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The Economics of Nuclear Power: An Update

By Steve Thomas

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Edited by the Heinrich Böll Foundation

Heinrich-Böll-Stiftung
Die grüne politische Stiftung

Schumannstraße 8 10117 Berlin
Telefon 030.285 34-0 Fax 030.285 34-109 **www.boell.de**

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1. Introduction

The severe challenge posed by the need to reduce emissions of greenhouse gases, especially in the electricity generation sector, has led to renewed interest in the construction of nuclear power plants. These would initially replace the aging stock of existing reactors, then meet electricity demand growth, and eventually replace some of the fossil-fired electricity-generating plants. They would also be built in new markets that up to now have not used nuclear power. In the longer term, the promise is that nuclear power could take over some of the energy needs currently being met by direct use of fossil fuels. For example, nuclear power plants could be used to manufacture hydrogen, which would replace use of hydrocarbons in road vehicles.

The public is understandably confused about whether nuclear power really is a cheap source of electricity. Cost estimates for new nuclear plants have been escalating at an alarming rate, and in the past decade, construction cost-estimates have increased five-fold, with every expectation that costs will increase further as the designs are firmed up. Yet, in recent years, governments such as those of the United States, the United Kingdom, Germany, and Italy have become increasingly determined in their attempts to maintain existing nuclear plants in service and revive nuclear ordering, on the grounds that nuclear power is the most cost-effective way to combat climate change. Utilities are determined to operate their existing plants for as long as possible and have given verbal support to the need for new nuclear power plants, but they are reluctant to build new nuclear power plants without cost- and market guarantees and subsidies. Some of this apparent paradox is relatively easily explained by the difference between the running of costs only of nuclear power, which are usually relatively low, and the overall cost of nuclear power – including repayment of the construction cost – which is substantially higher. Thus, once a nuclear power plant has been built, it may make economic sense to keep the plant in service even if the overall cost of generation, including the construction cost, is higher than the alternatives. The cost of building the plant is a "sunk" cost that cannot be recovered, and the marginal cost of generating an additional kWh could be small.

The objective of this report is to identify the key economic parameters that determine the cost of nuclear electricity, commenting on their determining factors. It shows that without subsidies and guarantees from electricity consumers and taxpayers, new nuclear power plants will not be built.

2. The world market for nuclear plants: existing orders and prospects

Over the past decade, there has been increasing talk about a "Nuclear Renaissance" based on two factors. A new generation of nuclear power plants, so-called Generation III+, would be cheaper and easier to build, safer, and produce less waste (see Appendix 1 for a description of the Generation III+ designs). Ordering would be not only in countries where nuclear ordering had not been problematic, such as France, India, and Korea, but also in countries such as the United States, the United Kingdom, Italy, as well as Germany, which seem to have turned away from nuclear power. The United States and the United Kingdom are particular targets for the nuclear industry for a number of reasons:

- The UK and US programs are closer to placing orders for Generation III+ designs than elsewhere in Europe and North America, apart from Finland and France;
- The United Kingdom and United States are seen as pioneers of nuclear power and, therefore, new orders for nuclear plants in these countries carry additional prestige; and
- Economic experiences with nuclear power in the United Kingdom and the United States were so bad that, a decade ago, it seemed unlikely that orders would be possible, so reviving these markets would be a particular coup.

The list of plants currently on order (Tables 2, 3, and 4) suggests that the Renaissance is largely talk and is geographically limited. In January 2010, there were 55 plants under construction worldwide, with a capacity of 51 GW compared to 443 plants already in service with a capacity of 375 GW (Table 1). Of the 30 units on which construction had started after 2005, all except one (in France) were in China (20), South Korea (5), or Russia (4) (Table 3). All except six of these units were supplied by indigenous suppliers. The Western vendors active in Europe – Westinghouse and Areva NP – have won just two orders outside China: Areva NP's Olkiluoto order for Finland and its Flamanville order for France. These eight orders and the four units ordered from South Korea by the UAE in December 2009 are the only ones for Generation III+ designs.

So without China, the order book for new nuclear power stations would look much weaker. Most of its orders are being supplied by Chinese companies and are based on the French design it ordered in 1980 for its Daya Bay site. It remains to be seen whether China has the human and financial resources to continue to finance orders at the rate it had in 2008 and 2009, when work on 15 new units was started. The most likely outcome for China, given the need for China to use its limited capital resources carefully, is that it will continue to place a small number of nuclear orders on the international market – much fewer than forecast by the Chinese government or by the nuclear industry – while trying to build up its capability through its own nuclear power plant supply industry. The designs it is supplying now are too old to be relevant to the West.

Russia, like China, has had very ambitious plans to expand nuclear power. In 2008, it had plans to commission 26 new nuclear units (about 30 GW) by 2025, but by 2009, this target had already slipped to 2030.[1] Four units dating back to the 1980s are listed as still being under construction and nearly complete, but this has been the situation for a decade or more (see Table 3). If the need for new nuclear capacity was urgent and the financial resources were available, these units would surely have been completed by now. Reliable information from Russia on the status of construction at nuclear plants is difficult to get and these plants may not currently be under construction. A particular doubt is the Kursk 5 plant, which uses the same technology as the Chernobyl plant and which would be very controversial if brought on-line.

Table 1. Nuclear capacity in operation and under construction: January 2010

	Operating: Cap MW (no. units)	**Construction: Cap MW (no. units)**	**% elec nuclear (2008)**	**Technologies[2]**	**Suppliers**
Argentina	935 (2)	692 (1)	6	HWR	Siemens AECL
Armenia	376 (1)	-	39	WWER	Russia
Belgium	5863 (7)	-	54	PWR	Framatome
Brazil	1766 (2)	-	3	PWR	Westinghouse Siemens
Bulgaria	1966 (2)	1906 (2)	33	WWER	Russia
Canada	12577 (18)	-	15	HWR	AECL
China	8438 (11)	19920 (20)	2	PWR, HWR, WWER	Framatome, AECL, China, Russia
Taiwan	4949 (6)	2600 (2)	20	PWR, BWR	GE, Framatome
Czech Rep	3678 (6)	-	32	WWER	Russia
Finland	2696 (4)	1600 (1)	30	WWER, BWR, PWR	Russia, Asea, Westinghouse
France	63260 (59)	1700 (1)	76	PWR	Framatome
Germany	20470 (17)	-	28	PWR, BWR	Siemens
Hungary	1755 (4)	-	37	WWER	Russia
India	3984 (18)	2708 (5)	2	HWR, FBR, WWER	AECL, India, Russia

1 *Nucleonics Week*, "Russia Stretches Out Schedule for New Reactor Construction," March 26, 2009.
2 See glossary and Appendix 1 for an overview of the technologies.

Iran	-	915 (1)		WWER	Russia
Japan	46823 (53)	1325 (1)	25	BWR, PWR	Hitachi, Toshiba, Mitsubishi
S Korea	17647 (20)	6520 (6)	36	PWR, HWR	Westinghouse, AECL, Korea,
Mexico	1300 (2)	-	4	BWR	GE
Netherlands	482 (1)	-	4	PWR	Siemens
Pakistan	425 (2)	300 (1)	2	HWR, PWR	Canada, China
Romania	1300 (2)		18	HWR	AECL
Russia	21743 (31)	6894 (9)	17	WWER, RBMK	Russia
Slovak Rep	1711 (4)	810 (2)	56	WWER	Russia
Slovenia	666 (1)	-	42	PWR	Westinghouse
S Africa	1800 (2)	-	5	PWR	Framatome
Spain	7450 (8)	-	18	PWR, BWR	Westinghouse, GE Siemens
Sweden	8958 (10)	-	42	PWR, BWR	Westinghouse, Asea
Switzerland	3238 (5)	-	39	PWR, BWR	Westinghouse, GE Siemens
Ukraine	13107 (15)	1900 (2)	47	WWER	Russia
UK	10097 (19)	-	13	GCR, PWR	UK, Westinghouse
USA	100683 (104)	1165 (1)	20	PWR, BWR	Westinghouse, B&W, CE, GE
WORLD	**375136 (443)**	**50955 (55)**			

Source: IAEA, http://www.iaea.or.at/programmes/a2/

India ordered a small number of plants from Western suppliers in the 1960s and 1970s, but a nuclear weapons test in 1975 using material produced in a Canadian research reactor led to the cutting of all contact with Western suppliers. India has continued to build plants using the 1960s Canadian design it had ordered. These have a poor record of reliability and frequently take much longer to build than forecast, so the completion dates in Table 2 should be treated with skepticism. The United States also broke off cooperation in 1998 after further weapons tests but in 2005, India and the United States negotiated a deal over technological cooperation in civil nuclear power. Canada also resumed sales of nuclear material in 2005. Since then Rosatom of Russia (up to 4 WWER-1200 units), Westinghouse (up to 8 AP1000s), Areva (up to 6 EPRs) and GE-Hitachi (up to 8 ABWRs) have all claimed they have agreements to supply nuclear plants there, but none of these have been turned into firm orders. India's own nuclear industry expects to build a large number of new plants using a variety of technologies, including fast reactors, heavy-water reactors, and thorium-fueled plants. The Indian government has set a target of 63,000 MW of new nuclear capacity to be in service by 2032. It would be astonishing, considering its past record, if India even got close to meeting this target.

Table 2. Nuclear power plants under construction worldwide ordered from 1999 onwards

Country	Site	Reactor type	Vendor	Size MW	Construction start	Construction stage (%)	Expected operation
China	Fangjiashan 1	PWR	China	1000	2008	0	-
China	Fangjiashan 2	PWR	China	1000	2009	0	-
China	Fuqing 1	PWR	China	1000	2008	0	-
China	Fuqing 2	PWR	China	1000	2009	0	-
China	Haiyang 1	PWR	China	1000	2009	0	-
China	Hongyanhe 1	PWR	China	1000	2007	20	-
China	Hongyanhe 2	PWR	China	1000	2008	0	-
China	Hongyanhe 3	PWR	China	1000	2009	0	-
China	Hongyanhe 4	PWR	China	1000	2009	0	-
China	Lingao 3	PWR	China	1000	2005	60	2010
China	Lingao 4	PWR	China	1000	2006	50	2010
China	Ningde 1	PWR	China	1000	2008	10	-
China	Ningde 2	PWR	China	1000	2008	5	-
China	Ningde 3	PWR	China	1000	2010	5	-
China	Qinshan 2-3	PWR	China	610	2006	50	2010
China	Qinshan 2-4	PWR	China	610	2007	50	2011
China	Sanmen 1	PWR	W'house	1000	2009	10	-
China	Sanmen 2	PWR	W'house	1000	2009	10	-
China	Taishan 1	PWR	Areva	1700	2009	0	-
China	Yangjiang 1	PWR	W'house	1000	2009	10	-
China	Yangjiang 2	PWR	W'house	1000	2009	0	-
Taiwan	Lungmen 1	ABWR	GE	1300	1999	57	2011
Taiwan	Lungmen 2	ABWR	GE	1300	1999	57	2012
Finland	Olkiluoto 3	EPR	Areva	1600	2005	40	2012
France	Flamanville 3	EPR	Areva	1700	2007	25	2012

India	Kaiga 4	Candu	India	202	2002	97	2010
India	Kudankulam 1	WWER	Russia	917	2002	90	2011
India	Kudankulam 2	WWER	Russia	917	2002	79	2011
India	PFBR	FBR	India	470	2005	37	-
India	Rajasthan 6	Candu	India	202	2003	92	2010
Japan	Shimane 3	BWR	Toshiba	1325	2007	57	2011
Korea	Shin Kori 1	PWR	Korea	960	2006	77	2010
Korea	Shin Kori 2	PWR	Korea	960	2007	77	2011
Korea	Shin Kori 3	PWR	Korea	1340	2008	29	2013
Korea	Shin Kori 4	PWR	Korea	1340	2009	29	2014
Korea	Shin Wolsong 1	PWR	Korea	960	2007	49	2011
Korea	Shin Wolsong 2	PWR	Korea	960	2008	49	2012
Pakistan	Chasnupp 2	PWR	China	300	2005	25	2011
Russia	Beloyarsky 4	FBR	Russia	750	2006	12	-
Russia	Leningrad 2-1	WWER	Russia	1085	2008	0	-
Russia	Novovoronezh 2-1	WWER	Russia	1085	2008	5	-
Russia	Novovoronezh 2-2	WWER	Russia	1085	2009	0	-
TOTAL				40778			

Sources: PRIS Data Base, http://www.iaea.org/programmes/a2/index.html; *Nuclear News*, world list of nuclear plants

Note: Includes only units larger than 100 MW. Construction stage is as reported by Nuclear News in March 2009

South Korea has continued to order nuclear plants throughout the past two decades – five in the past four years – and it already gets 36 percent of its electricity from nuclear plants (see Table 3). The six units under construction may increase this to 50 percent, leaving little scope for many more orders for the home market. This may account for the decision to move into export markets and winning four orders from UAE at a low reported price.

Japan is another country that has consistently forecast large increases in nuclear capacity not matched by actual orders. Japanese companies supply these plants using technology licensed from Westinghouse and GE. It may take up to 20 years to get approval to build at sites in Japan, although once construction starts, completion is usually quick (four years typically) and does not usually go beyond schedule. A series of accidents at plants in Japan, often badly mishandled, have led to an increase in public concern about nuclear power, and finding sites for further plants is likely to be difficult. Only one plant was under construction at the start of 2010 (see Table 2) and it seems likely that no more than a trickle of orders will be placed for Japan.

Table 3 shows that there are 17 uncompleted units on which construction started before 1990 that might still be brought on-line, but on which work is not necessarily being actively done. For these, the quoted degree of completion may be misleading. Plants reported to be less than 33 percent complete are likely to have seen only site preparation with no actual reactor construction. In addition, the completion times for units under construction in Taiwan – ordered in 1996 when completion was expected in 2004 – have slipped by eight years. The Watts Bar reactor in Tennessee (USA) is a particularly interesting example. Construction of it and its twin were started in 1973 but work was continually delayed. Unit 1 was finally completed in 1996 at a cost of more than $6 billion,[3] but work on unit 2 was effectively halted in 1985 when construction was reported to be 90 percent complete.[4] Work restarted on the plant in 2007, when it was expected the plant would be complete by 2013 for $2.5 billion.

Table 3. Nuclear power plants on which construction started before 1990

Country	Site	Tech	Vendor	Size MW net	Construction start	Construction %	Expected operation
Argentina	Atucha 2	HWR	Siemens	692	1981	87	2010
Brazil	Angra 3*	PWR	Siemens	1275	1976	10	
Bulgaria	Belene 1*	WWER	Russia	953	1987	0	
Bulgaria	Belene 2*	WWER	Russia	953	1987	0	
Iran	Bushehr	WWER	Russia	915	1975	99	2010
Romania	Cernavoda 3*	Candu	AECL	655	1983	23	
Romania	Cernavoda 4*	Candu	AECL	655	1983	12	
Romania	Cernavoda 5*	Candu	AECL	655	1983	8	
Russia	Balakovo 5*	WWER	Russia	950	1986	High	
Russia	Kalinin 4	WWER	Russia	950	1986	High	
Russia	Kursk 5*	RBMK	Russia	925	1985	High	
Russia	Volgodonsk 2	WWER	Russia	950	1983	High	2010
Slovakia	Mochovce 3	WWER	Russia	405	1983	40	
Slovakia	Mochovce 4	WWER	Russia	405	1983	30	

3 *Chattanooga Times*, “Tennessee: Estimates Rise for Nuclear Plant,” section A1, December 12, 2008.
4 http://www.tva.gov/environment/reports/wattsbar2/seis.pdf.

Ukraine	Khmelnitsky 3	WWER	Russia	950	1986	30	2015
Ukraine	Khmelnitsky 4	WWER	Russia	950	1987	15	2016
USA	Watts Bar 2	PWR	W'house	1165	1972	70	2012
TOTAL				14403			

Sources: PRIS Data Base, http://www.iaea.org/programmes/a2/index.html; *Nuclear News*, world list of nuclear plants

Notes

1. Construction work has stopped on reactors marked *

Table 4. Nuclear power plant orders on which construction had not started by Jan 1 2010

Country	**Site**	**Tech**	**Vendor**	**Size MW net**	**Order date**
China	Taishan 2	EPR	Areva	1700	2008
UAE	Unknown	AP-1400	Korea	4 x 1400	2009

Source: Various press reports

In 2009, the Tennessee Valley Authority, the utility that owns Watts Bar, also began to investigate the possibility of restarting construction of two units at its Bellefonte site in Alabama (USA). Construction on this two-unit site started in 1974, and when work was halted in the mid-1980s,[5] work was estimated to be more than 90 percent complete on unit 1 and about 60 percent complete on unit 2. Completing work on designs such as those at Bellefonte and Watts Bar that are now about 40 years old raises particular issues, given that it is highly unlikely these designs would be licensable if they were submitted to the safety authorities now.

3. Key determinants of nuclear economics

There are several important determinants of the cost of electricity generated by a nuclear power plant (see Table 5). Some of these are intuitively clear while others are less obvious. Areva NP, the French vendor of nuclear power plants, estimates[6] that 70 percent of the cost of a kWh of nuclear electricity is accounted for by the "fixed" costs from the construction process, 20 percent by "fixed" operating costs, and the other 10 percent by "variable" operating costs. The main fixed construction costs are the costs of paying interest on the loans and repaying the capital, but the decommissioning

5 http://web.knoxnews.com/pdf/082708bellefonte-reinstatement.pdf.

6 http://www.areva.com/servlet/BlobProvider?blobcol=urluploadedfile&blobheader=application%252Fpdf&blobkey=id&blobtable=Downloads&blobwhere=1246874807296&filename=Overview_June_2009%252C0.pdf.

cost is also included. The cost per kWh is also determined by the reliability of the plant: The more reliable it is, the more units of output it will produce, over which amount the fixed costs can be spread. The main running costs are the costs of operation, maintenance, and repair rather than fuel.

Table 5. Nuclear economics – cost elements (based on Areva NP)

Share	Description
70%	Fixed costs for construction: interest on loans/repaying capital
20%	Fixed operations (cost/kWh): depends on reliability of plant (e.g., load factor)
10%	Variable operations: operation, maintenance, repair, fuel
Not included	Decommissioning, waste disposal and management, risk of meltdown, environmental and human harm

Prior to looking at these costs in detail, it is important to note that there is a significant mismatch between the interests of commercial concerns and society in general. Huge costs that will only be incurred far in the future have little weight in commercial decisions because such costs are "discounted" (see Appendix 3). This means that waste disposal costs and decommissioning costs, which are at present no more than ill-supported guesses, are of little interest to commercial companies. From a moral point of view, the current generation should be extremely wary of leaving such an uncertain, expensive, and potentially dangerous legacy to a future generation to deal with when there are no ways of reliably ensuring that the current generation can bequeath the funds to deal with them, much less bear the physical risk. Similarly, the accident risk also plays no part in decision-making because the companies are absolved of this risk by international treaties that shift the risk to taxpayers.

