Agenda, Volume 13, Number 3, 2006, pages xxx-xxx

Nuclear Power for Australia?

Anthony Owen

In 2005 there were rising expectations for nuclear power. High rates of economic growth and energy demand, particularly from China and India, combined with environmental constraints, energy security concerns, and on-going energy poverty in the developing world raised the possibility of a nuclear revival.

Worldwide there were 441 nuclear power plants operating at the end of 2005, totalling 368 GWe of generating capacity, and supplying about 16 per cent of the world's electricity. This latter figure has remained relatively stable over the past two decades, indicating that nuclear power has grown at about the same rate as total global electricity production over the period.

Current expansion, as well as perceived near-term and long-term growth prospects, is centred on Asia. Thomas (2005) reports that China, France, Korea and Japan have all announced possible orders over the next two years, although approval processes in France and Japan are likely to push back the scheduled dates of construction. Twenty four of the last 34 reactors to have been connected to the grid were in Asia.

At year-end 2005 there were 27 reactors described as being 'under construction' worldwide — although construction has effectively ceased on three of them, and for a further three construction started before 1990 and there must be doubts about whether these plants will ever be completed. Of those still under construction, 17 are based upon Indian, Russian, or Chinese technology, designs that would be highly unlikely to be adopted in OECD countries due to the rigours of the licensing processes required, and Western reactor manufacturers still face a dearth of new orders particularly from Europe and the United States.

Sixteen of the reactors under construction are in Asia and just one is in an Organisation for Economic Cooperation and Development (OECD) country (Finland). The Olkiluoto reactor in Finland is widely regarded as a special case. It is not being built for an electricity utility but rather for a consortium of industries who will guarantee to take all power on a 'not-for-profit' basis. It will not therefore compete in the Nordic electricity market. Construction costs are reported to be €3.2 billion (€2000/kW), with finance being provided by the Bayerische Landesbank (€1.95 billion) at a nominal interest rate of 2.6 per cent, and loan guarantees of €720 million from the French and Swedish export credit guarantee agencies. The European Commission is currently considering complaints that the plant has received illegal state subsidies. Whether or not these costs can be achieved (or repeated) is an unknown factor. The project is currently running nine months behind schedule.

Tony Owen is Associate Professor in the School of Economics at the University of New South Wales and a past President of the International Association for Energy Economics.

In its 2006 Annual Energy Outlook, the US Energy Information Administration (EIA) projected increased US installed nuclear capacity from 99.6 GW in 2004 to 108.8 GW in 2030. The increase comprised 6.0 GW of capacity at new plants stimulated by the 2005 Energy Act (EPACT2005) tax incentives and 3.2 GW of capacity expansion at existing plants. EPACT2005 provides an 8-year production tax credit of $18 per MWh for up to 6GW of capacity built before 2021, limited to $125 million per 1000-MW per year. If the capacity is reached before 2020, the credit program ends, and no additional units are expected. The increase in capacity at existing units assumes that all additions approved, pending, or expected by the Nuclear Regulatory Commission will be carried out. Other incentives offered to the nuclear industry in EPACT2005 were loan guarantees for up to 80 per cent of project cost (valid for all Greenhouse Gas (GHG)-free technologies), insurance protection against delays during construction and until commercial operation caused by factors beyond the private sector's control, limitation of liability resulting from an accident, all decommissioning trust funds to qualify for tax deductibility, and the authorisation of a $2.95 billion R&D portfolio. Several companies have started the licensing process for new plants, but firm orders have yet to be made and even under a 'best case' scenario the first new plant would not come online until around 2015 at an existing site.

Even with this expansion of nuclear capacity, if it actually occurs, nuclear power's current 20 percent share of total US generation is expected to decline to 15 percent by 2030. The EIA expects fifty percent of all new generating capacity additions to 2030 to be coal in the absence of any carbon price being imposed on combustion of that fuel.

In summary, this is not a portrait of an industry in revival. Although the political will to expand nuclear capacity appears to be present in many OECD countries, as will be discussed below electric utilities do not appear to be in comfortable support.

Nuclear Power in Australia

Currently, Australia has no commercially operating or planned nuclear power reactors and, as a nation well endowed with low-cost reserves of coal, this position would have been unlikely to change in the foreseeable future were it not for the threat of an impending global environmental crisis arising from the combustion of fossil fuels and a government commitment to a solution based upon a 'technology fix' through its international Climate Action Partnerships.

