5 m/s. At the upper end of the installed cost range, generation cost range from €64/MWh at 7.8 m/s, down to €51/MWh at 9 m/s.

Figure 4.3. Generation cost estimates for onshore wind.



These have been calculated using an 8% test discount rate and 20 year repayment period. The discount rate is typical for mature technologies in the private sector and this repayment period is commonly used for wind energy projects. If a 6% discount rate - more typical of 'public-sector' utility projects is used, generation costs are about 12% lower.¹⁴²

Similar curves can be generated for solar energy, with incident solar radiation as the independent variable, and for wave energy, with wave power per metre as the independent variable. To simplify the data for comparative purposes, representative load factors have been used, linked to typical wind speeds, solar radiation levels and wave power. In the case of wind energy, the load factor range is from 15% (the overall average for all German wind plant) to 30% (the overall average for all UK wind plant).

A review of future costs by the Sustainable Development Commission¹⁴³ suggested that installed costs onshore in 2020 will lie between 55% and 92% of the 2001 level. Applying a cautious multiplier of 81% to the 2005 level¹⁴⁴ - after costs had risen - suggests the 2020 level may be around €960/kW, provided there are no further rises in steel costs. Table 4.3 suggests that there will be at least three doublings of capacity by 2020, so the 20% reduction by this time reflects a modest 7% reduction per doubling. A more optimistic cost projection from GWEC¹⁴⁵ suggests €760/kW. A conservative load factor for 2020 of 25% assumes that most of the higher wind speed sites will have been utilised by then.

Offshore wind is less well developed, with worldwide capacity around 750MW, but there are substantial plans in the pipeline. Two of the estimates in the Sustainable Development Commission report suggest installed costs by 2020 will be about 57% of the 2003 level. Taking a figure of €1,800/kW for the latter suggests the 2020 figure will be around €1,200/kW. A similar estimate is quoted by de Noord.¹⁴⁶

Recent projects: Onshore – Summerview, Alberta, Canada. 38, 80 m diameter wind turbines, each rated at 1.8MW (68.4MW total). Annual generation: 208GWh. Project cost C\$100m (€70m), completed 2004. Source: Vision Quest and Windpower Monthly, December 2004.

Offshore – North Hoyle, off north Wales coast, UK. 30, 80m diameter wind turbines, each rated at 2MW (60MW total). Annual generation 191GWh. Project cost £81m (€120m). Completed 2004. Source: DTI

Photovoltaics

Photovoltaic capacity, like wind, has been growing rapidly, as shown in figure 1, and now exceeds 5,000MW, although only about 1,800MW of this was grid connected at the end of 2004. Prices have fallen by a factor of around five since the 1980s and grid connected systems now cost around €5,000/kW. As with wind, prices rose in 2004/5 due to rising demand and increased silicon prices, but the downward trend is expected to continue.¹⁴⁷ The data plotted in figure 4.2 suggests a price reduction per doubling of capacity of 22% and other studies have yielded similar estimates.¹⁴⁸ The International Energy Agency in its 2000 report suggested generation costs fell by 35% per doubling of capacity between 1985 and 1995, reflecting improvements in the efficiency of the systems. Although the contribution to electricity supplies is expected to be modest, markets in the developing world are substantial and this is the driving force behind much of the work currently in progress.

Estimates of installed cost for 2020 show some variation. The Danish Energy Authority¹⁴⁹ suggests €2,000/kW and the International Energy Agency¹⁵⁰ around €1,500/kW. A mean value of €1,750/kW is roughly consistent with a price reduction per doubling of capacity of 20%. Generation cost estimates for 2020 take into account, in addition, improvements in the efficiency of the systems.

Recent project (under construction): Serpa Solar Power Plant, Portugal. 52,000 PV panels, with tracking system. Rated output 11 MW, greenhouse gas saving 30,000 tons/year. Project costs €59m. Source: Powerlight Corporation and Modern Power Systems, June 2006

Solar Thermal Electric (concentrating solar power)

The world solar thermal electric capacity is currently modest (around 400 MW). There is a wide spread of current costs (between €1700-2400/kW) and load factors are around 21%. By 2020, installed costs are expected to fall to around €1000/kW, with load factors reaching 30%.

Recent project (completed 2006): 'PS10' power plant, Sanlucar, near Seville, Spain. 624 tracking heliostats focused on steam generator producing steam at 40 bar, 250°C. Rated output 11 MW, generation 23 GWh. Project costs €35m. Source: www.solarpaces.org

Hydro

Hydroelectric is the best established of all the renewable technologies. 740,000 MW are spread across the world and generated 2620 TWh, 17% of all electricity in 2005. Capacity has grown at just under 2% p.a. over the past 10 years. The scope for further development of large-scale hydro in the developed world is modest, with the possible exception of Canada, and there are only limited opportunities for cost reduction or technical improvements. In the developing world there may be further scope, subject to such projects being environmentally and socially acceptable. The scope for further deployment lies in ingenuity in installing new 'small' (under 10 MW) systems, including run of river schemes, some of which are only tens of kilowatts in size.

Planned project (small scale): Mira, Ecuador. 1 MW output, annual generation 8.1 GWh. Project cost \$1.9m (€1.5m). Source: International Water Power and Dam Construction, July 2005.

Biomass

Biomass refers to material of plant or animal origin. When converted to energy it is low or zero carbon, as the CO₂ emitted is not from fossil fuel origin, but from the current/recent carbon cycle. As well as dedicated biomass plant using e.g. forestry or agricultural residues, biomass can be grown specifically for the energy uses. These "energy crops" are grown for power generation, heat production or for the manufacture of transport bio-fuels.

Municipal solid waste – MSW or industrial and commercial waste ICW can also comprise of or contain significant proportions of biomass. MSW in the UK typical comprises around 65% biomass. Landfill gas and sewage gas is also derived from biomass sources, and is thus regarded in EU and UK policy as a renewable energy source.