3.1. Construction cost and time

Construction cost is the most widely debated parameter, although other parameters, such as the cost of capital and the reliability of the plant, are of comparable importance to the overall cost of each kWh of electricity. To allow costs to be compared, utilities generally quote the "overnight" cost, which, as well as the cost of the plant, includes the cost of the first charge of fuel but not the interest incurred on borrowings during the construction of the plant, usually known as interest during construction (IDC). To allow comparisons between reactors with different output capacities, costs are often quoted as a cost per installed kW. Thus, a nuclear power plant costing $2,400 million with an output rating of 1200 MW would have a cost of $2,000/kW. There are a number of factors that explain why there is such controversy about forecasts of construction cost.

3.1.1. Unreliability of data

Many of the quoted construction cost forecasts should be treated with skepticism. The most reliable indicator of future costs has generally been past costs.[7] 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. However, US utilities were required to publish reliable accounts of the construction costs of their nuclear plants for the economic regulator (who only allowed cost recovery from consumers for properly audited costs) and past US costs are reliable. The cost of the Sizewell B (UK) plant is also reasonably well-documented because aside from the company building, it had few other activities in which the construction cost could be "disguised."

The next best option are the prices quoted in calls for tenders. While the actual cost of a nuclear plant is generally higher (often significantly) than the contract price, the vendor should at least have to fully price the order. If the order is a genuine "turnkey" order – that is, a fixed price order in which the customer pays only the contract price no matter what the actual costs are – the vendor has a particular incentive to make the bid price as accurate as possible.

Turnkey terms are only possible where the vendor is confident that they can control all aspects of the total construction cost. The current generation of gas-fired power plants, combined cycle gas turbine (CCGT) plants, are often sold under turnkey terms because they are largely built in factories controlled by the vendor and require relatively little on-site work. In the mid-1960s, the four major US nuclear vendors sold a total of 12 plants under turnkey terms, but lost massive amounts of money because of their inability to control costs. Since then, it is unlikely that any vendor has risked offering a complete plant on turnkey terms. Note that individual items of equipment may be purchased on turnkey terms, but any price for a nuclear plant quoted as being on turnkey terms should be regarded with considerable skepticism. The Olkiluoto order is usually described as "turnkey," with Areva being responsible for management of the construction. However, as is described in Section 9, Areva was in dispute with the customer, Teollisuuden Voima Oyj (TVO), over the terms of the contract and specifically which party pays for cost-overruns. Note, some vendors use the term "turnkey" rather loosely and they sometimes mean no more than that the contract covers the whole plant.

Indicative prices quoted by vendors must however be treated with skepticism. GE-Hitachi, has acknowledged that vendors have not been careful enough in giving indicative prices and the overoptimistic prices quoted have become counterproductive. The GE-Hitachi (GEH) president and

7 Estimates of future costs have almost invariably been overoptimistic, based on faulty expectations about learning, scale, and innovation effects that have not been reflected in costs.

CEO, Jack Fuller, said: “When reactor construction projects cost much more than projected, that undermines the public’s confidence in the industry.”[8]

Prices quoted by those with a vested interest in the technology but no influence over prices – including industry bodies such as the World Nuclear Association and equivalent national bodies – clearly must be viewed with skepticism. Prices quoted by international agencies, such as the Nuclear Energy Agency, also must be treated with care, particularly when they are based on indicative rather than real costs. Generally, these costs are provided by national governments, which may have their own reasons to show nuclear power in a good light, and which generally do not base their figures on actual experience.

Forecasts of construction costs have been notoriously inaccurate, frequently being a serious underestimation 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. There is also some inevitable variability from country to country as a result of local labor costs and the cost of raw materials such as steel and concrete.

3.1.2. Difficulties of forecasting

There are a number of factors that make forecasting construction costs difficult. First, all nuclear power plants currently on offer require a large amount of on-site engineering, the cost of which might account for about 60 percent of the total construction cost, with the major equipment items – such as the turbine generators, the steam generators, and the reactor vessel – accounting for a relatively small proportion of total cost.[9] Large projects involving significant amounts of on-site engineering are notoriously difficult to manage and to control costs on. For example, in the United Kingdom, the costs of the Channel Tunnel and the Thames Barrier were well above forecast costs. Some Generation IV designs are expected to be largely factory-built and costs are expected to be much easier to control in a factory.

Second, there are also site-specific factors that might make a significant difference to costs, for example the method of cooling. GEH CEO Fuller said that the problem with such [generic] estimates was that no one made clear “what the number represented […] Did it include fuel? Was the plant on saltwater or freshwater?” Danny Roderick, GEH senior vice president, nuclear plant

8 *Nucleonics Week*, “GEH: Cost Estimates Did Industry a ‘Disservice,’” September 17, 2009.

9 As a result of the difficulty of controlling construction costs, the World Bank does not to lend money for nuclear projects. See *Environmental Assessment Sourcebook: Guidelines for Environmental Assessment of Energy and Industry Projects, Volume III*, World Bank Technical Paper 154 (Washington, DC: World Bank, 1991).

projects, said: "GEH had seen plant costs change by $1 billion depending on whether the plant is cooled by saltwater or freshwater."[10]

Third, costs increase if design changes are necessary, for example if the original detailed design turns out to be poor, or the safety regulator requires changes in the design, or the design was not fully worked out before construction started. In response to these problems, plant constructors now aim to get full regulatory approval before construction starts, as with the proposed US combined Construction and Operation Licenses (COL), and they require designs to be as fully worked out as reasonably possible before construction starts. In practice, vendors often claim their designs are complete, as was the case with the Olkiluoto plant under construction in Finland (see Section 9). But even after four years of construction, in 2009, it had become clear the design was still far from complete. The risks posed by design changes cannot be entirely removed, especially with new designs whereby unanticipated problems might be introduced by the construction process or whereby the regulator cannot agree with design details as they are filled in. For example, at the Olkiluoto plant by 2009, the regulator expressed serious concerns about the adequacy of the proposed control and instrumentation systems. Without major changes, the regulator was not willing to license the plant (see Section 9)

Experiences within operating reactors might also lead to the need for changes in the design after construction has started. For example, a major nuclear accident would necessarily lead to a review of all plants under construction (as well as all operating plants) and important lessons could not be ignored simply because licensing approval of the existing design had already been given.

3.1.3. Learning, scale economies, and technical progress

The expectation for most technologies is that successive generations of design will be cheaper and better than their predecessors because of factors such as learning, economies of scale, and technical change. How far nuclear technology has improved through time is a moot point, but costs have clearly not fallen. The reasons behind this are complex and not well understood, but factors that are often quoted are increased regulatory requirements (note, the standards have not increased, but the measures found to be necessary to meet these standards have) and unwise cost-cutting measures with first-generation reactors.

The paucity of orders for current generations of reactors, especially those with properly documented costs, makes it difficult to know whether costs have stabilized yet, let alone begun to fall. However, "learning" – in other words, improvements in performance through repetition – and scale economies are two-way processes. In the 1970s, the major reactor vendors were receiving up to 10 orders per

10 *Nucleonics Week*, "GEH: Cost Estimates."

year. This allowed them to set up efficient production lines to manufacture the key components and allowed them to build up skilled teams of designers and engineers. How much these economies of number produced reduced costs is difficult to estimate. A Nuclear Energy Agency report from 2000 suggests that the intuitive expectation that economies of number would be large may not be accurate. It stated:[11]

> The ordering of two units at the same time and with a construction interval of at least 12 months will result in a benefit of approximately 15 percent for the second unit. If the second unit is part of a twin unit the benefit for the second unit is approximately 20 percent. The ordering of additional units in the same series will not lead to significantly more cost savings. The standardisation effect for more than two units of identical design is expected to be negligibly low.

When the UK Performance and Innovation Unit (PIU) of the Cabinet Office examined nuclear power economics in 2002, it was provided with forecasts of costs from British Energy (the nuclear power plant owner) and BNFL (the plant vendor) that were based on "a substantial learning and scale effects from a standardised programme." The PIU was skeptical about the extent of learning, acknowledging that learning was likely to occur but that its impact could be limited. It stated:[12]

> The pace and extent of learning may however be slower for nuclear than for renewables because:
>
> - relatively long lead times for nuclear power mean that feedback from operating experience is slower;
> - relicensing of nuclear designs further delays the introduction of design changes; and
> - the scope for economies of large-scale manufacturing of components is less for nuclear because production runs are much shorter than for renewables, where hundreds and even thousands of units may be installed.

The major reactor vendors have received only a handful of orders in the past 20 years, their own production lines have closed, and skilled teams have been cut back. Westinghouse had received only one order in the past 25 years before the order for four units from China in 2008. Even the French vendor Areva received its first order in about 15 years with its order for Finland. For new orders, large components would generally have to be subcontracted to specialist companies and built on a one-off basis, presumably at higher costs in countries such as Japan and, for the future,

11 Nuclear Energy Agency, *Reduction of Capital Costs of Nuclear Power Plants* (Paris: OECD, 2000), p. 90.
12 Performance and Innovation Unit, *The Energy Review*, Cabinet Office (London: 2002), p. 195, http://www.strategy.gov.uk/downloads/su/energy/TheEnergyReview.pdf.

China.[13] There are now acknowledged to be major shortages in component manufacturing facilities. For example, by the end of 2009, only one facility in the world, Japan Steel Works, could cast large forgings for certain reactor pressure vessels.

Skills shortages are also becoming acute. A report for the German Environment Ministry stated:[14]

> The nuclear skills and competence gap is an internationally well established and recognized problem. Numerous initiatives have been launched on national and international scale in order to reverse the trend. However, apparently, the results remain far short of the necessary employment levels for all stakeholders involved. The number of nuclear graduates and technicians is insufficient and many graduates do not enter or quickly leave the nuclear sector. In-house training only partially compensates for the problem since the nuclear industry has to compete in a harsh market environment with many other sectors that lack scientists, engineers and technicians.

3.1.4. Construction time

An extension of the construction time beyond that forecast does not directly increase the construction costs, although it will tend to increase IDC and often is a symptom of problems in the construction phase such as design issues, site management problems, or procurement difficulties that will be reflected in higher construction costs. However, the impact on the utility – if it is a relatively small utility for which the new plant would represent a major addition to capacity – could be severe, especially if the output is already contracted.

The Olkiluoto plant was expected to come on-line in May 2009 when the construction contracts for it were signed. However, by May 2009, the plant was still nearly four years from completion. Its output had already been contracted to the Finnish energy-intensive industry. So, the utility will have to buy “replacement power” to supply its customers with the power they had contracted from the Nordic wholesale electricity market until the plant is complete, at whatever cost is prevailing in the Nordic market. If the supply-demand balance is tight, for example if there is a dry winter that restricts the amount of hydroelectricity availability, this cost could be far higher than the contracted sale price. The utility is unlikely to be able to absorb losses for long if the Nordic market price is significantly higher than the price at which it had contracted to sell the output of Olkiluoto for.

Overall lead time – from the time of the decision to build the plant to its commercial operation (i.e., after the initial testing of the plant has been completed and its operation handed over by the vendor to the owner) – is generally much longer than the construction time. For example, the decision to

13 For example, if the Flamanville EPR is ordered, the pressure vessel would probably be manufactured in Japan.

14 M. Schneider, S. Thomas, A. Froggatt, and D. Koplow, *World Nuclear Industry Status Report 2009*, German Federal Ministry of Environment, Nature Conservation and Reactor Safety (2009), http://www.bmu.de/files/english/pdf/application/pdf/welt_statusbericht_atomindustrie_0908_en_bf.pdf.

build the Sizewell B nuclear power plant in Britain was taken in 1979, but construction did not start until 1987 (because of delays not only from a public inquiry but also from difficulties in completing the design). The plant only entered commercial service in 1995, so the total lead-time was 16 years. The cost of the preconstruction phase is generally relatively low compared to construction, unless the reactor is the "first-of-a-kind," where design and safety approval could prove expensive. However, for a generating company operating in a competitive environment, this long delay and the risks it entails – such as failure at the planning inquiry stage or cost escalation from regulatory requirements – is a major disincentive to choose nuclear.

3.2. Cost of capital

This is the other element – construction cost in capital charges (see Appendix 2). Generally, large projects are financed through a combination of debt (borrowing from banks) and equity (self-financing from income). For debt, the cost of capital will depend on the prevailing "risk-free" interest rate, for example, the rate paid by treasury bonds, plus a risk factor to represent the degree of risk involved in the project, plus of course the bank's margin and costs.

For equity, it is often suggested that large companies with substantial resources can easily pay for large investments from income with little need for borrowing. However, essentially by financing investment from equity, the company is asking shareholders to defer sums that could have been paid immediately as dividends. This money will be invested in the project and, in the long-term, will be paid back to the shareholders as profits from the project. To compensate the shareholders for the delay in receiving their income, the company must pay the interest that shareholders could have earned if they had been paid the money and invested it in low-risk investments plus a premium to reflect the risk that is being taken with their money (the project might not make the return on investment it was expected to). The cost of equity is therefore generally higher than the cost of debt.

If banks are unwilling to lend, replacing borrowing with equity is not likely to be an option. Essentially this would mean a company was asking its shareholders to lend money to the company for a project the banks would not touch. Shareholders may therefore oppose funding of large projects with too large an element of equity funding. Equally, banks will not look kindly on loan applications if it seems the company is not prepared to risk its own money.

It is particularly revealing that in the United States, when the Nuclear Power 2010 program was launched, it was expected that projects would be financed in equal measure by debt and equity. By 2008, it was clear that the companies were expecting to cover as much of the project cost by borrowing as possible – backed by federal loan guarantees . The banks also strongly stated they would be willing to lend money only if the coverage by loan guarantees was very comprehensive.

As noted in Section 4, six of Wall Street's largest investment banks informed the US DOE that they were unwilling to extend loans for new nuclear power plants unless taxpayers shouldered 100 percent of the risks.[15]

The real (net of inflation) cost of capital varies from country to country and from utility to utility, according to the country-risk and the credit-rating of the company. There will also be a huge impact from the way in which the electricity sector is organized. If the sector is a regulated monopoly, the real cost of capital could be as low as 5 to 8 percent, but in a competitive electricity market, it is likely to be at least 15 percent. Thus, for Florida and Georgia, for example, where the regulator is allowing the utilities to begin to recover the cost of new nuclear power plants in regulated electricity tariffs even before construction starts, the utility is less dependent on loan guarantees being offered to borrow money at low rates. The Georgia Public Service Commission accepted Georgia Power's, which owns 45.7 percent of the Vogtle project, request to recover its financing costs for its $6.4 billion share of the 2234-MW nuclear project through "construction work-in-progress" beginning in 2011.[16] The assurance of cost recovery means that the owners have claimed it will proceed with construction even if it does not receive loan guarantees. It has also reduced the expected cost of Georgia Power's share, including financing up to $4.529 billion.[17]

It is clear that if the largest element of cost in power from a nuclear power plant are the capital charges, more than doubling the required rate of return will severely damage the economics of nuclear power. There is no "right" answer about what cost of capital should be applied. When the electricity industry was a monopoly, utilities were guaranteed full cost recovery. In other words, whatever money they spent, they could recover from consumers. This made any investment a very low risk to those providing the capital because consumers were bearing all the risk. The cost of capital varied according to the country and whether the company was publicly or privately owned. Publicly owned companies like Vattenfall, the Swedish state-owned utility, generally have a high credit rating and therefore the cost of capital is lower for them than for companies partly or wholly owned by private shareholders, like the two main German utilities, E.ON and RWE. For publicly owned companies, shareholder pressure was also generally less than for shareholder companies, and using equity might have been easier. The real cost of capital – that is, the annual interest rate for borrowing, net of inflation – for a developed country was generally in the range of 5 to 8 percent.

In an efficient electricity market, the risk of investment would fall on the generation company, not the consumers, and the cost of capital would reflect this risk. For example, in 2002 in Britain, about

15 Investors' comments in response to DOE notice of proposed rulemaking, July 2, 2007.

16 Platts Global Power Report, *Georgia PSC Approves Two Nuclear Reactors by Georgia Power, and a Biomass Conversion*, March 19, 2009.

17 *Nucleonics Week*, "Georgia Power Lowers Estimate for New Vogtle Units," November 11, 2009.

40 percent 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 more than 15 percent seems well-justified. If the risks were reduced – for example if there were government guarantees on the market for power and the price – the cost of capital would be lower, but these would represent a government subsidy (state aid) and it is not clear they would be acceptable under European Union law.

3.3. Operating performance

For a capital-intensive technology like nuclear power, high utilization is of great importance, so that the large fixed costs (repaying capital, paying interest, and paying for decommissioning) can be spread over as many saleable units of output as possible. In addition, nuclear power plants are physically inflexible and it would not be wise to start up and shut down the plant or vary the output level more than is necessary. As a result, nuclear power plants are operated on “base load,” 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.[18] Generally, load factors are calculated on an annual or a lifetime basis. Unlike construction cost, the load factor can be precisely and unequivocally measured and load factor tables are regularly published by the trade press such as *Nucleonics Week* and *Nuclear Engineering International* as well as by the International Atomic Energy Agency (IAEA). There can be dispute about the causes of shutdowns or reduced output levels, although from an economic point of view, the fact that output is not being produced is of less importance than why it is not being produced.

Table 6. Operating performance of German nuclear power plants

Plant	Commercial operation	Load factor 2008 (%)	Lifetime load factor to end of 2008 (%)
Biblis A	2/1975	82.6	65.2
Biblis B	1/1977	95.2	67.7
Brokdorf	12/1986	92.4	88.5

18 Note that where reactors are derated, some organizations (e.g., the IAEA) quote the load factor on the authorized output level rather than the design level. While this may give some useful information on the reliability of the plant, for economic analysis purposes, the design rating should be used because that is what the purchaser paid to receive.

Brunsbüttel	2/1977	0.0	53.7
Emsland	6/1988	93.3	93.3
Grafenrheinfeld	6/1982	87.2	86.2
Grohnde	2/1985	88.3	90.6
Gundremmingen B	7/1984	85.7	82.6
Gundremmingen C	1/1985	87.7	80.4
Isar 1	3/1979	98.3	79.3
Isar 2	4/1988	93.2	89.6
Krümmel	3/1984	0.0	71.6
Neckarwestheim 1	12/1976	54.9	79.5
Neckarwestheim 2	4/1989	93.0	92.7
Philippsburg 1	3/1980	78.4	79.0
Philippsburg 2	4/1985	88.7	88.2
Unterweser	9/1979	78.7	79.6

Source: IAEA, http://www.iaea.or.at/programmes/a2/

Note: The Krümmel and Brunsbüttel plants were closed for the whole of 2008.

Table 6 shows the 2008 and the lifetime load factors for German nuclear power plants. It shows a wide range of reliability with three plants having a lifetime load factor of more than 90 percent, while three units have a lifetime load factor of less than 70 percent.