However, this has not always been the case. Following the report of a feasibility study, in October 1969 the then Prime Minister (Gorton) announced that the Commonwealth government would construct a 500 MWe nuclear power station on Commonwealth land at Jervis Bay on the south coast of New South Wales. Tenders were obtained, and site preparation and environmental studies were undertaken by the Australian Atomic Energy Commission (AAEC). This was viewed as just the beginning of a substantial commitment by Australia to nuclear power. At the Australian and New Zealand Association for the

Advancement of Science conference in May 1971, the Chairman of the AAEC, Sir Phillip Baxter, was quoted as stating that Australia's nuclear power capacity would reach 22.5 GWe by 1995, and 36 GWe by the year 2000, or 27.2 and 32.8 per cent respectively of projected total installed electricity capacity from all sources. (Both of these projections were way off beam. Installed electricity capacity from all sources was actually 37.7 GWe in 1995 and 46.6 GWe in the year 2000, whereas Baxter's projections implied capacity of 82.7 GWe and 110GWe respectively in those years.) Baxter's crystal ball was abruptly shattered just a few months later when the Jervis Bay project was deemed to be uneconomic and all construction plans deferred. Subsequently the project was abandoned and the prepared site now serves as a car park.

The Challenge of Climate Change

The ultimate objective of the 1992 United Nations Framework Convention on Climate Change (UNFCCC) was to stabilise greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous human interference with the climate system. However, it soon became evident that in order to meet this objective it would be necessary to establish a legal instrument that would provide a sound basis for long-term co-operative global action. Negotiations concluded in Kyoto in December 1997 with the release of the Kyoto Protocol. The Kyoto Protocol established a legally binding obligation on Annex I Parties (which comprise all OECD nations, with the exceptions of Turkey, Mexico and Korea, and the 'transition' market economies of Eastern Europe; a total of 38 countries) to reduce emissions of GHGs by an average of 5.2 per cent below 1990 levels by the years 2008-2012. The Protocol became legally binding when the required 55 countries (including developing countries) accounting for at least 55 per cent of total 1990 carbon dioxide emissions had ratified it. This occurred on 16 February 2005, when the Russian Federation ratified. Australia and the USA are the only Annex I countries yet to ratify the Protocol.

The severe challenge posed by the requirement to reduce emissions of GHGs, especially in the electricity generation sector, has led to renewed worldwide interest in nuclear power for base-load electricity production, stimulated by its relatively low life-cycle GHG emissions footprint compared with fossil fuel technologies. A longer-term possibility is the production of 'carbon free' hydrogen for use with fuel cells in the transport sector, thus relieving the sector of its current heavy reliance on hydrocarbons. However, the question of whether nuclear power is a financially viable option remains an issue distorted by the raft of assumptions required to assess its generation costs. The objective of this paper is to attempt to identify key parameters for determining the financial viability of nuclear power in Australia. This paper focuses on direct economic aspects of nuclear power, and largely ignores issues relating to public acceptability and nuclear waste disposal and plant decommissioning. To the extent that such issues cause delays in construction of nuclear plant or restriction of operations, clearly they will also have a direct economic impact on the viability of nuclear technology.

The Nuclear Fuel Cycle

A nuclear power plant is simply a very large and expensive device for generating electricity using the heat generated by nuclear fission, a physical reaction. This differs from fossil fuel power plants which generate heat by combustion, a chemical reaction. Thereafter, the remaining steps in the process of electricity generation are very similar. The heat is used to produce steam, which drives turbines that turn electric generators.

The manufacture of fuel for nuclear power plants and its processing and management subsequent to reactor discharge are referred to as the 'front end' and 'back end' of the nuclear fuel cycle. In between lies the irradiation – the period when the fuel is contained within the core of the reactor.

The total fuel cycle comprises a number of activities, the possible combinations of which provide the various fuel cycle options. These activities are:

- uranium mining and milling
- uranium refining and conversion to hexafluoride
- uranium enrichment
- fuel fabrication
- reactor operation
- spent fuel storage
- spent fuel reprocessing
- radioactive waste management
- decommissioning of nuclear facilities

In addition, the fuel cycle also incorporates the transportation of various materials within the above activities.