UK engineering institutions are pushing for waste management policy to be guided by the climate change agenda, rather than

targets for outcomes such as recycling rates. It may not always be best, from the objective of reducing global warming to recycle wastes, energy recovery could be a better overall environmental option.

Worldwide biomass electricity-generating capacity is now about 39 GW and electricity production is expanding in Europe, driven mainly by developments in Austria, Finland, Germany, and the United Kingdom. The latter has seen recent growth in 'co-firing' (burning small shares of biomass in coal-fired power plants).

Landfill gas and waste combustion are among the cheapest electricity generating costs. However the landfill gas resource in Europe will decline as less waste is landfilled in the future as a consequence of the Landfill Directive. The Energy from waste sector should benefit though less waste being landfilled, as more is likely to be converted to energy. Operators are paid a "gate fee" for taking the waste, and the economics can be favourable, however site acquisition can be a difficulty, so growth may be retarded by the difficulty of obtaining planning consents.

Characteristics common to most sources are small plant sizes (generally not exceeding about 10MW); there are no technical problems inhibiting the construction of large plant but logistical problems arise in moving large quantities of waste products over large distances and, in the case of energy crops, finding sufficient land near the plant. Generation costs vary widely – between €30/MWh for landfill gas and large biomass plant, up to around €90/MWh for advanced gasification plant, but the latter costs are expected to fall by 2020. For consistency, data for two types of plant has been drawn from the Danish Energy Authority.¹⁵¹

- Large-scale plant (up to 400 MW) burning residues from wood industries or forests and residues from agriculture (straw), often delivered as pellets.
- Gasification plant with higher efficiency, fed on wood chips, industrial wood residues, straw or energy crops.

The EU projection for 2010 was 230 TWh, indicating that the potential is large, but it is unlikely to be realised (Table 4.2)

Recent project: Simmering, Vienna, Austria, commissioned October 2006. 23.4MW output (summer), 15MW, plus 37MW (thermal) in winter. Fuel: fresh wood from forestry. Project cost: €52m. Source: Modern Power Systems, June 2006 and www.oekonews.at

Geothermal energy

The best geothermal resources are in the Pacific Rim, especially New Zealand and the Philippines, the United States, Iceland and Italy, which has the highest capacity of geothermal electric generation in the EU, but France, Germany and Belgium have several schemes for thermal purposes and smaller amounts for electricity generation. Most schemes use

warm water reservoirs, but research is in progress into ways of improving drilling processes, using 'hot dry rocks' as a heat source, and into alternative thermal cycles for harnessing the heat. Installed costs vary considerably as they depend on the depth of drilling required and recent contracts span a range from €1,000/kW (Costa Rica) to €3,000/kW (Canada, New Zealand). There is a matrix of generation costs that depends on the drilling depth and the temperature of the water that comes to the surface. The Geothermal Energy Association¹⁵² suggests that electricity costs for most projects are in the range €44/MWh to €60/MWh.

Recent project (planned): 25.5MW plant in California to generate 200GWh/year. Estimated cost \$90m (€70m). Source: Western Geopower Corp

Tidal barrages

Although the technical feasibility of tidal energy is not in doubt, load factors tend to be low, which leads to high electricity generation costs. France hosts the only large size commercial tidal barrage (240MW). Canada has a smaller project (20MW) and has considered expanding that capacity. India, Australia and China are also examining the potential. A major British project – the Severn barrage – has been under consideration for many years and costings from this are used in Table 4.4.

Existing project, operating since 1966: La Rance, France - barrage length 750 m, 240 MW rated output. Average tidal range 8 m. Output 438-600 GWh. 10-year refurbishment programme nearing completion. Source: EdF and Second international symposium on wave and tidal energy, Cambridge, England, 1981. BHRA Fluid Engineering

Wave energy

Research into wave energy has been in progress since the mid-1970s, in Britain (whose programme was suspended from 1982 to 1999), Norway, Denmark, Japan and the United States. The first commercial devices are now under test, and installed costs are in the range €1500/kW to €2500/kW. However, there is insufficient performance data to produce robust current generation costs for Table 4.4.

Future wave energy costs will be critically dependent on how rapidly the technology is deployed. Sorensen¹⁵³ suggests a goal 'well below €1430/kW' by around 2016, and Ragwitz¹⁵⁴ et al suggests costs will fall to 60% of the 2002 level by 2020. Using the current levels quoted above, this implies a range between €900/kW and €1500/kW and this has been used for the generation cost estimates. The results are consistent with data from the 2006 Carbon Trust report – which quotes generation costs as a function of cumulative capacity – and with the International Energy Agency in 2003, which suggests €1000/kW will be reached by 2030.

Project planned: Off Pavao de Varzim, N Portugal. Three 'Pelamis' P-750kW machines, each 150m long, 3.5m diameter. Cost €8m. Source: Ocean Power Delivery Ltd.

Tidal stream energy

The currents in tidal streams and marine currents can be harnessed in a similar way to wind energy, especially where topographical features amplify tidal movements. (Tidal streams are currents that flow with the tide, whereas marine currents are more or less constant). The advantages of the technology are straightforward: the energy availability is accurately predictable; visual impact is close to zero; and there are few environmental disturbances. While the resource is potentially large, commercial exploitation requires stream velocities of around 2 m/s or more, which substantially reduces the feasible sites. As with wave energy, there is a very limited database of present-day costs and performance. Forecasts of future installed costs are also very similar to those of wave and so, in the light of the uncertainties, a common set of data is used.

Recent project (R&D): Lynmouth, Devon, UK. Installed 2003, currently under test. First commercial-scale 11m diameter rotor, rated at 300kW. Operates with the tide in one direction only. Cost £3.4m (€5m)

Electricity costs

Current plant costs and performance

Table 4.3 summarises the key cost and performance parameters associated with renewable energy systems at present. 'Load factor' has the usual definition of the ratio between the average output and the rated output.

The costs quoted aim to indicate the levels that encompass a wide range of installations, but do not include all projects. Wind energy load factors, for example, range from around 12% to 51%.