As with construction cost, load factors of operating plants have been much lower than forecast. The assumption by vendors and those promoting the technology has been that nuclear plants are extremely reliable, with the only interruptions to service being for maintenance and refueling (some designs of plant such as the AGR and Candu are refueled continuously and need to only shut down for maintenance), thereby giving a load factors of 85 to 95 percent. However, performance was poor and in around 1980, the average load factor for all plants worldwide was about 60 percent. 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 percent, then the overall cost would go up by a third if the load factor was only 60 percent. To the extent that poor load factors are caused by equipment failures, the additional cost of maintenance and repair resulting would further increase the unit cost of power. In a competitive market, a nuclear generator contracted to supply power that is unable to fulfill its commitment is likely to have to buy the “replacement” power for its customer, potentially at very high prices.

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 percent and, for example, the United States now has an average of nearly 90 percent compared to less than 60 percent in 1980, although the average lifetime load factor of America's nuclear power plants is still only 70 percent.

Only seven of the 414 operating reactors with at least a year's service and that have full performance records have a lifetime load factor in excess of 90 percent, and only the top 100 plants have a lifetime load factor of more than 80 percent. Interestingly, the top 13 plants are sited in only three countries: six in South Korea, five in Germany, and two in Finland.

New reactor designs may emulate the level of reliability achieved by the top 2 percent 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 poignant. 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. 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 in line with current standards of safety. This decline in performance will probably not weigh very heavily in an economic analysis because of discounting. Overall, an assumption that reliability of 90 percent or more seems hard to justify on the basis of past experiences.

3.4. Non-fuel operations and maintenance cost

Many people assume that nuclear power plants are essentially automatic machines requiring only the purchase of fuel and have very low running costs. As a result, the non-fuel operations and maintenance (O&M) costs are seldom prominent 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 (excluding repaying the fixed costs) was found to be greater than the 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, while fuel costs were then more than \$12/MWh.[19] 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 and fuel costs to \$4.5/MWh. However, it is important to note that these cost reductions were achieved mainly by improving the reliability of the plants rather than actually

19 For statistics on O&M costs, see http://www.nei.org/index.asp?catnum=2&catid=95.

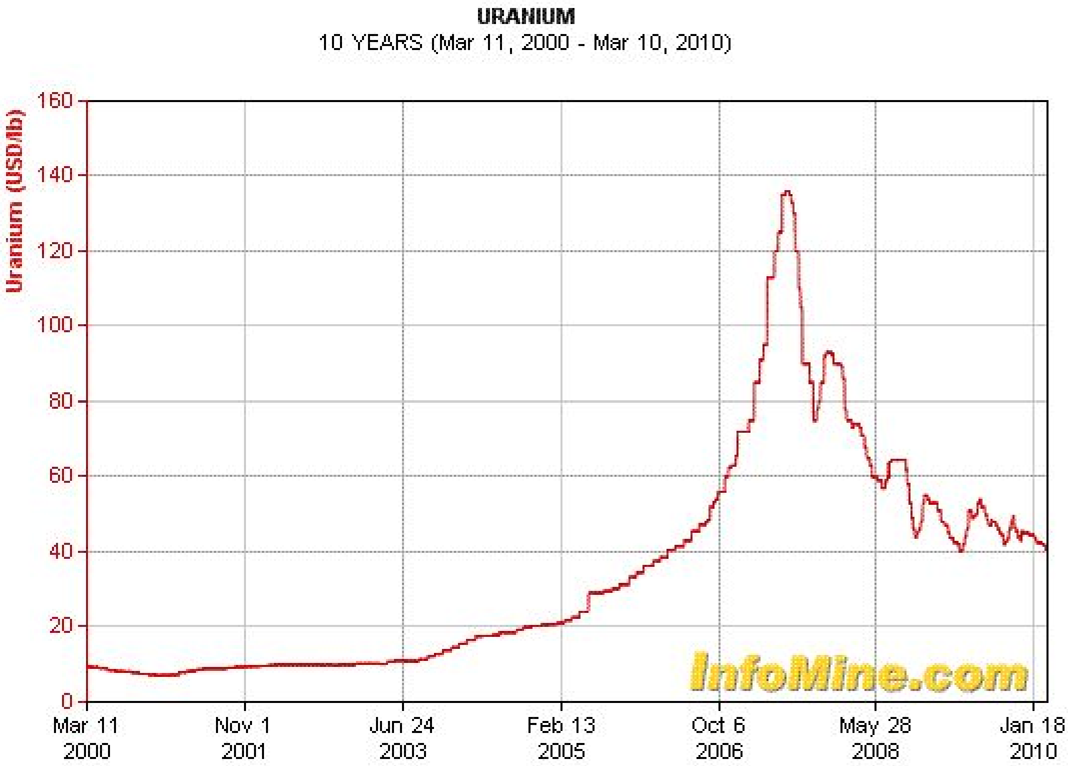
reducing costs. Many O&M costs (the cost of employing the staff and maintaining the plant) are largely fixed and vary little according to the level of output of the plant. So, the more power that is produced, the lower the O&M cost per MWh. The threat of early closure on grounds of economics has now generally been lifted in the United States.

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). Average O&M costs for British Energy's eight plants, including fuel, varied between about 1.65-2.0p/kWh from 1997–2004. However, in every following year, the operating costs increased. In the last full year for which data was published, 2007/08, the cost was 3p/kWh and in the first six months of 2008/09, the cost was 4.13p/kWh (the company was taken over then by the French utility, EDF, and operating cost figures are not published).

3.5. Fuel cost

The cost of fuel, about 5 percent of the total cost of power, includes the cost to mine the uranium, "enrich" it (increase the percentage of the useful uranium isotope), fabricate it into fuel, store it after use, and dispose of it in a safe repository, where it must remain isolated from the environment for several hundred thousand years. The costs other than the purchase cost of fuel are not discussed further here. Fuel costs have fallen as the world uranium price was low from the mid-1970s (around $12/lb of U_3O_8) to around 2000, after which prices rose to about $150/lb (see Table 7). Subsequently, spot prices fell to less than $50/lb by the end of 2009. These spot prices are a little misleading as the spot market is very "thin" and only a small proportion of uranium is bought and sold on this market, with the vast majority being sold under long-term bilateral contracts. US fuel costs average about 0.25p/kWh, 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 (0.06p/kWh). 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 United States or anywhere else – and all the US spent fuel remains in temporary storage pending the construction of a spent-fuel repository, expected to be at Yucca Mountain. Real disposal costs are likely to be much higher.

Table 7. Price of uranium



Source: http://www.infomine.com/investment/charts.aspx?mv=1&f=f&r=10y&c=curanium.xusd.ulb#chart, 2010-03-11

The issue of spent-fuel disposal is difficult to evaluate. Reprocessing is expensive and, unless the plutonium produced can be profitably used, it does nothing 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. 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 per year, which equates to about 0.5p/kWh. The new contract is expected to save British Energy about £150–200 million per year, although this will be possible only because of underwriting of losses at BNFL by the government. Despite this poor cost experience, the United States was reported to be considering allowing the reprocessing of spent fuel, which has not occurred since a ban was imposed by the Carter administration. 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 must have a very wide margin for error.

3.6. Accounting lifetime

One of the features of Generation III+ plants compared to their predecessors is that they are designed to have a life of about 60 years compared to their predecessors, which 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 more time 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 (see Appendix 2).

There is a trend of extending the life of existing plants. Some PWRs and BWRs that are now reaching their original licensed lives of 40 years are being licensed by the US safety authorities for a further 20 years of operation. However, it should not be assumed that there will be cheap electricity once capital costs have been repaid. Life extension may require significant new expenditures to replace worn-out equipment and to bring the plant in compliance with current safety standards. Life extension is not always possible. For example, Britain's AGRs, which had a design life of 25 years, are now expected to run for 40 years, but life extension beyond that may not be possible because of problems with erosion and distortion of the graphite moderator blocks.

3.7. Decommissioning and waste disposal cost and provisions

These are difficult to estimate because there is little experience with decommissioning commercial-scale plants and the cost of disposal of waste (especially intermediate or long-lived waste) is uncertain (see Appendix 3). However, even schemes that 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 percent to the construction cost. The British Energy segregated fund, which did not cover the first phase of decommissioning, required contributions of less than £20m per year, equating to a cost of only about 0.03p/kWh.

The problems come if the cost has been initially underestimated, the funds are lost, or the company collapses before the plant completes its expected lifetime. All of these problems have been experienced in Britain. The expected decommissioning cost has gone up several-fold in real terms over the past couple of decades. In 1990, when the Central Electricity Generating Board (CEGB) was privatized, the accounting provisions made from contributions by consumers were not passed on to the successor company, Nuclear Electric. The subsidy that applied from 1990 to 1996 – described by Michael Heseltine[20] 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 treasury. The collapse of British Energy has meant that a significant proportion of their decommissioning costs will be paid by future taxpayers.

20 Michael Heseltine, President of the Board of Trade, Hansard, October 19, 1992.

3.8. Insurance and liability

This is a controversial area because at present, the liability of plant owners is limited by international treaty to only a small fraction of the likely costs of a major nuclear accident. The Vienna Treaty, passed in 1963 and amended in 1997, limits a nuclear operator's liability to 300 million Special Drawing Rights or about $460 million (on Feb 22, 2009, US$1=0.653SDR[21]). At present the British government underwrites residual risk beyond £140 million, though the limit is expected to rise under the Paris and Brussels Conventions to €700 million (£500m). The limit on liability was seen as essential to allow the development of nuclear power but can also be seen as a large subsidy.

Table 8. Liability limits for the OECD countries as of September 2001

	Liability limits under national legislation[a]	Financial security requirements[a,b]
Belgium	€298m	
Finland	€250m	
France	€92m	
Germany	unlimited	€2,500m[c]
Great Britain	€227m	
Netherlands	€340m	
Spain	€150m	
Switzerland	unlimited	€674m
Slovakia	€47m	
Czech Republic	€177m	
Hungary	€143m	
Canada	€54m	
USA	€10,937m	€226m
Mexico	€12m	
Japan	unlimited	€538m
Korea	€4,293m	

Source: Unofficial Statistics – OECD/NEA, Legal Affairs

Notes: [a] using official exchange rates June 2001–June 2002; [b] if different than the liability limit; [c] €256m insurance, €2.5bn operator's pool, €179m from Brussels amendment to Paris Convention.

21 The value of the Special Drawing Right is determined by a basket of the world's four major currencies.

The German parliament's Study Commission on Sustainable Energy[22] compiled figures on the liability limits in OECD countries (see Table 8) and this 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 on the order of hundreds of billions of pounds (it is invidious to put a cost on the value of loss of life or incapacity but for insurance purposes it is necessary), 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.

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 losses 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.

4. Experience at Olkiluoto and Flamanville

These two plants are of particular importance because they are the only Generation III+ plants for which there is any significant experience, albeit for construction only, not operation.

4.1. Olkiluoto

The Olkiluoto-3 order for Finland was seen as particularly important for the nuclear industry because it seemed to contradict the conventional wisdom that liberalization and nuclear power orders were incompatible. The Olkiluoto-3 reactor order of December 2003 was the first nuclear order in Western Europe and North America since the 1993 Civaux-2 order in France and the first order outside the Pacific Rim for a Generation III/III+ design. The Finnish electricity industry had been attempting to obtain parliamentary approval for a fifth nuclear unit in Finland since 1992. This was finally granted in 2002. The Olkiluoto-3 order was a huge boost for the nuclear industry in general, and Areva NP in particular. Industry anticipated that, once complete, the plant would provide a demonstration and reference for other prospective buyers of the EPR.

22 Deutscher Bundestag, *Nachhaltige Energieversorgung unter den Bedingungen der Globalisierung und Liberalisierung*, Bericht der Enquete-Kommission, zur Sache 6/2002, chapter 3.3.2, table 3.3 (Berlin: Deutscher Bundestag, 2002), p. 232, http://dip.bundestag.de/btd/14/094/1409400.pdf.

Finland is part of the Nordic electricity market covering also Norway, Sweden, and Denmark. The region is generally seen as the most competitive electricity market in the world. Finland also has a good reputation for the operation of the four units located in the country. So there were high hopes that this would answer many of the questions concerning the “nuclear renaissance.” However, closer examination of the deal reveals some very special features that show this deal is not representative of conditions in other markets.

The contract price for Olkiluoto-3 was reported in 2004 to be €3 billion for a 1600 MW plant.[23] Subsequently, the price was reported to be €3.2 billion[24] or €3.3 billion.[25] Safety approval was given by the Finnish regulator, STUK, in March 2005 and substantive work on-site started in August 2005. At the time the contract was signed, the value was equivalent to about $3.6–4.0 billion (depending on the contract price) or about $2,250–2,475/kW (€1=US$1.2). This cost included financing and two reactor cores and so the cost per kW in overnight terms would have been somewhat lower, although given – as we can see below – the very low rate of interest charged (2.6%), finance costs would be low.

Although this cost was well above the nuclear industry’s target of $1,000/kW of only a few years before, it was still regarded by critics as a “loss-leader.” Areva NP had been trying to persuade either EDF or one of the German utilities to place an order for an EPR since the late 1990s[26] and there were fears that if an order for the EPR was not placed soon, AREVA NP would start to lose key staff[27] and the design would become obsolete.[28] AREVA NP also needed a “shop window” for EPR technology and Olkiluoto-3 would serve as a reference plant for other orders. As an additional incentive and at the request of the customer, AREVA NP offered the plant on “turnkey” or fixed price terms. It also took responsibility for the management of the site and for the architectural engineering, not just the supply of the “nuclear island.” This was not a role it was accustomed to. For the 58 PWRs, Areva NP’s predecessor, Framatome, had supplied for France, as well as for the foreign projects including those in China and South Africa; it was EDF that had provided these services.

23 Project Director Martin Landtman stated: “The value of the whole Olkiluoto 3 investment including the Turn-key Contract is about EUR 3 billion in year 2003 money. No other figures are published”; personal communication, e-mail to Mycle Schneider, dated October 8, 2004.

24 *Nucleonics Week*, “EC Probing Claims Olkiluoto Loan Guarantees Were State Aid,” October 26, 2006.

25 *Nucleonics Week*, “Areva Reveals 47% Cost Overrun on Contract for Olkiluoto-3,” March 5, 2009, p 1.

26 *Nucleonics Week*, “Giant EPR Said To Be Competitive: EDF To Decide on Order Next Year,” November 6, 1998, p 1.

27 *Petroleum Economist*, “France Mulls Nuclear Future,” March 2001.

28 *Nucleonics Week*, “EPR Safety Approval Won’t Last Beyond 2002, Regulator Warns,” March 6, 1997.

As has been documented elsewhere,[29] the Olkiluoto project has gone seriously wrong since construction started. By March 2009[30] the project was acknowledged to be at least three years late and €1.7 billion over budget.[31] In August 2009, Areva NP acknowledged that the estimated cost had reached €5.3 billion, which at the prevailing exchange rate of €1=US$1.35 represented a cost of $4,500/kW.[32] The contract is also the subject of an acrimonious dispute between Areva NP and the customer, Teollisuuden Voima Oy (TVO). Areva NP is claiming compensation of about €1 billion for alleged failures of TVO. TVO, in a January 2009 counterclaim, is demanding €2.4 billion in compensation from Areva NP for delays in the project.[33]

It seems unlikely that all the problems that have contributed to the delays and cost-overruns have been solved; the final cost could be significantly higher. The result of the claim and counter-claim arbitration between Areva NP and TVO will determine how the cost-overrun will be apportioned. Regardless, however, it is clear that investor concerns on plant costs and delivery remain valid.

4.2. Flamanville

EDF finally ordered an EPR reactor in January 2007, to be located at their Flamanville site. This reactor was uprated to 1630 MW[34] and construction commenced in December 2007.[35] In May 2006, EDF estimated the cost would be €3.3 billion.[36] At that time (€1=US$1.28), this was equivalent to $2,590/kW. This cost, however, did not include the first fuel, so the overnight cost would have been somewhat higher. The cost estimate did not include financing either.

EDF did not seek a turnkey contract that carried out the architectural engineering and managed the contracting – for example letting contracts – for the turbine generator. How far these decisions were influenced by the poor experience at Olkiluoto and how far they were influenced by the need it saw to maintain in-house skills is not clear.

In May 2008, the French safety regulatory authorities temporarily halted construction at Flamanville because of quality issues in pouring the concrete base mat.[37] Delays had led the vendor, Areva NP, to forecast the plant would not be completed until 2013, a year late. But in November

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29 S. Thomas, "Can Nuclear Power Plants Be Built in Britain without Public Subsidies and Guarantees?", Presentation at a conference, *Commercial Nuclear Energy in an Unstable, Carbon Constrained World,* co-hosted by the Nonproliferation Policy Education Center and Radio Free Europe/Radio Liberty, March 17–18, 2008, Prague, Czech Republic.

30 *Nucleonics Week*, "Areva's Olkiluoto-3 Manager Says Engineering Judgment Undermined," March 26, 2009, p. 4.

31 *Nucleonics Week*, "Areva Reveals 47% Cost Overrun."

32 *Nucleonics Week*, "With Expected Losses Mounting, Areva Seeks Changes in Ol3 Project," September 3, 2009.

33 *Agence France Presse*, "Setbacks Plague Finland's French-built Reactor," January 30, 2009.

34 *Nucleonics Week*, "EDF Orders Flamanville-3 EPR NSSS, with Startup Targeted in 2012," January 5, 2007, p. 1.

35 *Nucleonics Week*, "Flamanville-3 Concrete Pour Marks Start of Nuclear Construction," December 6, 2007, p. 3.

36 *Nucleonics Week*, "EDF to Build Flamanville-3, Says First EPR Competitive with CCGT," May 11, 2006, p. 1.

37 *Nucleonics Week*, "Concrete Pouring at Flamanville-3 Stopped after New Problems Found," May 29, 2008, p. 18.