The vast majority of nuclear power reactors in operation today operate on what is known as a 'once-through fuel cycle'. Strictly speaking this is not a cycle since the unused part of the spent fuel is not recycled. The spent fuel is not reprocessed but is kept in temporary storage until it can be sent for permanent disposal by, for example, conditioning it and placing it underground in a deep geological repository.

Life Cycle Analysis of the Nuclear Fuel Cycle

When comparing the environmental footprints of alternative energy technologies, it is important that the power generation or combustion stage of the technology not be isolated from other stages of the 'cycle'. For example, a nuclear power reactor does not emit GHGs in its operation. However production of its 'fuel' (that involves the first four dot points above) may involve significant quantities of GHG emissions. To avoid such distortions, the concept of life cycle analysis (LCA) has been developed.

LCA is based upon a comprehensive accounting of all energy and material flows, from 'cradle to grave', associated with a system or process. The approach has typically been used to compare the environmental impacts associated with different products that perform similar functions, such as plastic and glass bottles. In the context of an energy product, process, or service, a LCA would analyse the site-specific environmental impact of fuel extraction, transportation and preparation of fuels and other inputs, plant construction, plant operation, waste disposal, and plant decommissioning. Thus it encompasses all segments including upstream and downstream processes and consequently permits an overall comparison (in a cost benefit analysis framework) of short- and long-term environmental implications of alternative energy technologies. Central to this assessment is the valuation of environmental externalities of current and prospective fuel and energy technology cycles. It should be noted, however, that only material and energy flows are assessed in an LCA, thus ignoring some crucial elements such as supply security and technology reliability and flexibility.

The Methodology

Life-cycle analysis involves the following methodological steps:

- Definition of the product cycle's geographical, temporal, and technical boundaries;
- Identification of the environmental emissions and their resulting physical impacts on receptor areas; and
- Quantifying these physical impacts in terms of monetary values.

These steps describe a 'bottom up', as distinct from a 'top down', methodology for life cycle analysis. Top-down studies use highly aggregated data to estimate the environmental costs of pollution. They are typically undertaken at the national or regional level using estimates of total quantities of emissions and estimates of resulting total damage. The proportion of such damage attributable to certain activities (e.g. the transport sector) is then determined, and a resulting monetary cost derived. The exercise is generic in character, and does not take into account impacts that are site specific. However, its data requirements are relatively minor compared with the 'bottom up' approach. The latter involves analysis of the impact of emissions from a single source along an impact pathway. Thus all technology data are project specific. When this is combined with emission dispersion models, receptor point data, and dose-response functions, monetised values of the impacts of specific environmental externalities can be derived. Data requirements are relatively large compared with the 'top down' methodology, and therefore omissions may be significant.

Traditionally, LCA has omitted the third of the above steps and the final analysis has therefore been expressed in terms of just the biophysical impacts that can be quantified. The extension to include costing of these impacts is generally known as the 'impact pathway' methodology. Essentially, however, it can be considered as a specific application of LCA. This methodology formed the theoretical basis for the European Commission's ExternE study, which was the first comprehensive attempt to use a consistent 'bottom-up' methodology to evaluate the environmental damages associated with a range of different fuel cycles. The European Commission (EC) launched the project in collaboration with the US Department of Energy in 1991. The EC and US teams jointly developed the conceptual approach and the methodology and shared scientific information for its application to a range of fuel cycles. The main objectives were to apply the methodology to a wide range of different fossil, nuclear and renewable fuel cycles for power generation and energy conservation options. Although the US withdrew from the project, a series of National Implementation Programmes to realise the methodology for reference sites throughout Europe was completed. The methodology was subsequently extended to address the evaluation of externalities associated with the use of energy in the transport and domestic sectors.

Table 1: Environmental Damage Costs from Electricity Production in the European Union:

(range: €¢/kWh)

Country	Coal & Lignite	Peat	Oil	Gas	Nuclear	Biomass	Hydro	Photo-voltaics	Wind
Austria				1-3		2-3	0.1		
Belgium	4-15			1-2	0.5				
Germany	3-6		5-8	1-2	0.2	3		0.6	0.05
Denmark	4-7			2-3		1			0.1
Spain	5-8			1-2		3-5			0.2
Finland	2-4	2-5				1			
France	7-10		8-11	2-4	0.3	1	1		
Greece	5-8		3-5	1		0-0.8	1		0.25
Ireland	6-8	3-4							
Italy			3-6	2-3			0.3		
Netherlands	3-4			1-2	0.7	0.5			
Norway				1-2		0.2	0.2		0-0.25
Portugal	4-7			1-2		1-2	0.03		
Sweden	2-4					0.3	0-0.7		
United Kingdom	4-7		3-5	1-2	0.25	1			0.15

Source: European Commission (2003)

Table 1 summarises the results of the EC study for electricity production. The data are based upon specific plants in the countries concerned and combine damages from both local and global pollutants. In the case of the former, therefore, damages are highly dependent upon the population density of the receptor area, and do not reflect industry-wide costs Nevertheless they give an indicative range for each technology when taken over all countries. From this table, nuclear power's appeal as a low-pollution electricity generation option is very evident.