Generation costs have been derived for two test discount rates - 5% and 8%. The lower figure is in line with Nuclear Energy Agency¹⁵⁵ practice and the latter is an up-to-date figure for mature technologies financed by the private sector¹⁵⁶. The capital repayment period is 20 years. The table also includes current payments from the German and Irish 'feed in tariffs', to corroborate the estimates in the preceding columns, although it may be noted that German wind speeds are quite modest which leads to relatively high payments. Further corroboration comes from actual contract prices where data is available.

Table 4.3: Current data: Indicative installed costs, performance data and generating costs for renewable energy.

Technology	Installed costs, €/kW	Load factor, %	Generation costs €/MWh				Contract prices
			5% test discount rate	8% test discount rate	German tariff	Irish tariff	
Onshore Wind	1000-1200	15-30	46-72	56-88	84 for ~ 5 years, then 53	57	€45/MWh, Canada
Offshore Wind	1800	33-40	52-63	64-77	91 for ~ 12 years, then 62		€ 67-69/MWh, Denmark
Hydro	1000-1800	50-75	17-43	22-53	37-97 (1)	72	
Solar (PV)	4900-5400	8-16	316-697	393-865	540-570 (1)		
Geothermal	2000-8000	75-95	31-53	38-65	72-150 (1)		€ 46/MWh, California
Large biomass	1300	89	18	23	39-89 (2)	72	
Biomass gasification	3500	85	56	67		70	

Notes: 1. Size dependent. 2. Type dependent.

Table 4.4 2020 data: Installed costs, performance data and generating costs for renewable energy.

Technology	Installed costs, €/kW	Load factor, %	Generation cost €/MWh	
			5% tdr	8% tdr
Onshore wind	760-900	16-25	35-55	43-67
Offshore wind	1200	33-40	35-42	42-51
Solar PV	1400-3100	8-16	316-697	393-865
Solar thermal electric	1000-2000	21-30	35-54	58-68
Biomass gasification	2250	97	36	43
Wave/tidal stream	900-1500	30	28-47	43-72
Tidal barrage	1584	22	60 (1)	106

Note: 1. Assumes capital is repaid over 40 years, possibly feasible with a public sector project.

Generation costs for hydro, geothermal, biomass and tidal barrages are unlikely to change appreciably by 2020. Although plant costs for hydro and geothermal may fall slightly, this is likely to be offset by the higher costs of exploiting lower quality resources. It is difficult to project future generation costs for biomass since there is such a wide range of options and generating costs are critically dependent on agricultural and other subsidies.

For the technologies where substantial decreases in generation costs are anticipated, Table 4.4 summarises generation cost estimates for 2020, drawing on the sources cited in the text or in the table.

Integration issues

Wind, wave and solar energy are variable, and generally unpredictable. Both forms of tidal energy are variable, but predictable, and the other renewable energy sources are steady. However, the impacts of variability are quite modest. It must be remembered that the output from all generation sources is intermittent, rather than variable, as power stations are frequently disconnected from the network due to mechanical, electrical or instrumentation faults. Moreover, consumer demands are not totally predictable and so all power system operators carry reserves that enable them to deal with mismatches between demand and supply. When systems operate with significant quantities of unpredictable renewables what matters is the additional uncertainty, as this influences the scheduling of additional reserves and hence the costs.

Numerous worldwide studies have quantified the additional costs of this reserve, which is generally around €4/MWh for wind generation, when the wind contribution to electricity supplies is 20%. A comprehensive review of all the relevant issues has recently been published by the International Energy Agency¹⁵⁷.

Conclusions

Hydro electricity and wind energy are expected to deliver the biggest increases in electricity production by 2020 – roughly 2000 TWh in each case, depending on the growth rate in wind. Each of these technologies is expected to deliver electricity at around €40-50/MWh, which is likely to be competitive with nuclear, gas and coal – although this depends on the price of carbon by that time. The prospects for solar thermal electric, wave and tidal stream energy are more uncertain but their generation costs may also be competitive with the fossil fuel sources. Although the generation costs for solar photovoltaics appear high, there is enormous world wide potential, particularly for household and off-grid applications where other sources of electricity supply are likely to be expensive. The downward trend in costs for wind energy and photovoltaics has halted recently but is expected to resume, due to a combination of improved production techniques, larger installations and the impacts of research and development. The slowdown in cost reduction, in each case, has been partly due to increased commodity prices but it should be noted that further increases in these would also affect the costs of nuclear power as this is, similarly, very capital-intensive.

Annex A -

Exporting reactors

Civilian nuclear reactors generate electricity in 31 countries around the world. Of these, eight have become technology exporters. These are all members of the G8, (Canada, France, Germany, Japan, Russia, UK and USA), plus China. The only non-exporting G8 member is Italy, which phased out nuclear power following a referendum in 1987. The UK no longer has a commercial reactor design and manufacture capability, while France and Germany have effectively merged theirs through the creation of Areva. Japan has yet to win an export order for a reactor although it is becoming increasingly active in bidding contests. In two other countries a domestic industry has now been developed, India and the Republic of Korea.

In all other countries significant technology import would be required to construct further nuclear reactors.

In recent years the major nuclear vendors have merged or created strategic alliances, which has significantly reduced the range of separate companies or consortia now offering nuclear reactors.

Mergers of reactor vendors

Areva NP-Mitsubishi: Areva was formed by the merger of Framatome and the Siemens nuclear power division in 2001. In October 2006 Areva and Mitsubishi Heavy Industries announced a strategic partnership to develop a new generation of nuclear power plants.

Westinghouse-Toshiba: Westinghouse was sold to BNFL in 1998. During this ownership period the ABB nuclear division (which had already taken over the Combustion Engineering nuclear capability) was brought by BNFL for \$485m (€369m) in 2000. In February 2006 Toshiba won the takeover battle to purchase the Westinghouse nuclear division (including the ABB nuclear division) for \$5.4bn (€4.1bn).

