

THE ECONOMIC POTENTIAL OF FUTURE NUCLEAR BUILD

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1. INTRODUCTION

1.1. AN ENERGY CRISIS LOOMS

It has long been predicted that the world is heading towards an energy crisis. During the last century the steady increase in the standard of living in the West has required a vast increase in energy consumption the majority of which has been produced from fossil fuels¹. If it were not for the continual improvement in prospecting and extraction technologies, the usable reserves of our primary fossil fuels would have been exhausted long ago. Recent estimates show that there is 40 years supply of oil and 67 years of gas remaining in proven reserves, given the current rates of usage.^[2] These figures provide false hope to some, as the global energy requirement is growing 4.3% annually, with substantial increases in Far Eastern countries to fuel their rapidly expanding economies. China's industrial sector is growing 17% annually,^[3] causing a growth in energy consumption three times the global average. Increases in the proven reserves of oil have been falling since the 1960's,^[4] and are lower than current demand², which is shown below in Figs 1 and 2.

OIL			GAS			COAL					
Reserves:	1188.6	billion barrels	Reserves:	179.53	trillion m ³	Reserves:	909.1	billion tonnes			
Usage:	29.5	annually	Usage:	2.69	annually	Usage:	2.78	annually			
Growth	1 year	Global:	+3.4%	Growth	1 year	Global:	+3.3%	Growth	1 year	Global:	+6.3%
		China:	+15.8%			China:	+19.0%			China:	+14.6%
	10 year	Global:	+18%		10 year	Global:	+29%		10 year	Global:	+27%
		China:	+212%			China:	+235%			China:	+58%

Figure 1: 2004 estimates for the global reserves and usage of the three fossil fuels, with growth rates (2003 to 2004 and 1994 to 2004) for China and the world average.^[2]

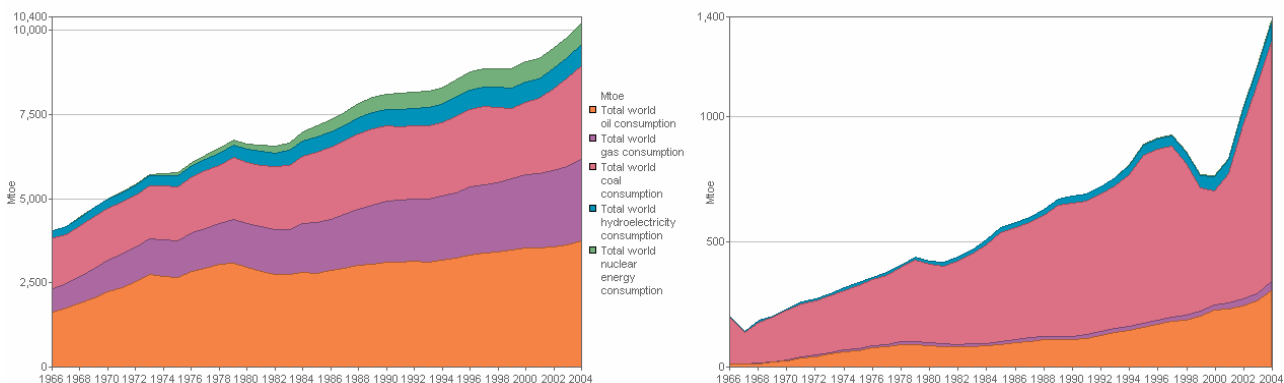


Figure 2: Total energy consumption in million tonnes of oil equivalent between 1966 and 2004 from the five major sources, both globally (left) and in China (right).^[5]

¹ World energy usage has increased five-fold since 1950, with 80% produced from fossil fuels.^[1]

² Within the past 10 years, proven oil reserves grew 16.8% and gas reserves grew 25.6%, both at least 5% lower than the growth in energy consumption over the same period. Over the past 10 years, oil reserves grew by 171 billion barrels, whereas 274 billion barrels have been consumed.^[2]

Two thirds of the global electricity market is served by fossil fuels, with only 19% generated by renewable sources - wind, solar and hydroelectric - and 16% by nuclear.^[7] This does not reflect the true balance of energy supplies however, as the electricity market comprises only around one third of total energy consumption. Many industries require process heat for operation, for example in metal and oil refining; the majority of which comes from burning fossil fuels. The largest single sector of energy usage - transport - also uses fossil fuels almost exclusively, being 97% based on oil.^[1] These markets dramatically elevate the global use of fossil fuels, so that renewables and nuclear are used for only 6% each of the global energy requirement.