Conversely, environmental damage arising from the combustion of coal in power plants clearly gives cause for concern and consequently the move to gas as an alternative, if more expensive, fuel would be easy to justify for a utility.

The Economics of Environmental Externalities

Externalities are defined as benefits or costs generated as an unintended by-product of an economic activity that do not accrue to the parties involved in the activity and where no compensation takes place. Environmental externalities are benefits or costs that manifest themselves through changes in the physical-biological environment.

Pollution emitted by road vehicles and by fossil fuel fired power plants during power generation is known to result in harm to both people and the environment. In addition upstream and downstream externalities, associated with securing fuel and waste disposal respectively, are generally not included in power or fuel costs. To the extent that the ultimate consumers of these products do not pay these environmental costs, nor compensate others for harm done, they do not face the full cost of the services they purchase (that is, implicitly their energy use is being subsidised) and thus energy resources will not be allocated efficiently.

It's almost a century since Arthur Pigou published his *Wealth and Welfare* (1912), which brought social welfare into the scope of economic analysis. In particular, Pigou is responsible for the distinction between private and social marginal products and costs and the idea that governments can, via a mixture of taxes and subsidies, correct such market failures - or 'internalize the externalities'. At the time these ideas were regarded as an academic curiosity, but a couple of generations later were reincarnated as the Polluter-Pays-Principle (PPP).

Historically, in Australia in common with all OECD countries, the external (largely environmental) damage resulting from the combustion of fossil fuels by power plants have not been 'internalised' in the price of electricity to the ultimate consumer. Thus, effectively, electricity consumption has been subsidised and as a consequence demand (and hence environmental degradation) has been higher than it would have been if pollution control costs had been imposed on the consumer. Recently, in response to their obligations under the Kyoto Protocol, European Union nations have introduced a carbon dioxide (CO_2) emissions trading scheme that is designed to internalise the cost of controlling CO_2 emissions, but it is suffering from a number of practical problems which make the alternative, the politically impossible 'carbon tax', a more appealing option from a practical standpoint. Although these two instruments are equivalent in theory, in practice they can differ significantly if, as would seem likely, the marginal abatement costs of the polluting entities are not known precisely (this divergence is illustrated in *Perman et al*, 2003:254-256)

The Cost of Nuclear Power

Nuclear power plants have a 'front-loaded' cost structure; that is, they are relatively expensive to build but relatively inexpensive to operate. Although costs vary both between and within countries, about two-thirds of the costs of generating electricity from a nuclear power plant are accounted for by fixed costs, with the remainder being operating costs, could be taken as indicative figures. The main fixed costs are capital repayments and interest on loans, but the decommissioning cost is also included in this item. Fuel is a relatively minor component of operating costs, because uranium is in relatively abundant supply in terms of current requirements. Investment cost per kWe at the design stage for nuclear plant is about two and a half times that for coal and three times that for combined cycle gas turbine plants. However, the costs of large scale engineering projects are notoriously difficult to project, being very site specific, and construction cost blow outs are very common in practice. This problem would have a far greater cost impact on nuclear, given that much of the investment for the other two technologies is fabricated in factories and sold under turnkey arrangements.

Once a nuclear power plant has been built, its construction costs have effectively been 'sunk' and the plant's second-hand value is negligible. Thus it makes financial sense to operate the plant continuously based upon the fact that low fuel costs effectively yield a relatively low marginal cost for power production. Thus, currently, nuclear power is the cheapest form of electricity production in most OECD countries with existing plants and utilities are attempting to extend the life of current plants to capitalise on this advantage. However, they appear very reluctant to invest in new nuclear plant without substantial government cost and market guarantees and other subsidies.