GE-Hitachi: Hitachi has, for many decades licensed nuclear technology from GE. In November 2006, GE and Hitachi announced the intention to create a global alliance. Hitachi and General Electric will hive off their nuclear power operations into two joint ventures that will build, maintain and develop nuclear plants, with a final deal expected in early 2007. Hitachi will own 40% of the US venture and at least 80% of the Japanese venture, with the rest going to its American partner.

Atomic Energy Canada Limited: AECL was founded in 1952 and remains a Crown Corporation. It currently has partnership agreements with a number of companies, including: Babcock and Wilcox, Bechtel, China National Nuclear Corporation, General Electric Nuclear Products (Canada), Hitachi, Siemens Canada and SNC Lavalin

China National Nuclear Corporation: While China is continuing to import, or at least offer tenders for the construction of nuclear power plants, it is also increasingly constructing its own nuclear reactors and fuel cycle facilities, through the China National Nuclear Corporation.

Atomstroyexport: The Russian, formerly Soviet, nuclear power industry has been responsible for the export of reactors across the world. Most were deployed in Europe, but others were sold to China, India and Iran (in service or under construction) and to Cuba and Libya (not completed). The main construction firm is Atommash, with the export of equipment being undertaken by Atomstroyexport.

Nuclear Power Corporation of India Ltd (NPCIL): responsible for design, construction, commissioning and operation of thermal nuclear power plants.

Korea Power Engineering Company (KOEPEC): involved in the construction of nuclear power plants, both with strategic partners e.g. AECL and as main contractor.

Nuclear power and international financial institutions

Despite the significant number of nuclear exports, to date the international financial institutions (IFIs) have not funded nuclear power development to any great extent.

European Bank for Reconstruction and Development (EBRD)

The EBRD is the only IFI that has a specific remit to lend for nuclear power projects. In 2006 the Bank relaxed its rules on lending for nuclear projects. Previously, the Bank would only lend for the completion or upgrading of nuclear power projects on the condition that 'they are directly linked with the closure of high-risk reactors operating in the country concerned'. However, this linkage requirement has been removed and now the major requirements for the Bank's involvement are¹⁵⁸:

- the Bank will not consider providing financing to new reactors;
- it will provide financing to an operating facility in relation to nuclear safety improvement;
- the safe and secure management of radioactive waste and spent fuel;
- nuclear projects will have to meet the same least-cost criteria (including the review of supply and demand-side energy alternatives) as non-nuclear projects.

The EBRD has assessed three projects: the completion of the Mochovce 1 and 2 units in Slovakia (1995); the completion of Khmelnytsky 2 and Rovno 4 (K2R4) in Ukraine (2000) and a post completion upgrading project of the K2R4 project (2004).

However, the Bank has only ever given one loan, €50m for the second K2R4 project.

World Bank

In 1998 on its web site, The World Bank stated that 'The Bank has never financed a nuclear power station'. In 2006, it expanded on this policy:

Q. Will the Bank fund nuclear energy and, if not, why not?

A. The Bank has never financed a nuclear power station. Nuclear power produces no particulates, sulphur, or greenhouse gas emissions and thus appears to offer a clean, non-fossil-fuel alternative for power generation. However, world experiences with high investment costs, time-consuming and costly approval processes, lack of sustainable waste disposal options, risks of major accidents - together with the Chernobyl disaster - have raised grave doubts about the future viability of nuclear power. Private investors shy away from such risky high-cost investments.

Financing for nuclear development is usually available from suppliers' credits and export financing agencies.

Q. Given its work on shadow prices of carbon, at what price does the Bank believe that nuclear energy is warranted in the fight against global warming?

A. The issues surrounding nuclear power go beyond economic costs alone. Nuclear energy is not acceptable in many parts of the world because of concerns over reactor safety, disposition of nuclear wastes and proliferation of fissile materials. The trade-offs are thus complex and cannot be boiled down to a single carbon shadow value.

In its Environment Assessment Sourcebook it makes the following comments on nuclear power¹⁵⁹.

- The Bank takes the position that, as the financier of last resort, it is unnecessary for its funds to be used for this purpose.
- Given the limited number of suppliers, procurement on the basis of International Competitive Bidding is not possible.
- Cost of nuclear projects typically come in at two to three times the original estimates, delays have been substantial, and production problems have resulted in output well below capacity.
- The economic case is clear: under present cost structures, the Bank would not finance new plants because they are uneconomic. In the unlikely event that nuclear plants become economic, the Bank would not finance them because there are other sources of funds available and, as financier of last resort, Bank funds are not required.

Asian Development Bank (ADB)

The ADB is clear in its view that it should not fund nuclear power. In its 1995 energy policy it states:

*Continued use of nuclear power in developed and developing countries and its further expansion require not only firm assurances that technical and institutional measures will be effective in protecting public health and safety, but also sustained public confidence and broad political support. The technical complexity of nuclear power technology is a barrier to public understanding, which makes it difficult for members of the public to evaluate safety questions for themselves. The Bank is very much aware of this background and has not been involved in the financing of nuclear power generation projects in the DMCs [Developing Member Countries] due to a number of concerns. These concerns include issues related to transfer of nuclear technology, procurement limitations, proliferation risks, fuel availability and procurement constraints, and environmental and safety aspects. The Bank will maintain its policy of non-involvement in the financing of nuclear power generation.*¹⁶⁰

Other IFIs or regional development banks do not mention nuclear power within their energy policy and have not to date provided finance for commercial nuclear power plants. This includes:

- European Investment Bank;
- InterAmerican Development Bank; and
- African Development Bank

Export credit agencies

The controversy around nuclear power has tended to reduce the involvement of IFIs in the funding of nuclear power. To compensate for this, governmental export credit agencies (ECAs) have provided guarantees for a large number of nuclear projects, for example, it is suggested that the US Export-Import Bank has granted financial assistance of over \$8bn (€6.1bn) of nuclear projects since the 1960s. Table A1.1 indicates recent ECA involvement in nuclear power projects throughout the world.