2008, EDF claimed the delays could be made up and the plant finished to the original schedule of 2012.[38] EDF did acknowledge that the expected construction costs for Flamanville had increased from €3.3 billion to €4 billion.[39] This was then equivalent (€1=US$1.33) to $3,265/kW, substantially more than the Olkiluoto contract price, but far below the levels being quoted in the United States and the actual cost of Olkiluoto. There have also been claims by the trade unions involved that construction at Flamanville is running at least two years late.[40] An Areva official has suggested that the cost of an EPR will now be at least €4.5 billion, although it was not specified whether this was an overnight cost.[41]

5. The US program

The Bush administration made a concerted effort to revive nuclear ordering under its Nuclear Power 2010 program, announced in February 2002. The program focuses on Generation III+ designs. When it was announced, it was expected that at least one Generation III+ unit and one reactor of a more advanced design would be in operation by 2010. Under the program, the US Department of Energy (USDOE) expected 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 and operate a new nuclear power plant.[42]

In addition:

> […] to complete the first-of-a-kind Generation III+ reactor technology development and to demonstrate the untested Federal regulatory and licensing processes for the siting, construction, and operation of new nuclear plants.[43]

The rationale for the Nuclear Power 2010 program was that the new nuclear designs would be economically competitive. However, bad experience with building nuclear plants in the United States in the 1980s and 1990s meant that utilities would be reluctant to order nuclear plants until it

38 *Nucleonics Week*, "EDF Confirms Target of Starting Up Flamanville-3 in 2012," November 20, 2008, p. 1.
39 *Associated Press Worldstream*, "EDF To Lead up to Euro50b in Nuclear Plant Investment," December 4, 2008.
40 *Nucleonics Week*, "French Union: Flamanville-3 Delayed," January 28, 2010, p. 1.
41 *Nucleonics Week*, "Areva Official Says Costs for New EPR Rising, Exceeding $6.5 billion," September 4, 2008, p. 1.
42 http://www.ne.doe.gov/NucPwr2010/NucPwr2010.html.
43 United States Department of Energy (DoE), *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010* (Washington, DC: USDOE, 2001).

had been fully demonstrated that the new designs and procedures resolved the issues that had led to these problems. The policy to overcome these barriers was therefore to streamline regulatory processes, ensure regulatory approval for a number of new designs, and provide subsidies initially for three projects (perhaps six units), after which ordering would require no subsidies.

A total of up to $450 million in grants was initially proposed for at least three projects. Three main organizations emerged to take advantage of these subsidies, with two signing agreements with the USDOE to develop COLs. Nustart, launched in 2004, was made up of a consortium of eight US utilities, including Entergy, Constellation Energy, 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 were also members but had no voting rights. Nustart planned to make two applications, one for a GE ESBWR at Entergy's Grand Gulf (Texas) site and one for a Westinghouse AP1000 at TVA's Bellefonte site. The other main group is led by the utility Dominion. Dominion was seeking a COL for an advanced version of Atomic Energy of Canada's Candu design, the ACR-700, at North Anna (Virginia), where Dominion operates two reactors. However, in January 2005, it announced that it had replaced the ACR-700 with GE's ESBWR because of the expected time for a Candu plant to be licensed in the United States. A Candu design has not achieved regulatory approval in the United States and the NRC forecast that its approval process could take more than 60 months – much longer than it then expected would be required for a Generation III+ PWR or BWR. Subsequently, it has become clear that all the new designs being assessed by the NRC will take more than 60 months to assess.

Since the Energy Policy Act of 2005 (EPACT), the timescale of the program has slipped but the scope has expanded to accommodate the large number of US utilities expressing an interest in building plants, and the scale of support on offer has also increased dramatically. By the start of 2009, plans to build 31 units had been announced (see Table 9).

A package of subsidies was later proposed for this handful of demonstration units, of which two have turned out to be the most important:

- **Production Tax Credits**: In order to make electricity generated from new nuclear power plants competitive with other sources of energy, an $18/MWh tax credit would be paid for the first eight years of operation. According to the Energy Information Administration (EIA), this subsidy would cost US taxpayers $5.7 billion by 2025.[44]

44 United States Department of Energy (DoE), *Analysis of Five Selected Tax Provisions of the Conference Energy Bill of 2003* (Washington, DC: Energy Information Administration, 2004), p. 3, http://tonto.eia.doe.gov/FTPROOT/service/sroiaf(2004)01.pdf.

- **Loan Guarantees:** To ease the difficulty of financing new plants, loan guarantees were offered so that utilities could borrow at government treasury bond rates. The Congressional Budget Office concluded that the risk for loan default by the industry would be “well above 50 percent.”[45] The Congressional Research Service estimated that the taxpayer liability for loan guarantees covering up to 50 percent of the cost of building six to eight new reactors would be $14–16 billion.[46]

Table 9. US nuclear projects announced under “Nuclear Power 2010”

Plant	Owner	NRC Status	Loan guarantee	Design	Expected on-line
Calvert Cliffs 3	Unistar	COL application submitted 3/08	Short-listed	EPR	?
South Texas 3,4	NRG	COL application submitted 9/07	Short-listed	ABWR	?
Bellefonte 3,4	TVA	COL application submitted 10/07	Not eligible	AP1000	?
North Anna 3	Dominion	COL application submitted 11/07	Applied	ESBWR	?
Lee 1,2	Duke	COL application submitted 12/07	Applied	AP1000	2021–23
Harris 2,3	Progress	COL application submitted 2/08	Not applied	AP1000	2019–20
Grand Gulf 3	Entergy	COL application submitted 2/08	Applied	ESBWR	Suspended
Vogtle 3,4	Southern	COL application submitted 3/08	Short-listed	AP1000	2016
Summer 2,3	SCANA	COL application submitted 3/08	Short-listed	AP1000	2016–19
Callaway 2	AmerenUE	COL application submitted 7/08	Applied	EPR	Suspended
Levy 1,2	Progress	COL application submitted 7/08	Applied	AP1000	2019–20
Victoria 1,2	Exelon	COL application submitted 9/08	Applied	ESBWR	Suspended
Fermi 3	DTE Energy	COL application submitted 9/08	Not applied	ESBWR	?
Comanche Peak 3,4	TXU	COL application submitted 9/08	First reserve	APWR	?
Nine Mile Point 3	Unistar	COL application submitted 10/08	Applied	EPR	Suspended
Bell Bend	PPL	COL application submitted 10/08	Applied	EPR	2018
Amarillo 1,2	Amarillo	?		EPR	?
River Bend	Entergy	COL application submitted 9/08	Applied	ESBWR	Suspended
Elmore	Unistar	?		EPR	Suspended

45 Congressional Budget Office, *Cost estimate of S.14, Energy Policy Act of 2003* (Washington, DC: Congressional Budget Office, May 7, 2003), http://www.cbo.gov/doc.cfm?index=4206.

46 Congressional Research Service (CRS), *Potential Cost of Nuclear Power Plant Subsidies in S.14* (May 7, 2003); requested by Senator Ron Wyden.

Turkey Point 6,7	FPL	COL application planned 3/09	?	AP1000	2018–20

Source: Various press reports

Notes: More details on the individual projects is available in Appendix 4.

EPACT offered up to $500 million in risk insurance for units 1–2 and $250 million for units 3–6. This insurance would be paid if delays not attributable to the licensee slowed licensing of the plant. It also offered support for R&D funding worth $850 million and help with historic decommissioning costs worth $1.3 billion.

It soon became clear that the loan guarantees were not only the key element of the package, but that the extent of coverage offered was insufficient to allow utilities to place orders. Federal loan guarantees were originally expected to cover up to 80 percent of the debt involved in the project and if debt accounted for about 60 percent of the cost of building the plant (the rest from equity), this would mean about half the cost of the plant would be covered. Utilities successfully lobbied for 100 percent coverage of debt up to 80 percent of the project cost. Banks were also vocal in their call for full coverage. A statement in 2007 signed by six of Wall Street's largest investment banks (Citigroup, Credit Suisse, Goldman Sachs, Lehman Brothers, Merrill Lynch, and Morgan Stanley) informed the USDOE that they were unwilling to extend loans for new nuclear power plants unless taxpayers shouldered 100 percent of the risks.[47]

In states where the electricity market is less liberalized and utilities operating under regulated tariffs with a regulated asset base, loan guarantees may be less vital. If regulators agree, as some have, in advance of completion of the plant to allow the utility to begin to recover the construction cost of the plant, there will be a significant shift in the construction risks away from the utility to the consumers. This may mean financiers will offer loans at a much lower rate than if the plant had to compete in a market.

The scope of the subsidies also grew, going from covering just three sites (up to six units) to loan guarantees for up to three units of each "innovative" design, and by 2008, five qualifying "innovative designs" were being processed by the Nuclear Regulatory Commission (NRC). This meant up to 15 units would be eligible for loan guarantees. The five designs are: Westinghouse AP1000; GE-Hitachi ESBWR; GE-Hitachi ABWR[48]; Areva NP EPR; and Mitsubishi APWR.

In 2002, when the program was launched, construction costs of $1,000/kW were still expected, and the guarantees needed for six units of about 1400 MW, each covering 50 percent of the total cost, would have been about $4.2 billion. But in 2008, if we assume 15 units will be eligible and will be

47 Investors' comments in response to DOE notice of proposed rulemaking, July 2, 2007.
48 Toshiba may also offer the ABWR independently from GE-Hitachi.

covered up to 80 percent of their total cost of $6,000/kW, guarantees worth in excess of $100 billion would be required.

The Energy Bill passed in 2007 gave the USDOE a budget of up to $18.5 billion for 2008/09 for loan guarantees covering nuclear plants. The USDOE short-listed five projects for these loan guarantees in February 2009. These were Southern Company (Vogtle), South Carolina Electric & Gas (Summer), Unistar Nuclear Energy (Calvert Cliffs), NRG (South Texas), and the Comanche Peak project. The list was subsequently reduced to four projects when the Comanche Peak project was relegated to first reserve in May 2009. Appendix 4 gives a detailed description of the status of the announced nuclear projects in the United States.

5.1. Likely outcomes

While reactor designs are being reviewed by the NRC, all raise significant questions. The APWR has been close to commercial order in Japan for about a decade, but for reasons that are not clear, the order has not materialized. In the United States, it has only one customer, and if that project should not proceed and the Japanese order continues to be delayed, the technology would seem to have little future.

There is little interest in the ESBWR outside the United States, and since 2008 it has lost three out of five of its US customers. These customers have made damaging comments about the uncertainty of construction costs and how close to commerciality the design is. The remaining two customers for the ESBWR (Dominion and DTE Energy) are not on the short-list for loan guarantees. If these orders fall through, it will be hard for the ESBWR to survive; if they do not, this would raise questions about GE’s future as a reactor vendor.

The ABWR has only one customer (NRG), and that project experienced serious difficulties in late 2009 because of escalating costs. It has the strong advantage of being a demonstrated technology that already has regulatory approval from the NRC. However, this approval runs out in 2012 and any new orders would have to await renewal of its certification. The NRC has yet to give any indication of the extent of any changes that would need to be implemented, for example, on aircraft protection. The ABWR’s advantage as a proven technology will disappear if the list is extensive and the process to review the design-changes is lengthy.

The image of the EPR is being seriously damaged by the problems at Olkiluoto (and Flamanville) and by the difficulty of resolving the control and instrumentation issue with the European safety regulators. Three out of six of its projects appear to be dormant and only the Calvert Cliffs project is well-advanced.

The AP1000 appears to be in the strongest position. It accounts for nearly half of the announced reactor units (14 out of 31) and two out of four of the projects shortlisted for loan guarantees, including the project most likely to get the first of these, Vogtle. None of the AP1000 projects appear to have been abandoned yet, although the TVA Bellefonte project is now in some doubt. It has already received NRC design approval (in 2006) although Westinghouse/Toshiba has subsequently submitted design revisions for which review will not be complete before 2011. Westinghouse/Toshiba is experiencing some difficulty resolving safety issues concerning the end-shield on both sides of the Atlantic. In February 2010, the UK nuclear safety regulator raised a "regulatory issue" on this design aspect.[49]

The existing loan guarantees committed by the US government until the end of 2009 – $18.5 billion – would probably have been consumed by just two projects. There is also the problem of establishing what fee the utilities should have to pay to receive these guarantees. Given that loan guarantees are effectively an insurance policy, the "premium" should reflect the risk of default. The Congressional Budget Office has estimated that the net default risk would be 25 percent (50% but half of the cost would be recovered by selling off equipment). It seems highly improbable that utilities borrowing – say, $10 billion for a two unit project – would be prepared to pay a fee of $2.5 billion just to receive loan guarantees. The utilities are asking for a fee of 1 percent,[50] but this seems unlikely to be politically acceptable.

In February 2010, in its 2011 budget, the Obama administration approved an increase in the amount available for loan guarantees, from $18.5 billion to $54.5 billion (perhaps enough for 12 units).[51] In February 2010, the USDOE announced that loan guarantees worth $8.33 billion had been allocated to the Vogtle (Georgia) project for two AP1000 units.[52] The loan guarantees were expected to cover 7 percent of the costs (at least for the main owner, Georgia Power) although the details of the fee that would be charged for the loan guarantee was not specified. The forecast cost of the plant is therefore about $11.9 billion, or $5,000/kW. The Georgia Public Service Commission had already accepted Georgia Power's request to be allowed to start recovering the construction cost from its monopoly consumers (see Appendix 4). So any bank lending money to the project had double protection: from the federal government (taxpayers) via loan guarantees; and from consumers via guaranteed cost-recovery.

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49 If the regulatory issue is not resolved within a specified time limit (in this case), the safety authorities may refuse to give the design Generic Design Approval; see http://news.hse.gov.uk/2010/02/16/hse-raise-regulatory-issue-ri-against-westinghouses-ap1000-nuclear-reactor-design/.

50 *Electric Utility Week*, "Change to DOE Guarantee Program Boosts Nuclear Hopefuls; Size of Fee Remains an Issue," December 14, 2009.

51 *Associate Press*, "A Look at Obama's 2011 Budget for Gov't Agencies," February 1, 2010.

52 *Washington Post*, "Obama To Help Fund Nuclear Reactors," February 17, 2010.

This model of double protection does show that nuclear plants can be built if the government is prepared to provide large enough subsidies. However, it does not seem likely to be sustainable for more than a few demonstration units, especially if the project does not go smoothly and taxpayers and consumers are forced to meet extra costs.

6. The UK program

The UK government's program is based on very different underlying assumptions than that of the United States. The UK government has never claimed that nuclear power would be directly competitive with fossil fuels, but if a carbon price of €36/ton was assumed, it would be competitive. Ordering would therefore take place without subsidy, provided a few non-financial enabling decisions were taken, particularly on planning processes and certification of designs. In 2008, when the government revisited nuclear economics, its assumed the construction cost was £1,250/kW ($2,000/kW), representing a real increase in costs of about 20 percent over the 2002 figures.[53]

The government's nuclear regulator, the Nuclear Installations Inspectorate (NII), started to examine four separate designs in 2007: the Westinghouse/Toshiba AP1000; the Areva NP EPR; the GE-Hitachi ESBWR; and a Canadian heavy-water reactor design, the ACR-1000 (Advanced CANDU Reactor). The rationale was that up to three designs would be finally certificated, thus giving utilities a choice of designs. Most observers expected that the EPR and AP1000 would be the final choices, and so it has proved. The ACR-1000 was quickly withdrawn and in late 2008, the ESBWR was also withdrawn.

The NII has experienced severe difficulties recruiting sufficient inspectors to carry out its tasks, and in November 2008, it was still 40 inspectors (about 20%) short of the required number. By July 2009, the shortage was 54 inspectors (24%).[54] Some of the utilities operating in the United Kingdom, especially EDF, have said they expect to be able to order plants without subsidies.

However, realistically, orders cannot be placed for at least five years in order to allow regulatory approval for the chosen design and planning approval for a site. Three utilities have made significant commitments to UK ordering: EDF, RWE, and E.ON – the latter two in consortium. EDF took over the UK nuclear generation company, British Energy, for about €15 billion in 2008, while RWE/E.ON have purchased sites in 2009 adjacent to existing nuclear power plants for several hundred million euros. Both EDF and the RWE/E.ON consortium expect to order 4 units, for a total

53 Department for Business, Enterprise and Regulatory Reform, "Meeting the Energy Challenge: A White Paper on Nuclear Power," Cm 7296, HMSO, London, p. 61, http://www.berr.gov.uk/files/file43006.pdf.

54 *Inside NRC*, "UK's NII Short on Inspectors, Sees Years of Recruitment Struggle," July 20, 2009, p. 9.

of 10 to 12 GW of capacity. EDF is expected to order the EPR, while the RWE/E.ON consortium has yet to choose its supplier.

6.1. Likely outcomes

While the 2009 UK government was heavily committed to reviving nuclear ordering in the United Kingdom, there can be no guarantee that when it comes to place orders, the commitment of the government of the day will be so strong. EDF had also heavily committed itself to nuclear ordering in the United Kingdom with its purchase in 2009 of British Energy for about €15 billion. This price seems far above the value of the assets being acquired and only has any logic if new nuclear orders are placed.

British Energy went bankrupt in 2002 because its operating costs, then about £16/MWh, were marginally higher than the price it received for electricity. Since then, operating costs have grown every year and by 2008/09, the operating costs had risen to £41.3/MWh. British Energy only remained solvent because of the extremely high wholesale electricity prices that prevailed in that period – British Energy received £47/MWh in that period. If operating costs continue to rise and/or wholesale electricity prices fall (by the end of 2009, they were well below the 2008 peak), British Energy will be at risk of collapse again. In theory, EDF could simply abandon British Energy (the company was acquired via a wholly-owned subsidiary, Lake Acquisitions) but this would be unlikely to be politically acceptable. The RWE/E.ON consortium had invested a few hundred million pounds in options to buy sites, but if it did not take up these options, it could walk away from a British nuclear program at little cost.

By the start of 2010, the UK was still 3 to 4 years away from completing safety assessments of the designs and getting planning permission for specific sites – the point when a firm order could be placed. At that point, other options, such as renewables and energy efficiency, will most likely not be developed enough to be brought in, and the United Kingdom will be in a position of having to order nuclear plants to keep the lights on. The government will then have to accede to whatever demands the utilities make.

The first major chink in the government’s “no subsidies” policy came in February 2010, when the Energy Minister, Ed Miliband, told the Times:[55]

> The Neta system [the British wholesale market], in which electricity is traded via contracts between buyers and sellers or power exchanges, does not give sufficient guarantees to developers of wind turbines and nuclear plants. He said that one alternative would be a return to “capacity payments” – in which power station operators would be paid for the electricity they

55 The *Times*, “Labour Prepares To Tear Up 12 Years of Energy Policy,” February 1, 2010.

> generate and also for capacity made available. The idea of such payments is to give greater certainty to investors in renewable and nuclear energy.

A day later, the national economic energy regulator announced:[56]

> The unprecedented combination of the global financial crisis, tough environmental targets, increasing gas import dependency and the closure of ageing power stations has combined to cast reasonable doubt over whether the current energy arrangements will deliver secure and sustainable energy supplies […]. There is an increasing consensus that leaving the present system of market arrangements and other incentives unchanged is not an option.

If the result of these two statements is that nuclear power plants will get large "capacity payments" whether or not they operate and the wholesale market is abandoned in favor of a much more planned (less economically risky) system, the income for a nuclear power plant operator could be sufficiently guaranteed (by consumers) so that the economic risks of nuclear power could be reduced sufficiently so as to allow for cheap financing.