For new nuclear power plants, their competitiveness depends on several factors. First, the cost of alternative technologies. Nuclear is likely to be particularly suitable for countries that are not well endowed with coal and/or oil reserves and must therefore import their fossil fuels. Second, it depends on the overall electricity demand in a country and its rate of growth. Third, it depends on the market structure and investment environment. In general, nuclear power's front loaded cost structure is less attractive to a private investor in a liberalised market that values short-term returns than to a government-owned utility that has a longer-term perspective. Private investments in liberalised markets will also depend on the extent to which energy-related environmental externalities (e.g. GHG emissions, emissions of local pollutants, etc.) and the value of energy security have been 'internalised'. In contrast, government investors can incorporate such externalities directly into their decisions, although this implicitly contravenes the PPP. Different countries have different approval processes, regulatory regimes and political systems, all of which impact on risk from an investors viewpoint. Construction delays, for example, can significantly increase interest payments during construction.

Thomas (2006) reports that ‘Forecasts of construction costs have been notoriously inaccurate, frequently being a serious underestimate of actual costs and – counter to experience with most technologies where so-called ‘learning’, scale economies, and technical progress have resulted in reductions in the real cost of successive generations of technology – real construction costs have not fallen and have tended to increase through time.’ This lack of scale economies is not surprising given the lack of orders for new generation (often called ‘Advanced’) reactors. The so-called Generation III and Generation III+ designs are likely to be the preferred technology choice for OECD countries. They differ from previous designs in that they incorporate a greater level of passive, as opposed to engineered, safety. They also benefit from standardisation and simplification of design, factors that should offer economies of scale in production, licensing, and operation.

Joskow (2006) has compared the pre-construction overnight cost (that is, the amount that would be paid out, net of interest charges, if all capital expenses occurred simultaneously) estimates for 75 nuclear power plants built in the US with their actual cost, adjusted to remove the impacts of inflation (Table 2). He notes that nobody has ever underestimated the construction cost of a nuclear power plant at the pre-construction stage!

Table 2: Historical US Construction Cost Experience 75 pre-Three Mile Island plants operating in 1986: $2002/kWe

Construction started	Estimated overnight Cost	Actual overnight cost	Actual/Estimated
1966-67	$560/kWe	$1170/kWe	209%
1968-69	$679/kWe	$2000/kWe	294%
1970-71	$760/kWe	$2650/kWe	348%
1972-73	$1117/kWe	$3555/kWe	318%
1974-75	$1156/kWe	$4410/kWe	381%
1976-77	$1493/kWe	$4008/kWe	269%

Based upon this experience, it is not surprising that Thomas Capps, at the time CEO of Dominion Resources Inc. that currently operates four nuclear plants, in response to new US government incentives[1] (that is, subsidies) to promote a new generation of nuclear power plants, stated:

> President Bush may be cheerleading for nuclear power, but the electric industry is not ready to order new reactors. We aren't going to build a nuclear plant anytime soon. Standard & Poor's and Moody's would have

[1] The Nuclear Power 2010 program, launched in 2002, is a concerted effort by the Bush Administration to encourage a revival of ordering of nuclear plant based upon the next generation (known as Generation III+) of plant designs. Essentially it supports cooperative projects between the US Department of Energy and the power industry.

> a heart attack. And my chief financial officer would, too. (*New York Times*, May 2, 2005)

> Capps argued that the proposed incentives did not go far enough.

> A new 1400-megawatt nuclear power plant is going to cost about $2.6 billion … . It is going to take $6^1/_2$ years to build. While you are building, you have to issue equity. You have to issue bonds; you have to service the bonds with interest. You don't have any money coming in. You have an average of $1.3 billion out for $6^1/_2$ years that is not earning anything. … We are not going to build one under those financial conditions. (*Washington Post*, July 24, 2005)

Capps' main concern was that anti-nuclear protestors would obstruct the operating approval process of new plants through court challenges and that such delays would cause unacceptable financial risks.

The cost of capital (that is, the interest rate) is, together with construction costs, a major determinant of the cost of power from a nuclear plant. Most nuclear plants currently operating in OECD countries were built in an era when the power generation sector was a regulated monopoly. Thus the cost of capital was low, as it was backed by government guarantee. In addition, any increase could be clawed back from consumers in the form of higher prices arising from the full cost recovery nature of the sector pricing regime. Thus investment risk, which effectively was vested in the consumer/tax payer, was minimal and hence the cost of capital reflected this.