Table A1.1: ECA financing of nuclear power

Exporting Country	Recipient Country	Project
Canada	China	Quinshan III
	Romania	Cernavoda I and II
France	China	Ling Ao 1 and 2
	Finland	Olkiluoto
Germany	China	Lianyungang
Italy	Romania	Cernavoda II
Japan	China	Quinshan II and III
	Mexico	Laguna Verdi
Russia	China	Lianyungang
	India	Kudankulam
	Iran	Bushar
UK	China	Quinshan II
		Ling Ao
US	Bulgaria	Kozloduy 5 and 6
	China	Quinshan II and III
	Czech Republic	Temelin 1 and 2

Source: Financing Disaster¹⁶¹

The most recent is that of the Olkiluoto project in Finland, where controversially French and Swedish ECA guarantees were involved in a project within the European Union. This arrangement is now the subject of the European Commission State Aid complaint and formal investigation.

The involvement of the ECAs is said by one of the parties making a formal complaint, the European Renewable Energy Federation, to have enabled the project to access cheaper financing. Such a mechanism has been put forward by the International Energy Agency in its World Energy Outlook, when it notes a number of policies that might be introduced to enable increased nuclear power generation, including 'loan guarantees to reduce the cost of capital.'¹⁶²

Annex B -

Funding long-term liabilities

Introduction

Most people assume that the cost of decommissioning retired nuclear plants and dealing with the waste will have a significant impact on the cost of power from a nuclear power station. They assume that the 'polluter should pay', meaning that consumers should be required to make payments so that a sufficient sum of money is available to the future generation that ends up having to do the job. However, as explained in Part 2, these operations are expected to take place many decades in the future, perhaps more than a century after plant start-up or after the spent fuel has been removed from the reactor. This means that in most economic analyses, where future costs and benefits are 'discounted' to bring them to a comparable base, such costs are very small.

The basic premise of discounting is reasonable. A bill of €1 that must be paid today should weigh more heavily in financial analyses than a bill of €1 that must be paid in a year's time. If money can be invested to earn, say, a real interest rate of 5%, a sum of about 95c can be invested today and will have grown sufficiently after 1 year to pay the bill. In this case, the discounted value of the €1 liability would be 95c and the discount rate, 5%.

The introduction of competition to the electricity industry has dramatically increased the discount rate applied to power station projects of all types and 15% is now a minimum rate for a plant exposed to a competitive environment. If this rate was applied to the long-term liabilities, they would 'disappear' from the calculations. A liability of €1bn (the order of magnitude of the sum of money that might be needed to decommission a nuclear power plant) would, in a 'discounted cash flow calculation' reduce to a discounted value of only €1m after discounting for 50 years. However, it would be wrong to apply this rate to liabilities of this type.

There is a moral imperative for the 'polluters' to take all reasonable measures to ensure that those that have to perform the clean-up are given sufficient money to do the job. This imperative has three main dimensions:

- Estimates of the expected cost should be conservative or pessimistic, especially where the cost is not well established so that funds are not inadequate because the cost is greater than expected;
- Funds collected from consumers should be placed in very low risk investments to minimise the risk that the funds will be lost. Such investments inevitably yield a low interest rate;
- Funds should not be accessible by the company that owns the plant other than for decommissioning purposes.

Experience from the UK

The experience of the UK in dealing with long-term liabilities

is salutary, with costs consistently under-estimated and provisions not adequately safeguarded.

As a result, Britain has ended up with liabilities estimated in 2006 at about £75bn (€112bn) but rising fast, resulting from the decommissioning needs of the civil nuclear power programme and no more than a few hundred million pounds in real funds to pay for this. On present plans, these liabilities will be paid for by tax-payers of the day as the work is carried out over the next 140 years.

The Nuclear Decommissioning Authority (NDA) owns all these sites except the eight, more modern nuclear power plants owned by British Energy. If we look at the liabilities in more detail, about £43bn (€65bn) is accounted for by the non-reactor sites previously owned by the nationally-owned British Nuclear Fuels (BNFL), nearly £40bn (€60bn) alone for Sellafield. Another £5bn (€7.5bn) is accounted for by sites previously owned by United Kingdom Atomic Energy Authority (UKAEA, also nationally owned), nearly £3bn (€4.5bn) of which is for the Dounreay site. The Magnox power stations account for about £13bn (€20bn), British Energy's plants for about £8.6bn (€13bn) and a further £7bn (€11bn) represent some additional costs that the NDA has identified that will be incurred for 'more LLW [low-level waste] than can fit into the LLW repository near Drigg and the larger amounts of contaminated land than had been originally anticipated.' The British Energy liabilities for decommissioning alone increased by 65% between 2005 and 2006.

However, if we focus on the £20bn (€30bn) needed for the commercial civil nuclear power plants we find a sorry story of failure to safeguard consumer provisions.

Up to 1990

Up to 1990, the previous nationalised owners of the nuclear plants (Central Electricity Generating Board (CEGB) and South Scotland Electricity Board (SSEB) for the three Scottish stations) had collected provisions valued at £3.8bn (€5.7bn). These existed only as accounting provisions, effectively the assets of the companies. However, when the electricity industry was privatised (for only about a third of its asset value), the temptation for the government to keep all the revenue was too much. Instead of passing the provisions on to the new owners, Nuclear Electric and Scottish Nuclear, the Treasury kept all the privatisation proceeds. Because the nuclear plants were then unsaleable, Nuclear Electric and Scottish Nuclear remained in public ownership.

1990-96

Nuclear Electric was expected not to be able to cover its costs and meet its liabilities, so to allow it to continue to trade, the government introduced a consumer subsidy, the Fossil Fuel Levy (FFL), payable to Nuclear Electric (Scottish Nuclear was

subsidised under different arrangements). The FFL raised about £1bn (€1.5bn) per year. The then Minister of Trade and Industry, Michael Heseltine, told Parliament in 1992 it was 'to pay for the decommissioning of old and unsafe stations'. This was inaccurate and the Energy Minister in 1990 described it accurately when he said it was to keep Nuclear Electric 'cash positive'. There were no restrictions on how Nuclear Electric could spend the money and it used the money as additional cash flow. A small amount was spent on decommissioning, nearly half was unspent, but the rest was spent by Nuclear Electric meeting its immediate costs. Nuclear Electric was effectively bankrupt and its marginal spending was building the Sizewell B PWR, which it did without recourse to borrowing. Given that the FFL was marginal additional income to Nuclear Electric, it must be concluded that up to £3bn (€4.5bn) of the subsidy was spent on Sizewell B, completed in 1995 at a cost of over £3bn (€4.5bn).