Given the present rate of growth, the energy usage of China would exceed that of the current leading consumer - the US - within just 4 years, adding over 1 billion tonnes of oil equivalent to the annual global total. Although China has invested in nuclear power, its nuclear capacity is dwarfed by the escalating energy requirements, 2.2% of their electricity³ is produced from nuclear, with plans to only increase capacity to 5.5%⁴.^[8] Even the countries which have invested most heavily into alternative supplies for their electricity - France (87% nuclear^[8]) or Denmark (20% wind^[9]) - still rely heavily on fossil fuels due to the transport and process heat requirements.

Predictions of when a resource will simply run out ignore the complexities of supply and demand, and tend to give unfounded claims. In the 1950's the Hubbert Peak model was proposed, stating that the rate of production and extraction of a limited resource would follow the shape of a bell curve, rapidly increasing to a transition point, after which production would then fall off as sharply as it had once risen. The socio-economic ramifications of such a decline in oil production would be severe; the price of crude oil would rise until the care free usage enjoyed today would be beyond the means of ordinary people. The world will not wake up one day to find no oil left in the ground, the predestined reduction in usage will happen gradually, and begin well before the 40 years predicted by consumption rate.^[6]

This model gained favour when it was successfully used to predict the downturn in US production of oil in 1970. When applied to global production, dates of this turning point in oil production have been falsely predicted as 1989 and 1995. Current predictions place the date from 2007 to 2020, based on the historical usage of oil shown in Figure 3 and the recent downturn in new prospective extraction projects, leading to an expected glut in production within four years.

³ Less than 1% of total energy consumption.

⁴ Reactors either under construction, or with planning and funding secured.

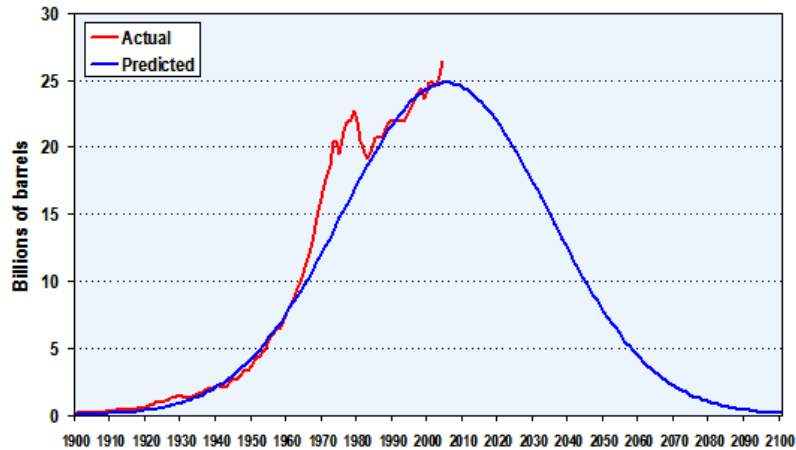


Figure 3: Actual and predicted oil consumption, based upon the Hubbert Peak.^[10]

The problems with continuing to depend solely on fossil fuels are not only those of exhausting a limited supply; the environmental consequences of burning fossil fuels are becoming alarmingly apparent. Only within the last decade has the link between greenhouse gases and climate change become widely accepted as fact rather than speculation, as prognoses for the human toll continually increase in their severity. The effects are believed to be already apparent, with 160'000 deaths per year attributed to global warming today, and the possibility of billions of people displaced by the expansion of the world's oceans.^[11]

1.2. ALTERNATIVES

A number of alternatives to fossil fuels have existed for many decades; principally the group of renewables along with nuclear power. These are considered to be 'green' energy sources as they do not emit greenhouse gases and other pollutants from burning fuel. Although nuclear fission is strongly associated with threatening nuclear waste, proponents argue the scale of this pollution is trivial. In generating 1GWh of electricity, a next generation nuclear reactor could produce as little as 13kg of solid high-level waste⁵, compared to 500 tonnes of CO₂ for a natural gas fired power plant, or 1000 tonnes from a coal plant along with 6 tonnes of ash and 1.5 tonnes of other particulates.

⁵ Based on a 165MW PBMR producing 19 tonnes of waste annually.^[12]

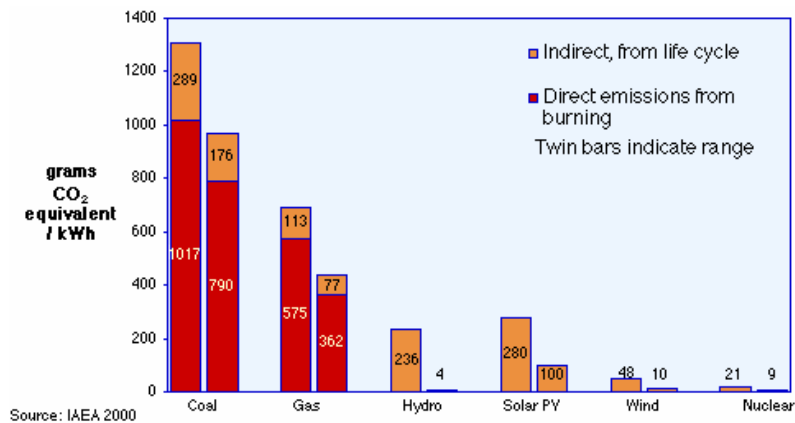


Figure 4: The range of greenhouse gas emissions from the major energy sources.^[13]