However, OECD electricity markets (including that of Australia) have undergone reconstruction, to various degrees, to a model that is driven by competitive forces, and thus the investment risk now falls on the generator rather than consumer. In such circumstances the real cost of capital could be expected to be considerably higher than under the former regime. Of course, this risk could be reduced by government guarantees but this amounts to a subsidy and is therefore in conflict with the competitive market model.

Financial estimates of the cost of electricity generation from new nuclear power plants are subject to large variations, both between and within countries (as can be seen by the construction cost data given in Table 3). Thomas lists a number of reasons for the divergence:

- It is always assumed that new plants would be much cheaper and more reliable than existing plants.
- Those with a vested interest in nuclear power would tend to produce the more optimistic costs and performance forecasts.
- Few orders have been placed in the past two decades on which to base forecasts.
- Very little real data on construction and operating costs are made public.
- All designs currently being considered in the USA and the EU are unproven.

- Different assumptions regarding the cost of capital (which are very evident from Table 3). Real rates of 10 percent, or above, severely compromise the viability of nuclear power yet rates lower than this are difficult to justify for private investors.

Table 3: Forecasts of Generating Costs for New Nuclear Plant

Forecast	Construction Cost (€/kW)	Cost of capital (% real)	Load Factor (%)	Operating Life (years)	Generating Cost (€¢/kWh)	Generating Cost (A¢/kWh)
Canadian Nuclear Ass	1557	10	90	30	4.82	8.03
Chicago University	810 1216 1460	12.5	85	40	4.23 4.96 5.69	7.05 8.27 9.48
IEA/NEA	1606-3650	5 10	85	40	1.75-3.94 2.6-5.5	2.92-6.57 4.33-9.17
Lappeenranta University	1748	5	91	40	2.23	3.72
OXERA	2372 (first unit) 1679 (later unit)		95	40		
MIT	1622	11.5	85 75	40 25	5.4 6.4	9.00 10.67
Performance & Innovation Unit	<1226	8 8 15	>80	30 15 15	3.37 4.13 5.53	5.62 6.88 9.22
RAE	1679	7.5	90	40	3.36	5.60
UBS	2044	-	91	45	3.06	5.10
EPR	2031	8	90.3	60	3.00	5.00
Sizewell B	5110	-	84	40	-	
Gittus	1708	5	90	40	2.18	3.63

Source: Adapted from Thomas (2005)

Energy Subsidies

Support that lowers the cost of power generation can take many forms, including support to the use of inputs (e.g. water, fuels, etc.), public financing at interest rates below the market value, tax relief on corporate income, lump sum support to fixed capital investment in research and development, etc. Examples include the exemption of government-owned electricity generators from corporate income tax payments (increasing the relative after tax rate of return compared with electricity generation by private enterprises) or the provision of loans at interest rates below market rates, or over repayment periods in excess of market terms (which favour capital intensive energy forms).

Energy subsidies are particularly prevalent in developing countries, where energy prices typically contain a 'social' subsidy to enable the poor to receive basic lighting services. Perhaps the most extreme case of energy subsidies in the developed world involves the nuclear power industry, where various OECD governments subsidise the industry's fuel supply services, waste disposal, fuel processing, and research and development. In addition, they also limit the liability of plants in case of accident, and help them clean up afterwards.

Civil Liability and Insurance

Civil liability for nuclear damage is limited by both national legislation and international conventions. In the case of the latter, a 1997 amendment to the IAEA Vienna Convention limits operator liability to 300 million SDRs (about €360 million). It entered into force in 2003, but with few members. In 2004 contracting parties to the OECD Paris and Brussels Conventions set liability levels at €1500 million, but these have yet to be ratified. Thereafter, there appears to be a tacit acceptance that the relevant state will make funds available to cover any excess.

In the USA the Price-Anderson Act, the world's first comprehensive nuclear liability law, has since 1957 limited the liability of US nuclear electrical generating facilities in the event of an accident. Under the terms of its 20 year renewal in 2005, individual operators are responsible for two layers of insurance cover. Private cover of $300 million per nuclear site from private insurers, combined with a joint fund of $96 million per reactor (adjusted for inflation) paid retrospectively in instalments (if required). The total provision amounts to $10 billion. Above this figure, the US Congress acts as insurer of last resort.