One year later in 1996, the more modern nuclear plants, the seven AGR stations and Sizewell B were privatised in a new company, British Energy, for about £1.7bn (€2.5bn). The sale price was probably less than a tenth of the replacement cost of these eight stations. Despite the fact British Energy was effectively given its plants, it still collapsed financially in 2002 and had to be rescued by the UK Government at a cost to future taxpayers, estimated then to be in excess of £10bn (€15bn). The older plants remained in public ownership in a new, publicly-owned company, Magnox Electric.

British Energy 1996-2005

The British Government required a segregated fund to be set up to pay for British Energy's decommissioning requirements using £227m (€340m) of the unspent FFL to launch it. However, it was clear that if the fund had had to cover all the decommissioning liabilities, the Government would have had to pay the buyers to take the company. The little-publicised fix was to require that the segregated fund pay only for stages 2 and 3 of decommissioning with stage 1 paid for from company cash flow. Stage 1 is essentially removal of the fuel and is a technically simple stage entailing continuing activities that have been carried out throughout the life of the plant. Because completion of Stage 1 allows the work-force to be sacked (the plant is no longer a criticality risk), it is usually carried out as quickly as possible, provided there is somewhere to put the fuel. The cost of stage 1 is about 10% of the total cost of decommissioning. Stage 2 is also relatively routine requiring the clearance of uncontaminated or very lightly contaminated buildings. It might account for about 30% of the undiscounted cost. The economic incentive is to delay this as long as possible to allow provisions longer to earn interest, so fewer provisions are needed to meet a given liability.

Stage 3 is much the most expensive and challenging part, involving the cutting up and disposal of the contaminated parts, requiring strict worker protection from exposure and generating

large amounts of radioactive waste. It might account for about 60% of the liability.

If we assume stage 1 is carried out immediately, stage 2 after, say, 40 years and stage 3 after 70 years, and we assume funds earn a real rate of return of 3.5%, the picture for relative discounted costs is very different. Stage 1 accounts for 43% of the discounted cost, stage 2 for 33% and stage 3 for 23%. The overall discounted cost is less than a quarter of the undiscounted cost and the discounted cost of stage 3 is less than 10% of the undiscounted cost. This 'fix' allowed British Energy to contribute about £18m (€27bn) a year to a fund that had to deal with a liability (including stage 1) then estimated to be about £5bn (€7.5bn).

The assumption that British Energy would have enough cash flow to pay for anything was proved wrong in 2002 when the company collapsed. In fact, the trustees (the Nuclear Trust) of the decommissioning fund, the Nuclear Generation Decommissioning Fund (NDF), appear to have precipitated the collapse of British Energy by serving a default notice relating to the solvency of British Energy because it was unable to pay even the small sum required for the NDF. British Energy was rescued using taxpayers' money and re-launched in January, 2005. In the last British Energy annual report (2003/04) before its re-launch, the value of the NDF was reported to be £440m (€660m).

BNFL 1996-2005

Most of the unspent proceeds of the FFL (about £2.7bn or €4bn) were passed to the new owners of the Magnox stations, Magnox Electric. This was because the Magnox stations are expensive to decommission and were near retirement so the need for funds was more urgent than for the British Energy stations. In 1998, Magnox Electric became a division of BNFL. The unspent proceeds were separately identified in BNFL's accounts as the Nuclear Liabilities Investment Portfolio (NLIP) and were invested in a way intended to ensure they would not lose value. By 2004, with additions from BNFL and interest, the fund had grown to a little over £4bn (€6bn). However, the fund was an internal one, not rigorously separated from BNFL's business. In addition, BNFL was in increasingly deep financial trouble because it could not cover its liabilities and was allowed to continue to trade only through government assurances (the Secretary of State's Undertaking).

The Government finally lost patience with BNFL in 2003 and decided to take away all BNFL's sites and give them to the NDA, leaving two main operating divisions, Westinghouse (sold to Toshiba in 2006) and BNG (expected to be privatised in 2007). BNG has to compete to operate the facilities previously owned by BNFL. The Treasury quietly absorbed the NLIP into its other income, effectively leaving an IOU. This is an empty gesture because the state would be obliged to pay for decommissioning in any case if no other funds existed.

Table A2.1: Timing of British Energy liabilities

	2004	2004	2004	2005	2005	2005	2006	2006	2006
	Decom	Fuel not contracted	Contracted fuel costs	Decom	Fuel not contracted	Contracted fuel costs	Decom	Fuel not contracted	Contracted fuel costs
< 6 years	126	43	1340	-	54	934	21	6	956
6-10 years	206	123	1181	340	99	920	666	16	915
11-25 years	320	422	1575	591	338	1139	2244	136	1002
26-50 years	54	1079	649	473	1093	-	1271	350	-
> 50 years	-	3060	485	3777	2061	-	4376	2042	-
Total not discounted	5.1	4.7	5.2	5.2	3.6	3.0	8.6	2.5	2.9
Total discounted	1.1	1.1	3.5	1.1	0.9	2.3	2.7	0.5	2.2

Source: British Energy Annual Report and Accounts

Note: Liabilities are discounted at a rate of 3%

NDA 2005 onwards

The NDA now has no guaranteed access to funds. It must compete for all other calls on the Treasury for its funds. When the NDA was set up, there was a lot of discussion about measures that would guarantee its income such as segregated funds and funding on a 10-year basis. But in the end, the heavy hand of the Treasury was felt, no segregated fund was set up and its funding was committed only three years forward.