7. Germany

Germany operates 17 power reactors. In 2002 the parliament passed a nuclear phase-out law that requires they be shut down after an average lifetime of about 32 years. However, the utilities had a total "nuclear electricity-generating budget" of 2,623 billion kWh (corresponding to the annual world nuclear power production) and can transfer remaining kWh from one reactor to another unit. Two units have already been shut down under the phase-out law (Stade, Obrigheim). A third unit (Mülheim-Kärlich) that had been under long-term shutdown since 1988 has been closed for good. The construction of new nuclear plants and spent-fuel reprocessing (beyond quantities of fuel shipped to reprocessing plants until June 30, 2005) is prohibited.

Some expected the election of the new Merkel government in September 2009 to lead to a reversal of the phase-out policy and perhaps even new orders. However, the new coalition government led by the Christian Democrats (CDU) with the Free Democrats (FDP) and the Christian Social Union (CSU) has been cautious in changing the law. The government has signaled it might extend the life of the existing plants but it has agreed not to remove the phase-out policy.[57] For fall 2010, the government has promised a national review of energy policy that will take a comprehensive look at

56 Ofgem, "Action Needed To Ensure Britain's Energy Supplies Remain Secure," press release R5, February 2010, http://www.ofgem.gov.uk/Media/PressRel/Documents1/Ofgem%20-%20Discovery%20phase%20II%20Draft%20v15.pdf.

57 *Nucleonics Week*, "New German Government Will Postpone Nuclear Policy Decisions until Late 2010," November 5, 2009.

the situation and propose the government's strategy, including the issue of reversing the phase-out policy.

While it is clear that the two major utilities, RWE and E.ON, would like to build new nuclear plants, their first priority will be to maintain their existing plants in operation. Two, Neckarwestheim 1 and Biblis A, will be closed in 2010 unless the government acts. If the life of the existing plants is extended, their initial capital costs will have been repaid and – provided major repairs and upgrades are not needed – these plants will produce very cheap power. One German economist, Wolfgang Pfaffenberger, estimated that these additional profits could amount to €200 billion, if the life of the existing 17 reactors was extended to 60 years.[58] Until now the government has struggled to answer how it can legally justify the "use" of these windfall profits if it allows operators to keep their plants running longer.

8. Other markets

While many countries have expressed an interest in new nuclear power plants, the time from "expression of interest" to the actual order is a very long one and one in which there is ample scope for failure. In this section, we therefore concentrate on markets that are key, especially Germany and Italy; ones where calls for tender have already taken place, for example, South Africa and Canada; and countries where efforts to restart work on partially built plants are underway.

8.1. United Arab Emirates

In December 2009, the UAE ordered four nuclear reactors from Korea using AP1400 technology, beating opposition from consortia led by EDF (including GDF Suez, Areva, Total with the EPR) and GE-Hitachi (technology unspecified).[59] The contract is with Korean Electric to build and operate the plants, the first coming on-line at an unspecified site in 2017 and the last by 2020. KEPCO will provide design, construction, and maintenance for the nuclear reactor and will subcontract some of the work to equipment suppliers such as Hyundai, Doosan, and Samsung. The terms of the deal and what is included are not clear, although the contract is reported to be worth $20.4 billion. The Korean bid was reported to be $16 billion lower than the French bid, and the GE-Hitachi bid was reported to be significantly higher.[60] It appears not to be a whole project "turnkey" (fixed price) deal. Korean companies will hold an equity stake in a joint venture with UAE public

58 *Nucleonics Week*, "Tax Revenue from Longer Lifetimes No Incentive for New German Regime," December 4, 2009.

59 *Korea Herald*, "Korea Wins Landmark Nuclear Deal," December 28, 2009.

60 *Right Vision News*, "UAE: Middle East Leads Rally in Nuclear Plant Orders," January 12, 2010.

companies, which will operate the plants after their completion.[61] It is not clear how the plants will be financed.

There seems to be ample scope for things to go wrong with this project:

- The technology is untested: there is only about a year of construction experience with this design;
- There is little nuclear expertise in the region;
- The timescale will be very difficult to meet and the contract price appears to be about 40 percent lower than the cost estimates for plants planned by experienced US utilities;
- The Korean nuclear industry has no experience with supplying reactors outside Korea;
- There is little of the infrastructure needed to operate a nuclear power plant in the UAE – for example a safety regulator was only set up in late 2008.

8.2. South Africa

As discussed in Section 2.4, South Africa was pinning its hopes for its nuclear program on the Pebble Bed Modular Reactor (PBMR) from 1998 onwards. However, by 2006 it was clear that the PBMR would at best be long-delayed, and at worst not viable. The PBMR is now unlikely to be deployed even as a demonstration plant before 2020 and the South African state-owned utility, Eskom, is not expecting to order any units of this design.

The South African government and Eskom then began to talk about a program of what they termed conventional nuclear power plants. As with the PBMR, their estimates for duration and costs were hopelessly unrealistic. In 2006,[62] the South African government forecast that a new unit could be on-line between 2010 and 2012.

By mid-2007, Eskom was targeting construction of 20,000 MW on new nuclear capacity by 2025, although completion of the first unit had slipped to 2014.[63] It expected a construction cost of $2,500/kW. In January 2008, Eskom received two bids in reply to its call for tenders from November of the previous year for 3200 to 3400 MW of new nuclear capacity in the near term and up to 20,000 MW by 2025. One bid was from Areva for two EPRs (plus 10 more for the long-term) and the other from Westinghouse for the three AP1000s (plus 17 more in the long term).[64] Both

61 *International Oil Daily*, “South Korean Consortium Awarded UAE Nuclear Contract,” December 29, 2009.
62 *Sunday Times* (South Africa), “SA Going Nuclear,” June 24, 2006.
63 *Nucleonics Week*, “Cabinet Mulls Policy as Eskom Launches Consultation on New Plant,” June 7, 2007.
64 *Nucleonics Week*, “Eskom Gets Bids for Two EPRS, Three AP1000s, Bigger ‘Fleet,’” February 7, 2008.

claimed their bids were "turnkey," but whether they were really turnkey in the fixed price sense or whether they were simply for the whole plant is not clear.

It was later reported that the bids were for around $6,000/kW – more than double the expected price.[65] It was therefore no surprise when Eskom abandoned the tender in December 2008 on the grounds that the magnitude of the investment was too much for it to handle.[66] While Eskom is still claiming it expects to order nuclear plants, it seems unlikely that it will be able to finance these plants.

Finally in November 2008, Eskom admitted defeat and scrapped its tender because the scale of investment was too high. This was despite the willingness of Coface, the French government's loan guarantee body, to offer export credit guarantees and despite Areva's claims that it could have arranged 85 percent of the financing.[67] In February 2009, Eskom also abandoned plans to build PBMRs.[68]

Engineering News reported that the issue was the credit rating of Eskom[69]:

> In fact, ratings agency Standard & Poor's said on Thursday that South Africa's National Treasury needed to extend "unconditional, timely guarantees" across all Eskom's debt stock if it hoped to sustain the utility's current BBB+ investment-grade credit rating. The National Treasury was still to announce the details of the package. The Eskom board had, as a result, decided to terminate the commercial procurement process to select the preferred bidder for the construction of the Nuclear-1 project.

This history illustrates that loan guarantees are not enough in themselves to guarantee nuclear projects can be funded. If the credit rating of the utility is at risk, it will be hard to proceed.

8.3. Canada

In 2007, Ontario Power Authority (OPA), the public body responsible for planning the Ontario power system, had assumed nuclear power plants could be built for about C$2,900/kW.[70] On June 16, 2008, the Canadian government announced Darlington in Ontario as the site for a two-unit new build project and on May 20, 2009, information leaked that the Ontario government had chosen AECL as the leading bidder over Areva and Westinghouse to start building the first new nuclear

65 *Nucleonics Week*, "Big Cost Hikes Make Vendors Wary of Releasing Reactor Cost Estimates," September 11, 2008.

66 *Nucleonics Week*, "Eskom Cancels Tender for Initial Reactors," December 11, 2008.

67 *The Star*, "Nuclear Bid Had Funding – AREVA," January 30, 2009.

68 PBMR pty, "PBMR Considering Change in Product Strategy," news release, February 5, 2009, http://www.pbmr.co.za/index.asp?Content=218&Article=104&Year=2009.

69 *Engineering News*, "Eskom Terminates Nuclear 1 Procurement Process, but SA Still Committed to Nuclear," December 5, 2008.

70 *Toronto Star*, "Nuclear Bid Rejected for 26 Billion: Ontario Ditched Plan for New Reactors over High Price Tag That Would Wipe Out 20-Year Budget," July 14, 2009.

plants in Canada in 25 years. Two new reactors were projected to start operating by 2018. However, the provincial government reportedly conditioned any go-ahead on financial guarantees by the federal government to cover the financial risks involved.[71] Three bids were received, one from Areva and one from AECL, although only the AECL bid complied with the requirement that the vendor assume the construction risk. Ontario Energy and Infrastructure Minister George Smitherman said that only the AECL bid complied with the province's requirement for vendors to bear the entire risk of cost-overruns.[72]

There was a press report on the size of the bids.[73] This suggested that Areva's non-compliant bid was C$23.6 billion (US$21 billion) for two EPRs (1600 MW each) or C$7,375/kW (US$6,600/kW), while AECL's compliant bid was C$26 billion (US$23 billion) for two ACR-1000s (1200 MW each) or C$10,800/kW (US$9,600/kW). The compliant bid was nearly four times the amount projected by the OPA only two years previously. The Westinghouse bid was reported to be about midway between the other two bids. Not surprisingly, Ontario decided to suspend the tender.

Subsequently, Areva disputed the published bid price, but they were not willing to supply the actual price they bid. There was also reported to be a number of additional items included over and above those included in the "overnight price," including: the construction of the transmission and distribution infrastructure to deliver the power from the Darlington site to customers in the northeastern United States; and the price of nuclear fuel for 60 years and decommissioning costs.[74]

The failure of AECL to be awarded this tender put its future as a reactor vendor in doubt and AECL was put up for sale at the end of 2009.[75]

8.4. Turkey

Turkey has been holding calls for tender for nuclear power plants for about 30 years but has yet to place an order. In 2008, Turkey opened a call for tenders for 3000 to 5000 MW of new nuclear capacity. Bidders would be required to cover not just the construction cost but would be required to operate the plant for 15 years, offering the power at a fixed price.[76] This was an extraordinary level of risk to ask the vendors to cover. Despite reported interest from vendors such as GE-Hitachi,

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71 *The Globe and Mail*, "AECL Favoured to Build Ontario Reactors: Sources," May 20, 2009.
72 *Nucleonics Week*, "Areva Disputes EPR Cost Figure as Canadians Grapple with Risk Issue," July 23, 2009.
73 *Toronto Star*, "Nuclear Bid Rejected."
74 *Nucleonics Week*, "Areva Disputes EPR Cost."
75 *The Globe and Mail*, "Canada Puts Its Nuclear Pride on the Block": "Under weight of record deficit, Tories seek bids on AECL's reactor wing. The Candus are a point of pride in Canada's engineering history and the sale is sparking fears the technology will leave the country," December 18, 2009.
76 *Nucleonics Week*, "GE-Hitachi Plans Bid To Build ABWR in Turkey; Other Vendors Cautious," September 11, 2008.

Toshiba/Westinghouse, Korea, and Areva, in January 2009 when bidding closed (it had to be extended), the only bid came from the Russian supplier, Atom Stroy Export (ASE). The price bid was reported to be $211.6/MWh.[77] Subsequently, a revised bid of $151.6/MWh was presented after TETAS, the state-owned electricity trader, submitted its report on the tender to the government stating the bid was too high to proceed with.[78] In November 2009, the Turkish government scrapped the tender, which was, by then, under threat of being invalidated by a court decision following action by the Turkish Chamber of Engineers.[79]

8.5. Italy

In 1987, a referendum led to the closure of the four operating nuclear power plants in Italy and the abandonment of work on construction of another nuclear station. The Berlusconi government has introduced legislation that would pave the way for the reintroduction of nuclear power in Italy. Four 1650 MW EPRs could be built, with construction starting as early as 2013, under an agreement signed in February 2009 by the French utility, EDF, and the largest Italian utility, ENEL.

ENEL has not selected the sites for these units yet. It has said the cost would be about €4 to 4.5 billion ($5.9 to 6.6) each or $3,600 to 4,000/kW.[80] There has been speculation about other competing bids to build nuclear power plants – for example, a consortium led by A2A, the Milan-based utility offering AP1000s – but these projects are much less advanced than those of ENEL.[81]

8.6. Brazil

Brazil operates two nuclear reactors, the first of which, Angra-1, was ordered in 1970 from Westinghouse. The reactor went critical in 1981. In 1975, Brazil signed with Germany what remains probably the largest single contract in the history of the nuclear industry for the construction of eight 1300 MW reactors over a 15-year period. The outcome was a disaster. Due to an ever-increasing debt burden and obvious interest in nuclear weapons by the Brazilian military, practically the entire program was abandoned. Only the first reactor covered by the program, Angra-2, was finally connected to the grid in July 2000 – 24 years after construction started. The construction of Angra-3 was halted in June 1991. Attempts by the publicly owned company, Eletronuclear, to get construction restarted have been continually delayed. Work was reported to have restarted in October 2009 with expected completion in 2015.[82] In January 2010, Areva NP

77 *Prime-Tass English-language Business Newswire*, "DJ Atomstroyexport Grp Revises Bid in Turkish Nuclear Tender – IHA," January 19, 2009.

78 *Turkey Today*, "State-run TETAS Presents Report on Nuclear Power Tender to Energy Ministry," June 30, 2009.

79 *Agence France Presse*, "Turkey Scraps Nuclear Power Plant Tender," November 20, 2009.

80 *Nucleonics Week*, "Enel Targets 2020 for Operation of First Italian EPR Unit," October 8, 2009.

81 *Nucleonics Week*, "Milan Utility A2A Could Become Hub of AP1000 Consortium for Italy," October 22, 2009.

82 *Esmerk Brazil News*, "Brazil: Angra 3 Works Start," October 13, 2009.

applied to the German government for loan guarantees worth €1.4 billion from the German credit guarantee agency, Hermes, to complete Angra-3.[83]

Beyond this, the Brazilian government was expecting, in late 2009, to announce the sites for four new reactors. The Energy Minister, Edison Lobao, has said each of the units is expected to cost about $3 billion and generate up to 1500 MW. This projected cost of $2,000/kW appears hopelessly unrealistic and there must be strong doubts about whether Brazil will proceed with nuclear orders in the next five years.

8.7. Eastern Europe

In this section we focus on efforts to restart work on partially built plants, especially those in Bulgaria, Romania, and the Slovak Republic. New reactors are being considered for the Baltic States, Poland, and the Czech Republic, but these were all some way from placing an order. In Bulgaria, Romania, and the Slovak Republic, the projects to complete partially built units have been delayed by up to a decade and their completion is still far from certain.

8.7.1. Slovak Republic

Mochovce was planned to host four Soviet-designed reactors of the WWER-440 design. Work on this site was stopped in 1990 but work on two units was later restarted and these were completed in 1998 and 1999. In October 2004 the Italian utility ENEL acquired 66 percent of Slovenske Elektrarne (SE). As part of its bid, ENEL proposed to invest nearly €2 billion in new generating capacity, including the completion of the third and fourth units of Mochovce. In February 2007, SE announced that it was proceeding with the completion of these units and that ENEL had agreed to invest €1.8 billion. Although the European Commission gave its permission for construction to restart in July 2008, it noted that the reactor did not have a "full containment" structure, which is used in the most recent construction of nuclear power plants planned or under way in Europe, and they requested that the investor and national authorities implement additional features to withstand impact from small aircraft. Despite pressure from the Slovak government, it took until June 2009 to reactivate construction. The two units are now scheduled for completion in 2012 and 2013 respectively.

8.7.2. Romania

The Cernavoda nuclear power plant was expected to house five "Candu" units when a contract was placed to build them in 1980. Construction started in 1980 but later, all efforts went to complete unit 1, which went on-line in 1996. A second unit was completed in 2007 and plans are being developed to complete two additional units. Bids have been solicited to create an independent

83 *Taz, di tagezeitung*, "Siemens will Staatshilfe für Atom-Export," January 7, 2010.

power producer between the utility, SNN, which will complete and provide operation and maintenance, and a private investor. Financing has proved difficult and delays have continued. Initially, commissioning of unit 3 was due in October 2014 and unit 4 in mid-2015. However, this has now been revised and the first unit is not expected to be completed until 2016 at the earliest.[84]

8.7.3. Bulgaria

In 2003 the government announced its intention to restart construction at the Belene site in northern Bulgaria. Construction of a reactor began in 1985, but following the political changes in 1989 construction was suspended and formally stopped in 1992. In 2004 a call for tenders for the completion of the 2000 MW of nuclear capacity was made. In October 2006 a consortium led by the Russian company, Atom Stroy Export (ASE) was awarded the €4 billion contract.

A Belene construction consortium has been established in which the state utility, NEK, will retain overall control, with 51 percent, with the remaining shares having been put to tender. In late 2008 German utility RWE was announced as the strategic investor with a requirement to put up €1.275 billion as well as provide a €300 million loan in advance. This led to the formation of the Belene Power Company in December 2008 as a joint venture. However, RWE subsequently withdrew and at the end of 2009, financing was still being arranged.[85]

8.7.4. Other countries

In 2009, the Czech state-controlled utility, CEZ, opened a call for tenders for two new reactors to be built at the Temelin site, where two reactors already operate with an option to build a third unit at another existing site, Dukovany.[86] The bidders are reported to be Westinghouse, Atom Stroy Export, and Areva although the final decision is not expected before early 2012 with completion of the three units expected in 2019, 2020, and 2023–25.

The Polish government has expressed its intent to build new nuclear power plants but the plans are at an early stage. The Lithuanian government would like to replace the two Soviet-designed nuclear reactors it has retired recently but lacks the financing to do so. Unless a vendor is prepared to organize a deal under which a partner of the vendor would own and operate the plant (as Korea has done in the UAE), it seems unlikely a reactor order will be possible.

84 *Nucleonics Week*, "Economic Crisis Ends Romania's Plan for Majority Stake in Cernavoda-3, -4," September 3, 2009.

85 *Balkans Business Digest*, "Moscow in Talks with Sofia Over Stake in Belene Nuke," December 28, 2009.

86 *Czech Republic Today*, "CEZ Admits All Bidders for Temelin Construction to Second Stage," February 22, 2010.

9. Review of utility construction cost-estimates

Many of the recent utility cost-estimates have come from the United States. These cost estimates may be more reliable than other utility cost-estimates as the utilities will need to provide reliable cost estimates to obtain loan guarantees and may also need to account to state energy regulators for the costs they expect to incur. However, there have been indications of the results of three calls for tenders and the experience from Olkiluoto and Flamanville to add.