Whether these liability limits constitute a subsidy designed to encourage the installation of nuclear power facilities or simply government responsibility for providing last resort assistance for victims of major disasters, natural or otherwise, is a contentious issue. Without them it is unlikely that the US or EU nuclear power industries could purchase full indemnity in the commercial insurance marketplace.

Internalising Environmental Externalities

Table 1 illustrated the environmental benefits offered by nuclear power, as opposed to its fossil fuel (and particularly coal) counterparts. However, these were damage costs, whereas the appropriate pricing of carbon would be based upon control costs. Damage costs are a measure of society's loss of wellbeing resulting from the damage arising from a specific adverse environmental impact, and are appropriately included in cost-benefit analyses. Control costs are what it costs society to achieve a given standard that restricts the extent of the impact to an acceptable level and this is what is required for meeting Kyoto Protocol-style obligations. Essentially, unit control costs can be calculated simply by dividing the cost of mandated controls by the emissions reduction achieved by the controls. The implicit assumption in control costing is that society controls pollution until the benefit of additional controls would be outweighed by the cost of their imposition.

Where environmental externalities are 'internalised' (even, if only partially) then they can legitimately be included in the financial analysis as they represent a true cost to the investor. The European Emissions Trading Scheme (ETS) was established in 2005 to reduce EU CO_2 emissions in accordance with its obligations under the Kyoto Protocol. In theory, setting a pollution emissions 'cap', allocating permits to pollute to this cap, and facilitating permit trading amongst polluters should ensure a least-cost reduction of total pollutants to (at most) the level of the cap. To the extent that electricity generators using fossil fuel plants and other significant emitters of CO_2 exceed their quota, they will be obliged to purchase permits and pass the cost on to their customers. Thus a 'price' for carbon is established (that is, the environmental externality is, at least partially, internalised) and the cost of electricity from fossil fuel plants would rise correspondingly. At least that's the theory.

In practice, the scheme's first year of operations has been dysfunctional. Lax allocation of allowances by most member states resulted in the distribution of permits to the value of 1829 million tonnes CO_2 in 2005. Actual emissions were only 1785 million tonnes. So, in aggregate, the market was experiencing over-supply of permits and the scheme was simply not reducing emissions of CO_2. In fact, only four of the 25 member states had targets which were lower than their actual emissions! The exceptions at the sector level were power stations which were set, in general, very tight targets. Thus the scheme has really only acted as a tax on power stations with a resulting increase in electricity prices (which could probably have been accomplished far more efficiently with a simple energy tax).

In late August 2006, permits were trading for around €16-17/tonne CO_2 (A\$27-29/tCO_2), equivalent to about 1.5 euro cents/kWh for coal-fired generation, having declined significantly when the market was informed of the over-allocation noted above. At this price level, the disincentive for using coal is very low. But it is an actual cost that must be paid by generators and thus indirectly financially encourages non-fossil sources of electricity supply.

More generally, the cost of controlling global CO_2 emissions to a universally agreed specified level should be the actual control cost imposed on emitters, not that of a highly contrived and limited market such as the EU ETS. It is difficult to give even a ballpark figure as to what this cost could be, since estimates of the marginal cost of GHG emissions damage cover a vast range. Toll (2005) has concluded that, based upon a survey of 103 estimates, 'one can therefore safely say that, for all practical purposes, climate change impacts may be very uncertain but is unlikely that the marginal damage costs of carbon dioxide emissions exceed \$50/tC (or approximately A\$68/tC or A\$18.50/tCO_2) and are likely to be substantially smaller than that'. Since, logically, control costs must be less than damage costs this would represent an upper bound. However, the cost would be far too uncertain to have confidence that a (politically unpopular) carbon tax, imposed universally, would achieve the desired objective of reducing CO_2 emissions from the power sector to an acceptable level.

The Debate in Australia

In Australia, the Australian Nuclear Science and Technology Organisation (ANSTO) fuelled the debate by commissioning a study entitled *Introducing Nuclear Power to Australia: an Economic Comparison* from John Gittus, a UK-based consultant.[2] The report concluded that, with appropriate subsidies, a 'new' generation of nuclear power plants could produce electricity in Australia at a cost that was competitive with coal. Gittus then built in to his analysis the cost of damage arising from emissions of CO_2 and local pollutants from fossil fuel plants, thus giving nuclear power a pronounced 'economic' advantage. Economists would, of course, recognise this transition from a financial analysis to a cost benefit analysis, but would question its partial nature. What Gittus has produced is a 'mongrel' analysis. A correct formulation of an economic analysis would also net out of the calculations all subsidies and taxes, and shadow price other factors of production where appropriate. This would give a very different picture of the true resource use associated with a nuclear plant (i.e. a proper cost benefit analysis). As noted earlier, however, it is the cost of controlling CO_2 emissions that is the relevant add-on environmental cost for power stations operating in the private sector, and at present this cost is negligible in Australia.