The NDA has ambitious and admirable plans to reduce the timescale for completion of Magnox decommissioning from over 100 years after plant closure to completion in only 25 years. This will have huge implications for public spending. Jobs that are currently expected to be postponed effectively indefinitely will now require major public spending within the next decade as decommissioning of the Magnox plants already retired (some more than 15 years ago) is completed. All things being equal, the undiscounted cost of stage 3 would increase significantly because there would be much more waste to dispose of and, for example, jobs that could be done by a human 60 years after plant closure, might need to be done by a robot. It remains to be seen whether the Treasury will allow this. On the evidence of the way in which funding for the NDA was dealt with, it seems unlikely.

The NLF 2005 onwards

When British Energy was re-launched, the NDF became the Nuclear Liabilities Fund (NLF) and is now required to pay for 'qualifying uncontracted nuclear liabilities' as well as 'qualifying decommissioning costs'. The former is essentially the cost of dealing with spent fuel from Sizewell B, while the latter is presumably stage 2 and stage 3 decommissioning costs. In addition to the £440m (€660m) that was in the NDF in 2004, British Energy issued £275m (€412m) in New Bonds to the NLF on its re-launch.

Income to the NLF is expected to come from three sources.

British Energy will put in a flat amount of £20m (€30m) per year (indexed to inflation but tapering off as the stations are closed) and £150,000 (€225,000) for every tonne of uranium in the fuel loaded into Sizewell B. However, the most important contribution is a 'cash sweep'. Under this, the Government is entitled to take 65% of British Energy's net cash flow which it must place in the NLF.

Some interesting changes took place in the reporting of liabilities between 2004 and 2006 (see Table A2.1). The 2004 report for decommissioning presumably shows only the timing of stage 1 operations because this is what British Energy was liable for. The fact that no decommissioning expenditure is expected within 5 years in the 2005 report presumably reflects the life extension for the oldest units. The 2005 report confirms that a high proportion of the money for decommissioning will be spent after year 50 implying that decommissioning will probably not be completed until more than 50 years after plant closure.

The very large reduction in contracted fuel costs must reflect the new contracts with BNFL that came into force when the restructuring of British Energy became effective. It is not clear how this new contract could reduce the uncontracted liabilities by nearly a quarter.

However, the most remarkable change is the increase in decommissioning liability from £5.2bn (€7.8bn) to £8.6bn (€12.9bn). This remarkable increase followed the completion of a 'quinquennial' review of the liabilities required by the safety and environmental regulatory authorities.

On the face of it, using the fund to also pay for the uncontracted liabilities seems reasonable. However, is there another explanation? If stage 2 of decommissioning is delayed after plant closure, it would be many years before the NDF could be accessed. Perhaps, the Treasury is hoping that the NLF can be accessed much earlier to pay for some of Sizewell's fuel disposal (uncontracted fuel costs), which arise immediately, delaying the time when taxpayers' money will be required for that purpose.

British Energy 2005 onwards

The entitlement under the 'cash sweep' is the most significant change under the new arrangements and is expected to be the main source of income to the NLF. This entitlement can be converted into shares (1,042 million additional shares) and sold. Since the Government owns 65% of the company's profits, the value of these shares would be equivalent to 65% of the company. This percentage is a maximum and could fall. In May 2006, British Energy was trading at about £6.30 (€9.50), and the cash sweep was expected to yield about £3bn (€4.5bn) if converted into shares.

One very important point that needs to be made is that the NLF is set up in totally the opposite way to other decommissioning funds. Decommissioning funds should be designed to try to minimise the dependence of the fund on the performance of the company so the money will be there regardless of the fortunes of the company. For the NLF, the funds will only be adequate if the company prospers.

In theory, the NLF was in surplus in February 2006. However, this surplus is based on a number of very powerful assumptions. First, it must be assumed that the estimated discounted decommissioning cost is accurate. The NDA has a supervisory role over British Energy's plans for decommissioning, 'reviewing and approving BE's strategies and budgets for decommissioning its power plants and discharging its uncontracted liabilities'. If the NDA decides British Energy should also aim to complete decommissioning within 25 years instead of the 50-60 years assumed by British Energy, the undiscounted cost of stage 3 would increase significantly because there would be more waste to dispose of and the discounted cost of stage 3 would increase by about 150%.

Second, it assumes the current British Energy share price is an accurate representation of the long-term value of the company. If we go back to the original British Energy launched in 1996 with a share price of about £2.40, the share price tripled in the first three years only to collapse completely in 2002 to only a few pence. British Energy was re-launched in January 2005 at £2.63 so, as previously, the company has initially done well. However, it is not difficult to think of circumstances that could lead to another collapse. Indeed, by autumn 2006, problems with the AGRs meant that British Energy had to warn shareholders that its income would be down in 2006/07 knocking a quarter off the share price.

The current tight gas market in Britain could also easily become over-supplied with new LNG facilities coming on-line and gas producers anxious to take advantage of the high prices in the UK. This could lead to yet another 'dash for gas' producing surplus capacity and another collapse in wholesale electricity prices. In these circumstances, the 'cash sweep' would quickly become worthless if British Energy's profits disappear and British Energy collapses. Given these uncertainties, it is difficult to see how the Government could now proceed, in good faith, with a sale of its share entitlement.

Third, it assumes that any proceeds of a share sale are paid into the NLF. The NAO report states: 'if the Department decides to convert and sell all or part of the cash sweep, British Energy will

issue a number of shares to the Nuclear Liabilities Fund.' On the past record, can there be any confidence that the Treasury will not judge that it can use the proceeds of any such sale to better effect by diverting it to other public spending priorities?

A better way to manage decommissioning funds

If we take the polluter pays principle as our guiding principle, as enshrined in the EU's justification for allowing the establishment of the NDA, the objective of decommissioning provisions is clear. It should be to provide maximum assurance that those who have to decommission our nuclear plants have access to sufficient money to do the job to appropriate standards whenever they choose to do it. It is the future generation that will have to carry out this potentially hazardous job. It is also they who will best be able to judge, on the basis of factors such as changes at the site (eg, rising sea levels), availability of skills and availability of facilities to take the waste, whether to decommission then or delay.