9.1. United States

Table 10. Construction costs for US nuclear power plants

Plant	Technology	Cost estimate (US$bn)	Cost estimate US$/kW
Bellefonte 3, 4	AP1000	5.6–10.4*	2,500–4,600
Lee 1, 2	AP1000	11*	4,900
Vogtle 3, 4	AP1000	9.9	4,190
Summer 2, 3	AP1000	11.5	4,900
Levy 1, 2	AP1000	14	5,900
Turkey Point 6, 7	AP1000	15–18	3,100–4,500
South Texas 3, 4	ABWR	17	6,500
Grand Gulf	ESBWR	10+	6,600+
River Bend	ESBWR	10+	6,600+
Bell Bend	EPR	13–15	8,100–10,000
Fermi	ESBWR	10	6,600+

Source: Various press reports

Estimates marked * are overnight costs; other estimates include interest.

Table 10 shows the most recent construction costs for US nuclear power plants. A number of factors emerge from this table. First, most of the estimates, especially the most fully worked out, are for the AP1000 design. Because this and the ABWR are the only designs that have completed their NRC review process – albeit that both designs are being revised again – it is easier to make construction cost-estimates because the design is closer to a final design. However, it is difficult to draw very strong conclusions from this table, other than that cost estimates appear to be at least four times the $1,000/kW figures that were being claimed by the nuclear industry in the late 1990s and that cost estimates were continuing to rise at the end of 2009. The basis for the figures varies: Some include financing, some include transmission costs, so direct comparisons are not reliable.

9.2. Other countries

Table 11 summarizes recent cost-evidence from countries that have got at least as far as completing a call for tenders (see Section 6 for further details).

Table 11. Recent nuclear power plant bids (US$/kW)

Country	Pre-bid forecast	Lowest bid/contract price	Most recent estimate	Status
South Africa	2,500	6,000	-	Tender abandoned
Canada	2,600	6,600	-	Tender abandoned
UAE	-	3,700	-	Awaiting construction start
France	-	2,700	3,300	Construction from 12/2008
Finland		2,500	4,500	Construction from 7/2005

Source: Author's research

9.3. Summary

It is clear that in the past decade, the estimated construction cost for new nuclear plants has increased several-fold, perhaps more than five-fold, with no sign that the rate of increase is leveling out. All past experiences suggest that when actual construction costs are established, they will be substantially more than these estimates. However, what is more difficult to establish is whether current estimated costs really are significantly higher than past costs and, if they are, why estimated costs have increased at such a rate.

The Sizewell B plant, the most recent plant built in the United Kingdom, which did not encounter major problems in the construction phase, cost in the range of £3 billion, not out of line with current cost estimates, while US plants completed in the 1990s also cost about the same. It may be that plant designers assumed that starting without all the "baggage" that earlier generations of designs had acquired in response to the safety challenges thrown up by Three Mile Island and Chernobyl, new designs could meet the safety requirements but with much simpler designs, which would be cheaper and more efficient. It may be that this perception was an illusion and the designs have become no less complicated. The need to provide protection against aircraft strikes also seems to have proved more onerous than the nuclear industry anticipated.

The figure of $1,000/kW may also not have emerged "bottom-up" from design studies but from "top-down" considerations that this was the cost needed to make nuclear competitive. In short, the

$1,000/kW was an imposed target with no technical basis. To the extent there has been cost escalation, a variety of explanations can be suggested for this.[87] These include:

- rapidly rising commodity prices driven by China's demands for them, which makes all power plants more expensive, but affects nuclear plants particularly severely because of their physical size;
- lack of production facilities, which means that utilities hoping to build nuclear plants are taking options on components like pressure vessels;
- shortages of the necessary nuclear skills as the nuclear workforce ages and is not replaced by younger specialists;
- weakness of the US dollar; and
- greater conservatism in cost estimation by utilities

All of these appear plausible at first sight, but closer examination suggests not all are convincing.

- **Commodity prices.** In the past decade, commodity prices of many metals and other raw materials have increased significantly – the so-called China effect. However, commodity prices have fallen sharply following the financial crisis with no corresponding fall in estimated construction costs.
- **Component bottlenecks and skills shortages.** Standard & Poor's[88] places emphasis on the issue of shortage of component manufacturing facilities. It identifies pressure vessels, circulating water pumps, and turbine forgings as particularly problematic. There is only one supplier, Japan Steel Works, which manufactures ultra-heavy forgings for pressure vessels. While a large demand for these products would undoubtedly lead to an increase in capacity, the certification requirements for nuclear components will make this a slow process and companies will be reluctant to commit the investment needed to build such production facilities until they see solid evidence of long-term demand. Standard & Poor's also notes skills shortages as a major constraint and, again, such skills shortages cannot quickly or easily be overcome. It expects the United States to have to rely on expertise from foreign countries, especially France and Japan initially.
- **Currency instability.** Currency values have been particularly volatile in the past two years, with the dollar hitting historic lows against European currencies. From November 2005 to

87 For more discussion on these factors, see Standard & Poor's, "Construction Costs To Soar for New U.S. Nuclear Power Plants" (2008).

88 Ibid.

July 2008, the value of the dollar against the euro fell from €1=$1.17 to €1=$1.57. Yet by November 2008, the dollar had recovered much of this ground to €1=$1.27. It seems likely that at least some of the cost escalation was related to the decline of the US dollar, making some inputs more expensive in dollar terms but not necessarily in euro terms.

- **Utility conservatism.** Greater awareness among utilities regarding the accuracy of their estimates and whether there will be serious financial consequences is difficult to quantify. Experience with Olkiluoto and the awareness that regulators and the public are likely to be much less indulgent to cost-overruns than they were in the past will be a strong incentive for utilities to build-in ample contingencies.

10. Need for and extent of public subsidies

Successive studies by the British government in 1989, 1995, and 2002 came to the conclusion that in a liberalized electricity market, electric utilities would not build nuclear power plants without government subsidies and government guarantees that cap costs. In most countries where the monopoly status of the generating companies has been removed, similar considerations would apply. The recent order in Finland clearly does not follow this expectation, but, as argued above, the special status of the buyer as a not-for-profit company owned by the industrial companies contracted to buy the output of the plant means that the special conditions in Finland provide an example that other countries are not likely to follow. The experience with this project has been consistently very bad and this is likely to be a further deterrent to utilities operating in competitive electricity markets from building nuclear power plants unless they are very fully insulated from market risks.

The US program to revive nuclear ordering has demonstrated that the key requirement for ordering is either government-backed loan guarantees or a regulatory commitment to allow the utility to recover its costs from consumers. These conditions allow utilities to borrow the money they need very cheaply.

The areas where subsidies and guarantees might also be required would be particularly those that are not fully under the control of the owner. These include:

- Construction costs. The construction costs of a new nuclear power plant would be high and there would be a significant risk of cost-overruns. The government might therefore have to place a cap on the costs a private investor would have to pay.

- Operating performance. There would be a significant risk that performance would be poorer than forecast. Reliability is largely under the control of the owner and it is not clear whether developers would be sufficiently confident in their abilities to take the risk of poorer-than-expected reliability.
- Non-fuel operations and maintenance costs. Similarly, this is largely under the control of the owner and they may be willing to bear this risk.
- Nuclear fuel cost. Purchasing fuel has not generally been seen as a risky activity. Uranium can easily be stockpiled and the risk of increasing the fuel-purchase cost can be dealt with. The cost of spent-fuel disposal (assuming reprocessing is not chosen) is, however, much more contentious, and nuclear owners might press for some form of cap on disposal cost, similar to the US arrangements.
- Decommissioning costs. The costs of decommissioning are very hard to forecast, but the costs will arise far into the future. Contributions to a well-designed, segregated decommissioning fund appear relatively manageable, although if experience with decommissioning and waste disposal reveals that current estimates are significantly low, or if returns on investment of the fund are lower than expected, contributions might have to be increased significantly. Private developers might therefore seek some “cap” on their contributions.

Guarantees would be particularly extensive and high for the first units built, which would bear the setup costs for a new technology. If a series of plants are built and experience with them is good, it is possible that the market would be willing to bear more of the risk, although a political commitment to promote nuclear power is by no means sufficient to ensure the completion of a program. It should be remembered that the Reagan and Thatcher administrations, which promised a strong revival in the nuclear industry, presided over steep declines in the fortunes of nuclear power.

11. Conclusions

In the decade since the Nuclear Renaissance based on Generation III+ designs was first mooted in the late 1990s, the forecast economics of new nuclear plants has deteriorated dramatically. Paradoxically, this seems to have made many governments, including those of the United states, the United Kingdom, and Italy, far more determined to force new nuclear power plant orders through. Indeed, the efforts to relaunch nuclear ordering have been associated in a very personal way with the leaders of these countries: Bush, Blair, and Berlusconi.

While such powerful political backing can be a strong facilitating force, for example short-cutting planning procedures and making public subsidies available, it can also be a weakness. When governments change, the new government may be less enthusiastic.

Some of the enthusiasm for nuclear power appears to be based on the blatantly misguided view that expanding nuclear power can be a major way to cut emissions of greenhouse gases. Electricity typically makes up only about 20 percent of final energy demand, and even if this proportion was increased somewhat and the proportion of electricity demand generated by nuclear power was also increased, it would still be hard to get the proportion of energy met by nuclear power much above 10 percent. Increasing world nuclear capacity four- or five-fold would raise major issues – for example of uranium resource adequacy, availability of acceptable sites, and waste disposal – even if the materials, skills, and financial resources could be assembled.

Worldwide, the ordering rate for new nuclear power plants has been at a low ebb for 30 years. In the past few years, orders for China and, to a lesser extent, Korea and Russia, have substantially increased the number of plants under construction – in January 2010, there were 20 plants under construction in China alone. But these orders are generally being supplied by national vendors and are generally for earlier generation designs. The markets that must be reopened if the Renaissance is to happen, such as the United States, the United Kingdom, and Italy, are still several years away from ordering, and the Generation III+ designs are also several years from being demonstrated in operation.

While powerful political backing can push the Nuclear Renaissance so far, if the fundamentals of technology and economics are not right, political backing – as was provided by Thatcher and Reagan in the 1980s – will ultimately not be enough. This report focuses on the economics, but there is an overlap between economics and technology. In principle, almost any design can be made to meet the safety standards required by the regulatory authorities, but the cost of doing so could be prohibitive.

It has proved much more difficult to obtain regulatory approval for the new designs than was expected. The US Nuclear Power 2010 program was launched with an objective to get a Generation III+ design on-line in the United States by 2010. It seems that only one design (AP1000) will have completed its design certification by then and even this design is now being reviewed again following submission of revisions to it. By the start of 2010, it was clear that none of the designs will be fully certified before 2011 and perhaps later. Significant design issues – such with the

Control and Instrumentation system for the EPR[89] and the Shield Building for the AP1000[90] – can likely be resolved, but in doing so, costs could be added and delays will occur.

There are three reasons why forecasting the cost of power from a nuclear plant is difficult and controversial:

- Several of the variables relate to processes that have not been proven on a commercial scale, such as decommissioning and waste disposal, especially for intermediate- and high-level waste. Experience of nuclear power suggests that unproven processes could easily cost significantly more than expected. There is therefore a strong risk that forecasts of these costs could be significantly low.
- For some of the variables, there is no "correct" answer. For example, the discount rate could vary widely and there is no consensus on how provisions to pay for decommissioning should be set.
- There is a lack of reliable, up-to-date data on actual nuclear plants. Utilities are secretive about the costs they incur, while in the past two decades, there have been only a handful of orders in Western Europe and none since 1980 in North America. All modern designs are therefore untested.

Over the past four decades, there has consistently been a wide gap between the performance of existing nuclear plants and the performance forecast for new nuclear plants. These expectations have almost invariably proved overoptimistic. The gap in expected performance is as wide as ever between current forecasts of the economic performance of the next generation of nuclear power plants and that of the existing plants. The fact that in the past such expectations have proved wrong is not a guarantee that current forecasts would prove inaccurate. It does suggest that forecasts that rely on major improvements in performance should be treated with some skepticism. The most important assumptions are:

- construction cost
- operating performance
- non-fuel operations and maintenance cost
- nuclear fuel cost

89 See for example, *Health & Safety Executive*, "Joint Regulatory Position Statement on the EPR Pressurized Water Reactor," Release No: V4 22/10/2009, November 2, 2009, http://www.hse.gov.uk/PRESS/2009/hse221009.htm.

90 See for example, Nuclear Regulatory Commission, *NRC Informs Westinghouse of Safety Issues with AP1000 Shield Building*, http://www.nrc.gov/reading-rm/doc-collections/news/2009/09-173.html.

- decommissioning cost

Nuclear power plants can only be built where extensive government guarantees and subsidies are provided.

There might also need to be commercial guarantees that the output of the plants would be purchased at a guaranteed price. It seems doubtful that such an extensive package of “state aids” would be acceptable under EU competition law.

There is a significant mismatch between the commercial interests of the companies involved and the interests of society in general. Costs incurred far in the future – no matter how large or uncertain – have little weight in commercial cost appraisals, and companies are also absolved of the risk of nuclear accidents by international treaties. So cost appraisals made from a corporate point of view must be corrected so that they reflect fully the broader societal perspective.

As with the many previous predictions of a “second-comings” for nuclear power since 1980, the result of the current “Renaissance” will not be a large number of new nuclear orders. Countries where nuclear orders have not been problematic will continue to order plants. Even in these countries, enthusiasm will dim as the escalating costs become apparent, the problems of waste disposal remain unaddressed, and nuclear capabilities die away.

In the “Renaissance countries,” a handful of plants will be built, proving only that nuclear power plants can be built if governments are prepared to provide large enough subsidies and to override proper democratic consultation processes. The real loss however will be – as it has been over the past few decades – the opportunity cost of not pursuing more cost-effective options of meeting the energy policy goals of providing affordable, reliable, and clean energy – or efficiency savings. The cost-curve for nuclear power has always been upwards. In other words, instead of getting cheaper over time due to the learning, scale economies, and technical progress effects, as most technologies do, nuclear costs have increased. Analyses by Froggatt and Schneider (2010) show that energy efficiency and renewables are far more cost-effective than nuclear power and that their cost curve is downwards.[91] If some of the resources being poured into another fruitless attempt to revive nuclear power were devoted to these sources, the economic gap between energy efficiency and renewables and nuclear would be highly likely to grow even wider.

91 A. Froggatt (with M. Schneider), “Systems for Change: Nuclear Power vs. Energy Efficiency and Renewables?” Paper prepared for Heinrich Böll Foundation, April 2010.

Appendix 1 Reactor technologies, current designs, and vendors

Reactor technologies

Nuclear power reactors can be broadly categorized by the coolants and moderators they use. The coolant is the fluid (gas or liquid) that is used to take the heat from the reactor core to the turbine generator. The moderator is a medium that reduces the velocity of the neutrons so that they are retained in the core long enough for the nuclear chain reaction to be sustained. There are many possible combinations of coolant and moderator, but among the reactors currently in service or on offer, there are four possible coolants and three moderators.

The most common type of nuclear plant is the light-water reactor (LWR), for which there are two variants, the pressurized water reactor (PWR), and boiling water reactor (BWR). These are derived from submarine propulsion units and use ordinary water ("light water") as coolant and moderator. The advantage of water is its cheapness, although it is not the most efficient moderator (water molecules absorb some of the neutrons rather than them "bouncing" off the water). As a result, the proportion of the active isotope of uranium has to be increased from about 0.7 percent, the amount found in natural uranium, to more than 3 percent. This process is expensive.

As a coolant, the disadvantage of water is that it is designed to work as a liquid. If there is a break in the coolant circuit, the water will boil and will cease to be as effective as assumed. Avoiding the possibility of "loss of coolant accidents" is therefore a major priority in reactor design. The main difference between a PWR and a BWR is that in a BWR, the coolant water is allowed to boil and passes directly to the turbine generator circuit, where the steam generated in the reactor core drives the turbine. In a PWR, the coolant water is maintained as a liquid by keeping it under pressure. A heat exchanger (steam generator) is used to transfer the energy to a secondary circuit where water is allowed to boil and drives the turbine. BWRs are therefore less complex than PWRs, but because the coolant water goes direct to the turbine, radioactive contamination of the plant is more extensive. Most of the Russian-designed plants, WWERs, are essentially PWRs. Britain has one operating PWR, Sizewell B, but no BWRs.

Some plants use "heavy water" as coolant and moderator, the most common of which are the Candu reactors designed in Canada. In heavy water, the deuterium isotope of hydrogen replaces the much more common form of the atom. Heavy water is a more efficient moderator and Candu plants can use natural (unenriched) uranium. However, its greater efficiency is counterbalanced by the cost of producing heavy water. A new Candu design has been proposed that would use light water as a coolant and heavy water as a moderator, but this design is still on the drawing board.

All of the British plants except Sizewell B are cooled by carbon dioxide gas and moderated by graphite. The first-generation plants, the Magnoxes, use natural uranium, but most were unable to operate long-term at their full design rating because the carbon dioxide coolant becomes mildly acidic when in contact with water and causes corrosion of the piping. The second-generation plants use enriched uranium and improved materials were used to prevent corrosion. Graphite is an efficient moderator but is quite expensive compared to water. Its disadvantages are its flammability and its tendency to crack and distort with exposure to radiation. The design used at Chernobyl, the RBMK, also uses graphite as the moderator but uses light water as the coolant.

There has been consistent interest in reactors that use helium gas as the coolant and graphite as the moderator, so-called high temperature gas-cooled reactors (HTGRs). Helium is entirely inert and is an efficient, albeit expensive coolant. The use of helium and graphite means the reactor operates at a much higher temperature than a light-water or carbon-dioxide-cooled reactor. This allows more of the heat energy to be turned into electricity and also opens the way to use some of the heat in industrial processes while still being able to generate power. However, despite research in several countries – including Britain, going back more than 50 years – no commercial design of such a plant has ever been produced and the demonstration plants that have been built have a very poor record.

There has been some discussion of Generation IV designs.[92] While Generation III+ designs are described by the USDOE as "evolutionary," Generation IV designs are described as revolutionary. They are described as "safer, sustainable, economical, more proliferation resistant and secure." The main feature of these designs that would distinguish them from existing designs is that they would use natural uranium much more fully than existing technologies, for example, through use of "breeder cycles," which allow the 99.3 percent of natural uranium that existing reactors do not utilize, to be used. They also operate at higher temperatures than existing reactors and could, for example, be used to produce hydrogen. Six technologies have been identified as being most promising:

- gas-cooled fast reactors
- lead-cooled fast reactors
- molten salt reactors
- sodium-cooled fast reactors

92 For more information on Gen IV technology, see the Generation IV International Forum at http://www.gen-4.org/.

- super-critical water-cooled reactors
- very high-temperature gas-cooled reactors

Only the sodium-cooled fast reactors and the very high-temperature gas-cooled reactors have seen significant development in operating plants. However, both technologies have proved highly problematic. Fast reactors cooled by sodium have been operated since the 1960s and many countries have had sodium-cooled breeder reactor programs, but they have proved very expensive and unreliable, and few countries are now pursuing this technology. As noted above, high-temperature gas-cooled reactors have also been under development in many countries since the 1960s but have also proved impossible to commercialize, and most countries are no longer actively pursuing them.