Without imposing a cost on carbon, the Australian government is effectively subsidising domestic carbon emitting industries. To 'correct' this imbalance its answer appears to be the provision of subsidies for 'negligible' carbon emitting technologies (such as nuclear and renewables). However, as has already been noted, subsidies not only result in higher demand and consequently greater pollution than in a non-subsidised regime, they also result in a net loss of welfare to society.

There is currently a proposal before the state governments to introduce a cap-and-trade carbon permit trading mechanism for power utilities in Australia, under the auspices of the National Emissions Trading Taskforce. If properly designed and with an effective 'cap', this should impose control costs on power stations that will ultimately be passed on to the consumer of electricity in the form of higher prices. Incentives to modify carbon emitting activities then arise for both producers and consumers of electricity. Since the permits will have value, producers will have an incentive to adopt low carbon energy technologies (such as nuclear or renewables), carbon sequestration, or improve the efficiency of their current carbon technologies in order to sell surplus permits, or at least minimise

---

[2] It is not the purpose of this paper to give a critique of the Gittus study, which contains a number of unrealistic assumptions. However, the error noted here is particularly significant in the context of carbon costing.

their permit purchase requirements. Consumers will be forced by higher prices to reduce their energy demand and/or adopt more efficient appliances and energy use practices. It should be remembered, however, that the Commonwealth government is not a party to this initiative, so the integrity of the scheme may be compromised by its inability to operate outside of conforming (currently Labor-controlled) states.

Thus, ironically, the very mechanism that has encouraged excessive environmental damage in much of the world, and hence contributed significantly to its accompanying high social costs — *the market place* — can be an important avenue by which environmental objectives and targets could be met. However, to do so effectively, both the implicit and explicit subsidies that have contributed to so much of the problem in the first place need to be removed.

Conclusion

Despite a recent revival of interest in nuclear power, the prospects for private investment in nuclear plant in a liberalised electricity market is unlikely without significant government support. High capital cost, uncertain construction costs, potential delays in construction and licensing, the absence of policies to place a price on CO_2 emissions from fossil fuel power plants, and lack of experience and economies of scale in nuclear plant operations are features that would make nuclear power technology particularly unattractive to private investors in Australia. Added to these are public concerns over nuclear safety which could make site selection particularly difficult and expensive if public opposition involves significant delays in the construction and licensing of nuclear power stations.

The over-riding issue, however, is the inability of governments to adopt the PPP in the context of power generation. The advocates of nuclear power have a justifiable argument that its low level of GHG emissions should be attributed a value when considering technologies for new electricity generating capacity, if the costs of meeting CO_2 reduction targets are not imposed on the polluters. But politically it appears less problematic to subsidise the non-polluter than tax the polluter.

References

European Commission (2003), 'External Costs: Research Results on Socio-Environmental Damages Due to Electricity and Transport', EUR 20198, Office for Official Publications of the European Communities, Luxembourg.

Joskow, P. (2006), 'Prospects for Nuclear Power: A US Perspective', Presentation to the University of Paris (Dauphine), 19May, Available at: http://www.dauphine.fr/cgemp/Manifestations/joskow%20conference/geopolitics%20joskow%2024%20mars.pdf#search=%22joskow%20nuclear%20dauphine%22

Perman, R., Y. Ma, J. McGilvray and M. Common (2003), *Natural Resource and Environmental Economics*, 3rd edition, Pearson Education, London.

Thomas, S. (2005), 'Nuclear Power — Myth and Reality: The Economics of Nuclear Power', Nuclear Issues Paper No. 5, Heinrich Böll Foundation, available at: http://www.boell.de/downloads/oeko/NIP5ThomasEndf.pdf.

Toll, R. (2005), 'The Marginal Costs of Carbon Dioxide Emissions: An Assessment of the Uncertainties', *Energy Policy* 33:2064-2074.

The author acknowledges helpful comments provided by two anonymous referees in the preparation of this paper.