The first obvious requirement is that the provisions be placed in a segregated fund that will not be lost if the company fails. There is also an equally strong case for a segregated fund to pay for spent fuel disposal, although this should probably be separate from the decommissioning fund. Provisions should be invested in very low risk investments equivalent to the risk level of government bonds (which pay a commensurately low rate of return) to minimise the risk of being lost.

The plant owner should make financial arrangements so that the full cost of decommissioning will be available from the day the plant starts operation. This is to cover the risk that, for whatever reason, accident, corporate failure of the owner, unprofitability of the plant, the plant is closed well before the end of its forecast lifetime. This does not necessarily require that the entire funds be deposited in a segregated fund the day the plant enters service. Financial tools such as insurance or bonds, may be a cheaper but equally effective way to meet this requirement.

The fund should cover all stages of decommissioning and the liability should be estimated extremely conservatively. Many of the costs, such as cutting up contaminated structures, can only be guesses because these activities are unproven on this scale and costs such as waste disposal are rising rapidly with no clear end in sight. The UK's Magnox stations were estimated to cost about £250m (€375m) each to decommission in 1989, but by 2005, this figure had risen to well in excess of £1bn (€1.5bn). As a result, contingency allowances should be very high.

Decommissioning costs should be estimated assuming prompt decommissioning. It is not for the current generation to dictate when future generations should get rid of the facility we are burdening them with. Presuming prompt decommissioning also avoids the need to make a heroic assumption that funds will be able to earn a positive rate of interest long into the future.

Annex C -

Energy [R]evolution: A Sustainable World Energy Outlook.

Energy efficiency in the energy [r]evolution Scenario

The report: 'Energy [R]evolution: A sustainable World Energy Outlook', produced by the European Renewable Energy Council (EREC) and Greenpeace International, provides a practical blueprint for how to cut global CO2 emissions by almost 50% within the next 43 years, whilst providing a secure and affordable energy supply and, critically, maintaining steady worldwide economic development. Notably, the plan takes into account rapid economic growth areas such as China, India and Africa, and highlights the economic advantages of the energy revolution scenario. It concludes that renewable energies will represent the backbone of the world's economy – not only in OECD countries, but also in developing countries such as China, India and Brazil. "Renewable Energy will deliver nearly 70% of global electricity supply and 65% of global heat supply by 2050."

A range of options has been considered in the energy [r]evolution scenario for reducing the demand for energy in the period up to 2050. The analysis focuses on best practice technologies. The scenario assumes continuous innovation in the field of energy efficiency, so that best practice technologies keep improving.

Industry

Approximately 65% of electricity consumption by industry is used to drive electric motor systems. This can be reduced by employing variable speed drives, high efficiency motors and using efficient pumps, compressors and fans. The savings potential is up to 40%. The production of primary aluminium from alumina (which is made out of bauxite) is a very energy-intensive process. It is produced by passing a direct current through a bath with alumina dissolved in a molten cryolite electrode. Another option is to produce aluminium out of recycled scrap. This is called secondary production. Secondary aluminium uses only 5 to 10% of the energy demand for primary production because it involves remelting the metal instead of an electrochemical reduction process. If recycling increases from 22% of aluminium production in 2005 to 60% in 2050 this would save 45% of current electricity use.

Transport

Use of hybrid vehicles (electric/combustion) and other efficiency measures could reduce energy consumption in passenger cars by up to 80% in 2050.

Households / services

Energy use by household appliances such as washing machines, dishwashers, TVs and refrigerators can be reduced by 30% using the best available options and by 80% with advanced technologies. Energy use by office appliances can be reduced by 50-75% through a combination of power management and energy efficient computer systems.

Use of stand-by mode for appliances is on average responsible for 5- 13% of electricity use by households in OECD countries. Replacement of existing appliances by those with the lowest losses would reduce standby power consumption by 70%.

Electricity Generation

The development of the electricity supply sector is characterised by a dynamically growing renewable energy market and an increasing share of renewable electricity. According to 'Energy [R]evolution: A sustainable World Energy Outlook', produced by the European Renewable Energy Council (EREC) and Greenpeace International renewable energy sources could compensate for the phasing out of nuclear energy and reduce the number of fossil fuel-fired power plants required for grid stabilisation. By 2050, 70% of the electricity produced worldwide could come from renewable energy sources. 'New' renewables – mainly wind, solar thermal energy and PV – could contribute 42% of electricity generation. The following strategy paves the way for a future renewable energy supply:

- The phasing out of nuclear energy and rising electricity demand will be met initially by bringing into operation new highly efficient gas fired combined-cycle power plants, plus an increasing capacity of wind turbines and biomass. In the long term, wind will be the most important single source of electricity generation.
- Solar energy, hydro and biomass will make substantial contributions to electricity generation. In particular, as non-fluctuating renewable energy sources, hydro and solar thermal, combined with efficient heat storage, are important elements in the overall generation mix.
- The installed capacity of renewable energy technologies will grow from the current 800 GW to 7,100 GW in 2050. Increasing renewable capacity by a factor of nine within the next 43 years requires political support and well-designed policy instruments, however. There will be a considerable demand for investment in new production capacity over the next 20 years. As investment cycles in the power sector are long, decisions on restructuring the world's energy supply system need to be taken now. To achieve an economically attractive growth in renewable energy sources, a balanced and timely mobilisation of all technologies is of great importance. This mobilisation depends on technical potentials, cost reduction and technological maturity. Figure 22 shows the comparative evolution of the different renewable technologies over time. Up to 2020, hydro-power and wind will remain the main contributors to the growing market share. After 2020, the continuing growth of wind will be complemented by electricity from biomass, photovoltaics and solar thermal (CSP) energy

For more information on the Energy [R]evolution, please visit: www.greenpeace.org/energyrevolution

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