It remains to be seen whether any of these technologies can be commercialized, but even their proponents acknowledge that they will not be a commercial option before about 2030, so they have no relevance to current reactor choices.

Current designs and vendors

The most relevant designs for orders to be placed in the next decade in the West are so-called Generation III+. Generation I designs represent the first orders placed in the 1950s and 1960s. Generation II designs represent the majority of units now in service and include plants ordered from the late 1960s to the early 1980s. Generation III plants are those ordered from the early 1980s to around 2000. They incorporate, from the start, the main lessons from the Three Mile Island accident. The main distinction between Generation III plants and Generation III+ plants, which were designed after the Chernobyl disaster, is that the latter incorporate a greater level of "passive" safety as opposed to engineered safety. For example, Generation III+ designs would rely less on engineered systems for emergency cooling and more on natural processes, such as convection. The "9/11" attacks have added another important design consideration and any new design must now be able to demonstrate it can withstand a commercial aircraft being flown into it.

There are a large number of designs that 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 Generation a particular design falls into, but the main features of the Generation III+ design, apart from it being designed in the last 15 years, are:

- a standardized 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.[93]

These characteristics are clearly very imprecise and do not define well what differentiates a Generation III+ plant from earlier designs, other than that the design was evolved from existing models. In the following descriptions, we concentrate on designs that have been ordered, or are being assessed, by safety regulators.

Pressurized Water Reactors (PWR)

There are four main independent vendors of PWR technology from which current designs are derived: Westinghouse, Combustion Engineering, Babcock & Wilcox (B&W), and the Russian vendor, Rosatom.

Westinghouse

Westinghouse technology is the most widely used and has been widely adopted using technology licenses, the main licensees being the French company Areva (up to 2001, known as Framatome), Siemens (Germany), and Mitsubishi (Japan). Westinghouse plants have been sold throughout the world, although it had only one order in the past 25 years (Sizewell B) before it received four orders from China in 2008; its last order in the United States (not subsequently cancelled) was more than 30 years ago. In 1998, BNFL took over the nuclear division of Westinghouse, but in 2006 it was sold to Toshiba. Westinghouse’s main current design is the AP1000, although it has only had orders for four units, all for China.

The AP1000 (Advanced Passive) was developed from the AP-600 design. The rationale for the AP-600 was to increase reliance on passive safety and also that scale economies (from building larger units as opposed to building larger numbers) had been overestimated. An executive of Westinghouse justified the choice of a unit size of 600 MW rather than 1000–1300 MW by stating that “the economies of scale are no longer operative.”[94] The AP-600 went through the US regulatory process and was given safety approval in 1999. By then, it was clear that the design would not be economical and the AP-600 was never offered in tenders. Its size was increased to about 1150 MW in the hope that scale economies would make the design competitive. In September

93 http://www.uic.com.au/nip16.htm.
94 *Nucleonics Week Special Report*, “Outlook on Advanced Reactors,” March 30, 1989, p. 3.

2004, the NRC granted a Final Design Approval, valid for five years, to Westinghouse for the AP1000. The NRC issued a standard Design Certification, valid for 15 years, in 2006. However, Westinghouse subsequently submitted further design changes that will not be approved by the NRC before 2011. The AP1000 is one of the designs being reviewed by the NII under its Generic Design Assessment (GDA) program and the NII expects to complete its assessment by mid-2011, although, as with the EPR, there is no guarantee that it will then be licensed.

Areva

Both Framatome and Siemens became independent of Westinghouse and, in 2000, they merged their nuclear businesses, with 66 percent of the shares going to Framatome and the remainder going to Siemens. Framatome is now controlled by the Areva group, which is more than 90 percent owned by the French government. The Framatome division was renamed Areva NP in 2001. In 2009, Siemens expressed its intention to withdraw from the joint venture, although by the end of 2009, the details of the withdrawal were still being negotiated. Framatome supplied all the PWR plants in France (58 units) and has exported plants to South Africa, Korea, China, and Belgium. Siemens supplied 10 out the 11 PWRs built in Germany and exported PWRs to the Netherlands, Switzerland, and Brazil.

The only Generation III+ PWR design with significant construction experience is the Areva NP European Pressurized water Reactor (EPR). The Finnish government issued a construction license for the Olkiluoto EPR in February 2005 and construction started in summer 2005. Work started on an EPR at the Flamanville site in France in 2007. Two EPRs have also been ordered by China, but by the end of 2009, there was minimal construction experience. The EPR received outline safety approval from the French authorities in September 2004 and from the Finnish authorities in January 2005, although it is now clear, as is discussed later, that many design details remain to be finalized. Areva has asked the NRC, in collaboration with Constellation Energy, under the Nuclear Power 2010 program to begin licensing of the EPR in the United States. Final approval is unlikely to be given before 2012. The EPR is also one of the designs being reviewed by the UK safety authorities, the NII, under its GDA program, which was launched in 2007. The NII expects to complete its assessment by mid-2011, but this does not mean it will necessarily be approved then. For the US market, EPR is an abbreviation for Evolutionary Power Reactor.

The Olkiluoto (Finland) EPR has an output of 1600 MW, although this was increased to 1700 MW for orders after Olkiluoto. The design was developed from the previous Framatome design, N4, with some input from Siemens' previous design, the "Konvoi" plant. A reduction in the refueling time is expected to allow a load factor[95] of about 90 percent.

Mitsubishi

Mitsubishi supplies PWR technology to Japan, where it has built 22 units, but it has never tried to sell plants to the international market before it submitted it to the US Nuclear Power 2010 process. One US utility is planning to build an Advanced PWR (APWR), its most modern design. Development of the APWR by Mitsubishi and its technology licensor, Westinghouse, was launched around 1980, but first orders have continually been delayed. Orders for a unit for the Tsuruga (Japan) site have been expected within about a year for a decade, but as of the end of 2009, the order had still not been placed. A more advanced version of the APWR is being reviewed by the NRC and one US utility, TXU, plans to order it. The NII does not expect to complete its review before about 2012.

Combustion Engineering

Combustion Engineering produced its own design of PWR, which is installed in the United States. Outside the United States, its technology was licensed by Korea. The nuclear division of Combustion Engineering was taken over by ABB in 1996 and, in turn, taken over by BNFL in 1999. It is now part of the Westinghouse division and was sold in 2006 as part of the Westinghouse division to Toshiba.

Combustion Engineering's System 80+ design received regulatory approval in the United States in 1997. System 80+ is not being offered for sale by Westinghouse. However, the Korean vendor, Doosan, has used this design under license from Westinghouse to develop its APR-1400, which was ordered for Korea in 2008. Korea did offer the design for the Generation III plant tender held in 2005 for China but it was rejected. In December 2009, it won a tender for four units for installation in the United Arab Emirates and the suppliers are now expected to offer it to Turkey.

Babcock & Wilcox

Babcock & Wilcox (B&W) supplied PWRs of its own design to the US market, but the Three Mile Island accident, which involved B&W technology, effectively ended their interest in reactor sales. The only plant of B&W design built outside the United States was built under license in Germany, but this was closed in 1988 due to licensing problems soon after its completion in 1986 and will not be restarted.

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95 Annual (or lifetime) load factor is calculated as the annual (or lifetime) output of the plant as a percentage of the output the plant would have produced if it had operated continuously at full power and is a good measure of the reliability of the plant.

Rosatom/Atom Stroy Export

Exports of Russian technology are through Atom Stroy Export (ASE), part of the Rosatom company. In 2009, Siemens was negotiating with Rosatom to form a new joint venture to sell Russian technology. The latest Russian design, generating about 1200 MW, is the AES-2006/WWER-1200, offered from 2006 onwards. Two units of this design have been ordered for each of two sites in Russia (Leningrad and Novovoronezh). It won a tender in 2008 for nuclear plants to be built in Turkey, although it was the only bidder and the contract was withdrawn in 2009 because of the high price offered. It may be considered for Finland and India.

Boiling Water Reactors (BWRs)

The main designer of BWRs is the US company General Electric (GE), which has supplied a large number of plants to the USA and international markets such as Germany, Japan, Switzerland, Spain, and Mexico. Its licensees included AEG (subsequently taken over by Siemens), Hitachi, and Toshiba. The Siemens reactor division (now part of Areva NP) offered the SWR design for the Olkiluoto tender, but despite this, the design seems some way from being commercially available.

GE-Hitachi and Toshiba

GE's Japanese licensees continue to offer BWRs in Japan. There are now 32 BWRs in operation or under construction in Japan. A few first-of-a-kind plants in Japan were bought from GE but the rest were split between Hitachi and Toshiba. The Advanced Boiling Water Reactor (ABWR) was developed in Japan jointly by Hitachi and Toshiba and their US technology licensor, GE. The first two orders were placed around 1992 and completed in 1996/97. By the end of 2009, there were four ABWRs in service and one under construction in Japan and two under construction in Taiwan. The ABWR received safety approval in the United States in 1997, but this approval runs out in 2012. It is now being offered by a GE-Hitachi joint venture and by Toshiba, which now operates independently, and both these companies expect to submit an updated design to the NRC to renew its safety approval. It is not known yet how extensive the changes required by the NRC would be and how long recertification would take. Inevitably, the new design will need much more extensive protection against aircraft strikes than the earlier version. The ABWR should probably be classified as a Generation III design, but if it succeeds in having its certification renewed by the NRC, the revised design can probably be described as Generation III+. One utility, NRG, plans to build ABWRs under the US Nuclear Power 2010 program.

The Economic & Simplified BWR (ESBWR) is a 1500 MW design developed by GE. In October 2005, the GE-Hitachi joint venture 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. The ESBWR has been chosen by a number of US utilities under the Nuclear Power 2010 program, although NRC does not expect to complete its review before 2011. The ESBWR was submitted to the UK's GDA review program in 2007, but was withdrawn in 2008. Six US utilities planned to build ESBWRs under the Nuclear Power 2010 program, but one has switched to the ABWR, one appears to have abandoned the project, and there are doubts around the viability of most of the other four projects. There appears to be little interest in the ESBWR outside the United States and the design may have to be abandoned.

Other BWRs

Asea Atom (Sweden) produced its own design of the BWR, nine of which were built in Sweden and two in Finland. Asea Atom merged with Brown Boveri to form ABB, which in turn was taken over by BNFL in 1999 and sold to Toshiba in 2006 as part of the Westinghouse nuclear division. The BWR-90+, a 1500 MW design developed by Westinghouse from the Asea BWR design, has been mooted but development is not advanced.

Candus

The main heavy-water reactor supplier is the Canadian company Atomic Energy of Canada Limited (AECL), which has supplied plants more than 20 units to Canadian utilities as well as exports to Argentina, Romania, Korea, and China. It also sold plants to India but because of proliferation issues, it has had no contact with the Indians since 1975, although India continues to build plants of this 40-year-old design. Argentina has built three heavy-water plants, one Candu and two plants of a German design (one of which is incomplete and no work is currently being carried out on it).

The main future design for AECL will be the Advanced Candu Reactor (ACR), which was expected to be produced in two sizes, 750 MW (ACR-700) and 1100–1200 MW (ACR-1000). Unlike earlier Candus, which used heavy water as a coolant and moderator, these would use light water as a coolant and heavy water as a moderator. The ACR-700 was being reviewed by the 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 United States with Candu technology. The ACR-700 appears to have been subsequently abandoned in favor of the ACR-1000. Any calls for tenders requiring a reactor of this size would probably be offered an updated version of the 30-year-old Candu-6 design. The ACR-1000 was offered in a call for tenders in Ontario but the price offered was far too high. It was also submitted to the UK GDA process in 2007 but was withdrawn soon after. There are now proposals to privatize its state-owned vendor, Atomic Energy of Canada Limited (AECL), and the future of Candu technology for new orders is in doubt.

High-temperature gas-cooled reactors (HTGRs)

It is not clear whether the HTGRs under development should be categorized as Generation III or IV plants. The Pebble Bed Modular Reactor (PBMR) is based on designs developed by Siemens and ABB for Germany, but abandoned after poor experiences with a demonstration plant. It is now being developed 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 PBMR Co., a subsidiary of Eskom, the South African publicly owned electric utility. Funding for its development was contracted to come from Eskom; BNFL; the US utility Exelon; and the South African state-owned Industrial Development Corporation. This investment would entitle the companies to a stake in a new company that would sell the reactors. The project was first publicized in 1998 when it was expected that first commercial orders could be placed in 2003. However, there were greater than anticipated problems in completing the design. Exelon withdrew in 2002 and the other partners paid less than they were contracted to pay, leaving Eskom to bear most of the costs up to 2004 and the South African government directly from then on. The BNFL option has passed to Westinghouse, IDC has withdrawn, and no new investors have been found. The project time-scale has slipped dramatically so that by 2009, first commercial orders were not expected until after 2025. In 2008, a report by the Jülich Research Centre – the German government's nuclear research organization that first developed pebble bed technology – cast doubt on the safety of the design based on a reevaluation of experience with a prototype plant of this design.[96] In March 2009, the South African government announced that it would provide only one more year of funding. PBMR Co. decided to effectively abandon the design they had been developing. They may now develop a much smaller design without some of the advanced features, targeted at the process-heat market such as desalination, coal gasification, and liquefaction. It seems unlikely that the PBMR program will survive long after the end of South African government funding.

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.

96 R. Moormann, "A Safety Re-evaluation of the AVR Pebble Bed Reactor Operation and Its Consequences for Future HTR Concepts," Forschungszentrum Jülich, 2008, http://juwel.fz-juelich.de:8080/dspace/handle/2128/3136.

Appendix 2 Discounting, cost of capital, and required rate of return

A particularly difficult issue with nuclear economics is dealing with, and putting on a common basis for comparison, the streams of income and expenditure at different times in the life of a nuclear power plant. Under UK plans, the time from placing a reactor order to completion of decommissioning could span more than 200 years.

Conventionally, streams of income and expenditure incurred at different times are compared using discounted cash flow (DCF) methods. These are based on the intuitively reasonable proposition that income or expenditure incurred now should be weighted more heavily than income or expenditure earned in the future. For example, a liability that has to be discharged now will cost the full amount, but one that must be discharged in, say, 10 years can be met by investing a smaller sum and allowing the interest earned to make up the additional sum required. In a DCF analysis, all incomes and expenditures through time are brought to a common basis by “discounting.” If an income of $100 is received in one year’s time and the “discount rate” is 5 percent, the “net present value” of that income is $95.23 – a sum of $95.23 would earn $4.77 in one year to make a total of $100. The discount rate is usually seen as the “opportunity cost” of the money, in other words, the rate of return (net of inflation) that would be earned if the sum of money was invested in an alternative use.

While this seems a reasonable process over periods of a decade or so and with relatively low discount rates, over long periods – with high discount rates – the results of discounting can be very powerful and the assumptions that are being made must be thought through. For example, if the discount rate is 15 percent, a cost incurred in 10 years of $100 would have a net present value of only $12.28. A cost incurred in 100 years, even if the discount rate was only 3 percent, would have a net present value of only $5.20. At a discount rate of 15 percent, costs or benefits more than 15 years forward have a negligible value in an normal economic analysis (see Table 12).

Table 12. Impact of discounting: Net present values

Discounting period (years)	3%	15%
5	0.86	0.50
10	0.74	0.25
15	0.64	0.12
20	0.55	0.061
30	0.41	0.015
50	0.23	0.00092
100	0.052	-

150	0.012	-

Source: Author's calculations

If we apply this to nuclear plants operating in a competitive market where the cost of capital will be very high, this means that costs and benefits arising more than, say, 10 years in the future will have little weight in an evaluation of the economics of a nuclear power plant. Thus increasing the life of a plant from 30 years to 60 years will have little benefit, while refurbishment costs incurred after, say, 15 years will equally have little impact.

For decommissioning – for which under UK plans the most expensive stage is not expected to be started until 135 years after plant closure – this means very large decommissioning costs will little impact, even with a very low discount rate that is consistent with investing funds in a very secure place with a low rate of return, such as 3 percent. If we assume a Magnox plant will cost about $1.8 billion to decommission and the final stage accounts for 65 percent of the total (undiscounted) cost ($1,170m), a sum of only $28 million invested when the plant is closed will have grown sufficiently to pay for the final stage of decommissioning.

The implicit assumption with DCF methods is that the rate of return specified will be available for the entire period. Give that even government bonds – usually seen as the most secure form of investment – are only available for 30 years forward, and that a period of 100 years of sustained economic growth is unprecedented in human history, this assumption seems difficult to justify.

So, with nuclear power, there is the apparent paradox that at the investment stage, a very high discount rate (or required rate of return) of 15 percent or more is likely to be applied to determine whether the investment will be profitable, while for decommissioning funds, a very low discount rate is applied to determine how much decommissioning funds can be expected to grow.

The key element resolving this paradox is risk. Nuclear power plant investment has always been risky because of the difficulty of controlling construction costs, the variability of performance, the risk of the impact of external events on the operation, and the fact that many processes are yet to be fully proven (such as disposal of high-level waste and decommissioning). In a competitive environment, there are additional risks because of the rigidity of the cost structure. Most of the costs will be incurred whether or not the plant is operated. Thus, while nuclear plants will do well when the wholesale price is high (as was the case with British Energy from 1996–1999), they will do poorly when the wholesale price is low (2000–2002). The fact that a plant has made good profits for a decade will not protect it from bankruptcy in the bad years, and financiers will therefore see investment in nuclear power as being extremely risky and will apply a very high interest rate that reflects the risk that the money loaned could easily be lost.

Appendix 3 Decommissioning

Decommissioning of nuclear plants has attracted considerable public interest in recent years as reactors get near the end of their lives, forecast decommissioning costs escalate, and weaknesses in the schemes that were meant to provide the funds to do the job become apparent.

Conventionally, decommissioning is split into three separate phases. In phase I, the fuel is removed and the reactor is secured. The time taken to remove the fuel varies, with plants that refuel off-line taking much less time (e.g., PWRs and BWRs). These are designed for about a third of the fuel to be replaced in an annual shutdown of a few weeks. Reactors that refuel on-line (e.g., AGRs and Candus) take much longer because the refueling machine is designed to constantly replace small proportions of the fuel while the reactor is in operation. This requires precision machinery that moves slowly, and removing the entire core may take several years. Once the fuel has been removed, the reactor is no longer at risk of a criticality and the vast majority of the radioactivity and all the high-level waste has been removed. Until this phase has been completed, the plant must essentially be staffed as fully as if it was operating. There is thus a strong economic incentive to complete phase I as quickly as possible, and phase I is invariably completed as quickly as possible consistent with safety. In technological terms, phase I is simple – it represents largely just a continuation of the operations that were being carried out while the plant was operating. Note that dealing with the spent fuel is not included in the cost of phase I.

In the second phase, the uncontaminated or lightly contaminated structures are demolished and removed, leaving essentially the reactor. Again, this is relatively routine work requiring no special expertise. In economic terms, the incentive is to delay it as long as possible to minimize the amount that needs to be collected from consumers to pay for it – the longer the delay, the more interest the decommissioning fund will accumulate. The limiting point is when the integrity of the buildings can no longer be assured and there is a risk they might collapse, leading to a release of radioactive material. In Britain, it is planned to delay stage II until 40 years after plant closure.

The third phase, the removal of the reactor core, is by far the most expensive and most technologically challenging, requiring remote robotic handling of materials. As with phase II, the economic incentive is to delay the work until it is no longer safe to do so, and in Britain, this is expected to result in a delay of 135 years.

At the end of phase III, the ideal is that the land can be released for unrestricted use, in other words, the level of radioactivity is no higher than in uncontaminated ground. In practice, this is not always going to be possible and at some “dirty” sites, such as the Dounreay site in Scotland where a demonstration fast reactor operated, use of the land is expected to be restricted indefinitely because of the high level of contamination.

Very few commercial-size plants that have operated over a full life have been fully decommissioned, so the cost is not well established. The operations required are said to have been demonstrated successfully on a small scale, but until they are applied to a large-scale plant, the process cannot be seen as proven – many processes that worked on a small scale in this area have suffered problems when scaled up to commercial size.

Much of the cost of decommissioning is accounted for by disposal of the radioactive waste generated. The cost of waste disposal in modern facilities is also not well-established, especially for intermediate level waste and long-lived, low-level waste because of the lack of experience in building facilities to take this waste.

This uncertainty is reflected in the way that estimates of nuclear decommissioning costs are quoted. Typically, they are quoted as a percentage of the construction cost (perhaps 25%). Given that the cost of decommissioning clearly only bears a limited relationship to the cost of construction, this illustrates how little is known of the costs.

A typical breakdown of the expected undiscounted cost of decommissioning might be one-sixth for phase I, one-third for phase II, and a half for phase III. British Energy was required to operate a “segregated” fund to pay for decommissioning of its plants, although phase I was expected to be paid for out of cash flow. BNFL, which owned the Magnox plants until they were transferred to the Nuclear Decommissioning Authority in April 2005, is publicly owned and treasury policy is not to allow segregated funds for publicly owned companies. British Energy assumed a discount rate of 3 percent for the first 80 years and zero after then, while BNFL assumed a discount rate of 2.5 percent indefinitely. In 2003/04, British Energy increased its discount rate to 3.5 percent.

If we assume a total cost of decommissioning of $1.8 billion – split between phases as above with phase I carried out immediately after closure, phase II after 40 years, and phase III after 135 years – the undiscounted and discounted costs will be as in Table 13.

Table 13. Illustrative costs of decommissioning (£m)

	Undiscounted	**British Energy (3%)**	**British Energy (3.5%)**	**BNFL (2.5%)**
Phase I	300	300	300	300
Phase II	600	184	151	223
Phase III	1,200	113	76	41
Total	1,800	597	527	574

Source: Author’s calculations

British Gas-cooled reactors are expected to be very expensive to decommission because of their physical bulk, which produces a large amount of waste. PWRs and BWRs are much more compact and are expected to cost perhaps only a third as much – for example, Sizewell B might be expected to cost a total of about $540 million.

Various means are used so that, as required by the polluter-pays principle, those that consume the electricity produced pay for the decommissioning. Under all methods, if the cost of decommissioning is underestimated, there will be a shortfall in funds that will inevitably have to be paid for by future taxpayers. In Britain, the forecast cost of decommissioning the Magnox plants has grown by a factor of about four in the past 20 years, even before any of the most challenging work has been carried out.

The least reliable method of collecting the funds is the unfunded accounting method under which the company makes accounting provisions for the decommissioning. The provisions are collected from consumers but the company is free to invest them in any way it sees fit, and these provisions exist as a proportion of the assets of the company. This method will only be reliable if it can be assumed the company will continue to exist until decommissioning is completed and that the assets it builds make at least the rate of return assumed. The weakness of this method was illustrated when the CEGB – the company that owned the power stations in England and Wales until privatization in 1990 – was privatized. About £1.7 billion in accounting provisions had been made by consumers, but the company was sold for only about a third of its asset value, so effectively two-thirds of the provisions were lost. The government did not pass on any of the sale proceeds to the company that inherited the nuclear power plants, losing the remainder of the provisions.

A more reliable method appears to be the segregated fund. Under this method, consumers make provisions for the duration of the plant's life, which are placed in a fund that the plant owner has no access to and which is independently managed. The funds are invested only in very secure investments to minimize the risk of loss of the funds. Such investments might yield no more than 3 percent interest. When decommissioning is required, the company that owns the plant can draw down the segregated fund. Again, there are risks as illustrated by British experience. The British Energy segregated fund did not cover stage I – by far the most expensive stage in discounted terms (about half) – while the company collapsed long before the plants had completed their operating life. The company had to be rescued by the government, and much of the burden of decommissioning will be borne by future taxpayers, who will be required to provide the funds when decommissioning is carried out.

Perhaps the lowest risk approach of provisions being inadequate would be if a segregated fund was set up at the time the plant entered service, with sufficient funds to pay for decommissioning after the design life of the plant had been completed. If we assume a life of 30 years and a discount rate of 3 percent, the required sum would be about 40 percent of the undiscounted sum. Thus, if the undiscounted decommissioning cost is about 25 percent of the construction cost, the sum that would have to be placed in the fund would be about 10 percent of the construction cost. Even this scheme would be inadequate if the plant had to be retired early, or if the decommissioning cost had been underestimated or if the funds did not achieve the rate of return expected.

Overall then, the sums required to decommission nuclear plants are likely to be high. But even under the schemes that provide the lowest risk that there will be insufficient funds to pay for decommissioning – if the costs are estimated accurately – the impact on overall costs would appear to be limited because of the impact of discounting.

Appendix 4 Status of the US projects

Southern Company

The Vogtle project appears to be the most advanced of the projects in the Nuclear Power 2010 program. In December 2009, the Vogtle project (Georgia), comprising two AP1000s, was seen as the frontrunner to get the first loan guarantees to be offered by the US government. Ironically, two previous units at Vogtle, completed in the 1980s, were among the worst cases of cost escalation then. These two units, originally expected to cost $660 million for four units, escalated to $8.87 billion for the two units actually built.

The NRC has given Southern Company permission to begin limited construction, for example on backfill, retaining walls, and a waterproof membrane at the Vogtle nuclear site.[97] The NRC also issued an "early site permit" to Southern that determines the site is environmentally suitable for the new reactors and approves emergency plans. The Georgia Public Service Commission accepted Georgia Power's, which owns 45.7 percent of the project, request to recover its financing costs for its $6.4 billion share of the 2234-MW nuclear project through "construction work in progress" beginning in 2011.[98] The assurance of cost recovery means that Southern Company has claimed it will proceed with construction even if it does not receive loan guarantees. It has also reduced the expected cost of its share, including financing up to $4.529 billion, or a total of $9.9 billion.[99]

South Carolina Electricity & Gas

Like the Vogtle proposal, the Summer (South Carolina) proposal is for two AP1000s and was on the USDOE's short-list for loan guarantees. SCE&G estimated the cost for constructing the two Summer plants alone – without transmission and finance charges – would be $9.8 billion in June 2008.[100] However, in January 2009, SCE&G increased the estimate of its 55-percent share of the costs from $4.8 billion to $6.3 billion, implying a total cost of $11.5 billion.[101] This was described as an "all-in" price and presumably includes finance costs.

Unistar

The Unistar consortium is a joint venture of Constellation Energy (Baltimore Gas & Electric) and EDF formed in 2007. EDF subsequently took a 49.9 percent share in Constellation's existing nuclear assets. Unistar has three projects: Calvert Cliffs (Maryland), Nine Mile Point (New York),

97 *Greenwire*, "NRC Grants 'Limited Work' Approval for Proposed Ga. Reactors," August 27, 2009.
98 *Platts Global Power Report*, "Georgia PSC Approves Two Nuclear Reactors by Georgia Power, and a Biomass Conversion," March 19, 2009.
99 *Nucleonics Week*, "Georgia Power Lowers Estimate."
100 *Nuclear Engineering International*, "Power Market Developments – The American Way," June 2008.
101 *SNL Power Week* (Canada), "SCE&G Discloses New Costs for Summer Nuke Expansion," January 5, 2009.

and Elmore (Idaho), all for single EPRs. The most advanced of these is the Calvert Cliffs project, which was short-listed for loan guarantees. The other two projects, Nine Mile Point and Elmore, will not be actively progressed until there is some prospect of loan guarantees being available for them. In December 2009, Unistar asked the NRC to put a hold on its application for a combined construction and operating license for Nine Mile Point.[102] The Elmore project is less advanced than the Nine Mile Point project. In April 2009, the Chairman of UniStar said Constellation has not publicly announced the estimated cost for Calvert Cliffs and that those figures are confidential.[103]

NRG

The South Texas project is for two ABWRs, to be supplied by Toshiba, which replaced GE-Hitachi as the vendor of essentially the same design in March 2008. It is the only project referencing the ABWR design, although some of the projects referencing the ESBWR may switch to the ABWR. It was short-listed for loan guarantees by the USDOE. This project attracted a great deal of publicity in late 2009. Nuclear Innovation North America (NINA) – a joint venture owned 88 percent by NRG and 12 percent by Toshiba – owns 50 percent of the South Texas project. CPS, which is owned by San Antonio city council, owns the other 50 percent. However, in October 2009, CPS announced its wish to reduce its stake to between 20 and 25 percent,[104] and by December it was investigating the possibility of exiting completely. This was after it emerged that Toshiba's (the vendor) cost-estimate for the expansion project was about $4 billion higher than the $13 billion estimate CPS had given city officials. CPS filed suit on December 6 asking the court to clarify its rights if it pulled out of the deal. The dispute escalated on December 23 when NINA filed a suit that CPS was in breach of contract and should lose the hundreds of millions of dollars it had invested. CPS filed a counterclaim hours later for $32 billion, claiming that NRG and Toshiba had lured CPS into the project through "fraudulent, defamatory and illegal conduct" and had then tried to push CPS out.[105] In October 2009, it emerged that the cost estimate for the two South Texas ABWRs was about $17 billion, including financing. No up-to-date estimates without financing costs are available.

TXU

102 *Nucleonics Week*, "UniStar Puts Further Hold on Nine Mile Point-3," December 10, 2009.

103 *Daily Record* (Baltimore), "Constellation Energy CEO: French Firm Won't Influence Baltimore Gas & Electric Co.," April 28, 2009.

104 *Nucleonics Week*, "NRG 'Perplexed' as CPS Explores Exiting Plan for New Texas Reactors," December 10, 2009.

105 *San Antonio Express*, "Mayor Calls for Meeting of Reactor Partners," January 5, 2010.

The Comanche Peak (Texas) project is the only proposal for the APWR. It was on the first USDOE short-list for loan guarantees but was subsequently relegated to first reserve. No construction cost-estimates for the Comanche Peak project have yet been published.

Exelon

In November 2008, Exelon effectively abandoned the ESBWR for its Victoria site (Texas), where two units were planned, and was reported to be looking at alternative designs.[106] In June 2009, Exelon announced it was deferring its Victoria project for up to 20 years, although it was continuing with the Early Site Permit process.[107]

Dominion

The North Anna project was one of the first to be announced and was originally expected to use the Canadian ACR-700. However, in 2005, Dominion announced it was abandoning the ACR-700 in favor of the ESBWR. In January 2009, Dominion announced it could not agree terms with GE-Hitachi for supply of the plant. Dominion announced that it would "use a competitive process" to see if vendors could provide a reactor for North Anna-3 "that can be licensed and built under terms acceptable to the company."[108] Dominion expects to make its decision about a supplier by the end of the first quarter in 2010.

Entergy

In February 2009, Entergy asked the NRC to suspend reviews of its ESBWR applications at Grand Gulf (Texas) and River Bend (Louisiana) because of concerns about rising prices.[109] Entergy Chairman and CEO James Leonard said that the company "hit a brick wall" in negotiating an engineering, procurement, and construction contract with GE Hitachi for the ESBWR because the price rose to upward of $10 billion, which he called well beyond the original cost expectation.[110]

Duke

Duke's Lee (South Carolina) project is for two AP1000s. In September 2009, Duke said it expected to begin operation of the first unit in 2021 and the second unit in 2023 – three years later than

106 *Nucleonics Week*, "Exelon Drops ESBWR, Looks at Other Reactor Designs for Its Texas Project," November 27, 2008.

107 *Greenwire*, "Exelon Suspends Plans for Texas Plant," July 1, 2009.

108 *Nuclear News*, "Sales Talks Stall with Entergy, Dominion," February 2009.

109 *Nucleonics Week*, "Entergy Revises Construction Plans, Looks again to Acquisitions," February 26, 2009, p. 1.

110 *Nucleonics Week*, "ESBWR Design Certification Rule To Be Completed in September 2011," November 12, 2009.

originally planned.[111] Duke Energy estimated in November 2008 that the overnight costs for the two-unit Lee station would be $11 billion – double its previous estimate.[112]

Progress

The Harris (N Carolina) project and the Levy (Florida) projects are both for two AP1000s. Progress has not been made on a commitment to building these units. Progress' tentative plan is to begin commercial operation of the first of the two planned Harris units in 2019 and the second in 2020. However, with lower demand growth than forecast, Progress may choose to be partners in either Duke's or Dominion's projects. The Levy plants' timelines have also been pushed back, from completion in 2016/17 to 2019/20.[113] Nevertheless, Progress Energy has been authorized to collect nearly $207 million for construction and associated work on Levy-1 and -2. This translates to an additional $5.86 per month for the average customer.[114] In February 2009, Progress estimated the construction cost of Levy would be $14 billion, excluding transmission and connection costs of $3 billion.[115]

AmerenUE

Ameren announced that it would withdraw its EPR project at Callaway (Missouri), since "the current legislation will not give us the financial and regulatory certainty we need to complete this project."[116]

DTE Energy

The DTE Energy project is for one ESBWR unit at the Fermi (Michigan) site. It is reported that the cost would be about $10 billion, but it is not clear what this cost includes.[117]

PPL

PPL's Bell Bend (Pennsylvania) project for a single EPR is a joint venture between PPL as the main partner and Unistar. The website for the project states that the cost of the project would be $13–15 billion, including escalation, financing costs, initial nuclear fuel, contingencies, and reserves.[118]

Amarillo

111 *Nucleonics Week*, "Duke May Push Back Startup of Lee Units," September 10, 2009.
112 *WNN*, "Duke Raises Cost Estimate for Lee Plant," November 7, 2008.
113 *Inside NRC*, "Potential AP1000 Buyers Unsure If NRC Design Finding Will Cause Delays," October 26, 2009.
114 *Nuclear News*, "The Florida PSC Approved Rate Recovery for New Reactors," November 2009.
115 *Nuclear News*, "EPC Contract Signed for Two AP1000s," February 2009.
116 Ameren, "AmerenUE Requests Sponsors to Withdraw Missouri Clean and Renewable Energy Construction Bills in General Assembly," press release, April 23, 2009**,** http://ameren.mediaroom.com/index.php?s=43&item=634.
117 Tina Lam, "DTE Applies for Another Nuclear Plant," *Detroit Free Press*, September 19, 2008, http://www.freep.com/apps/pbcs.dll/article?AID=/20080919/NEWS05/809190398.
118 http://www.bellbend.com/faqs.htm.

The Amarillo project is for two EPRs and is also a joint venture with Unistar, in this case, with Amarillo Power. A combined COL had not been applied for by the end of 2009.

FPL

The Turkey Point project is for two AP1000s. In November 2009, the Florida Public Service Commission (the state utility regulatory body) approved FPL to begin collecting the construction cost of these two units from consumers in 2010.[119] The commission has approved FPL's recovery of $62.7 million in costs.[120] FPL told the Florida Public Service Commission that it forecast an overnight construction cost for Turkey Point in the range of $3,108–4,540/kW.[121] However, in September 2009, FPL said the expected range of costs had increased from $12.1–17.8 billion to $15–18 billion and, as a result, the completion dates were likely to be pushed back from the 2018 and 2020 dates already announced.[122]

TVA

The Tennessee Valley Authority is very different to other US utilities because it is 100 percent owned by the federal government. As a result, it is not subject to the state-level authority that other utilities are. It also has better access to capital and has no concerns about its credit rating. It therefore does not require (and is not eligible for) federal credit guarantees. It is therefore not a coincidence that it has been at the forefront of efforts to restart nuclear ordering. The prospects for its two planned AP1000 units at the Bellefonte site – one of the earliest identified projects under the Nuclear Power 2010 program – have been clouded by the proposal by TVA to complete two partially built units, on which work was stopped in the mid-1980s. In December 2009, TVA published an environmental impact statement for different expansion plans, but none of these included a second AP1000 unit for Bellefonte, so it would seem the second unit is effectively cancelled.[123] If the construction permits for the partially built units can be reinstated, completing these may be a much cheaper way to meet demand than building a new unit. TVA has estimated the overnight construction cost for the two AP1000 units would be $5.6–10.4 billion.[124]

119 *Nuclear News*, "The Florida PSC Approved Rate Recovery for New Reactors," November 2009.
120 Tenders Info, "United States: Florida Nuclear Utilities Recover Expansion Costs," October 22, 2009.
121 *Nuclear Engineering International*, "Power Market Developments."
122 *Nucleonics Week*, "FP&L Continuing with Plans to Build Reactors, but May Change Schedule."
123 *Nuclear News*, "TVA Announced the Issuance of Its Bellefonte Draft EIS," December 2009.
124 *Chattanooga Times*, "Estimates Rise."

Glossary and list of abbreviations

BWR	Boiling water reactor
CCGT	Combined cycle gas turbine
CEGB	Central Electricity Generating Board
COL	Construction and Operating License
CTBT	Comprehensive Nuclear Test-Ban Treaty
DOE	US Department of Energy
EIA	Energy Information Administration
EPACT	Energy Policy Act
FBR	Fast breeder reactor
GCR	Gas-cooled reactor
GDA	Generic Design Assessment program
HWR	Heavy water reactor (including Candu)
IAEA	International Atomic Energy Agency
IDC	Interest during construction
MTCR	Missile Technology Control Regime
NII	Nuclear Installations Inspectorate
NINA	Nuclear Innovation North America
NPT	Nuclear Nonproliferation Treaty
NRC	US Nuclear Regulatory Commission
O&M	Operations and maintenance
Overnight cost	The construction cost of a nuclear plant including the cost of the first fuel load but excluding any financing charges
PIU	Performance and Innovation Unit
PWR	Pressurized water reactor
RBMK	(Russian reactor design using graphite and water)
START	Strategic Arms Reduction Treaty
Turnkey	A fixed price contract covering the design and construction of the entire plant
WWER	Russian PWR