Of the four alternative fuels, Figure 4 demonstrates that nuclear can be considered the most favourable in terms of greenhouse gas emissions. The majority of energy expenditure - aside from construction of the plant and associated facilities - is in the process of fuel enrichment, which typically requires 0.7kWh of electricity for every MWh produced (0.07%).⁶ Solar cells suffer from an energy intensive manufacture process, and hydroelectric can require an enormous construction effort if an existing geographical feature is not exploited. The indirect greenhouse gas emissions of these alternative sources are still substantially lower than fossil fuels, giving a strong environmental incentive to invest in renewable or nuclear capacity.

However, none of these alternatives can be said to have made a significant impact in the global energy market as they possess some significant flaws, principal among these being cost. Fossil fuels remain dominant in most electricity markets because they are the cheapest option. The cost of electricity generation is as little as £22/MWh to £26/MWh from natural gas or coal respectively.^[15] The only renewable to match this price are existing hydroelectric dams, but this resource is unlikely to expand in the UK, as new dams would incur untold construction costs and hostility from environmental groups for the damage caused by flooding large areas of land. Wind turbines are approaching competitive prices, operating at around £37/MWh,^[15] whereas solar is as yet unviable with typical costs of around £100/MWh^[16].

These costs are in part due to the relatively immature technology of the systems, but are also influenced by the nature of the sources they utilise. Renewable sources such as wind and solar suffer from a low energy density, respectively capable of around 3MWh/m² and 1MWh/m² annually within the UK.^[17] This is combined with a low availability⁷, or capacity factor, to compound the problem of output from these sources. Solar plants typically achieve less than 25% availability,^[16] whereas wind power has been demonstrated to have

⁶ Based on 1kg of 3.5% enriched uranium, which requires 4.3SWU (at 60kWh per SWU for a gas centrifuge) and can produce 360MWh of electricity.^[14]

⁷ The fraction of time the plant is capable of operating at full capacity.

an availability of 25% to 35% on land.^[15] These compare to availabilities of over 90% for fossil fuel or nuclear based plants. With the combination of energy density and availability, it would be estimated that to generate the output of a modern nuclear plant (15TWh/yr), a wind farm measuring nearly 4km by 4km ($14 \cdot 10^6 \text{m}^2$) would be required.

These renewable sources also suffer as they utilise an unpredictable energy source. In nominal operation, a fossil or nuclear plant will operate at either a constant load, or will follow the trend of demand. Renewables are subject to the whim of mother nature, and can be hampered by clouds or low wind at any time. This is not suitable for a major contribution to the national grid, as the ability to match the base-load demand can not be guaranteed at all times. Large investments in renewable plants therefore require spinning reserve; conventional plants running at part load, whose output can be rapidly increased to meet a surge in demand. This adds significantly to their cost, contributing between 20% and 30% to the cost of generation from wind power.^[15]

1.3. THE NUCLEAR ALTERNATIVE

In contrast to renewables, nuclear power has been economically competitive with fossil fuels for decades. Nuclear power was among the cheapest methods of generation within the UK in 2004, estimated at £22.60/MWh.^[15] A gas turbine with a combined cycle (CCGT) was cheaper at £22.00/MWh without a provision for carbon tax, rising to £25.70/MWh with a pessimistic estimate for the duty on carbon emissions⁸.

It is expected that nuclear plants would be the cheapest source of electricity at the time of writing this report or in the near future as fossil fuel prices rise. Nuclear power benefits from a low dependence on the cost of fuel, which makes up less than 20% of the generation cost. Comparing this to gas or coal fired plants, for which fuel can make up 60% of the final electricity price, nuclear power would become cheapest with a small rise in fossil fuel prices from their 2004 levels, as shown in Figure 5. The uranium market is by no means stable, exhibiting large fluctuations as seen in the price of crude oil. However, the volatility in this price does not have the profound effect seen in gas or coal fired plants however due to the comparatively low consumption of nuclear fuel.

⁸ A conservative figure of £30/tonne of CO₂ was given, equating to an approximate 4% tax on revenue (14.6kg of CO₂ per GJ of natural gas, giving 52.6 tonnes per GWh, or £1'600 tax on -£40'000 worth of electricity)^[15]

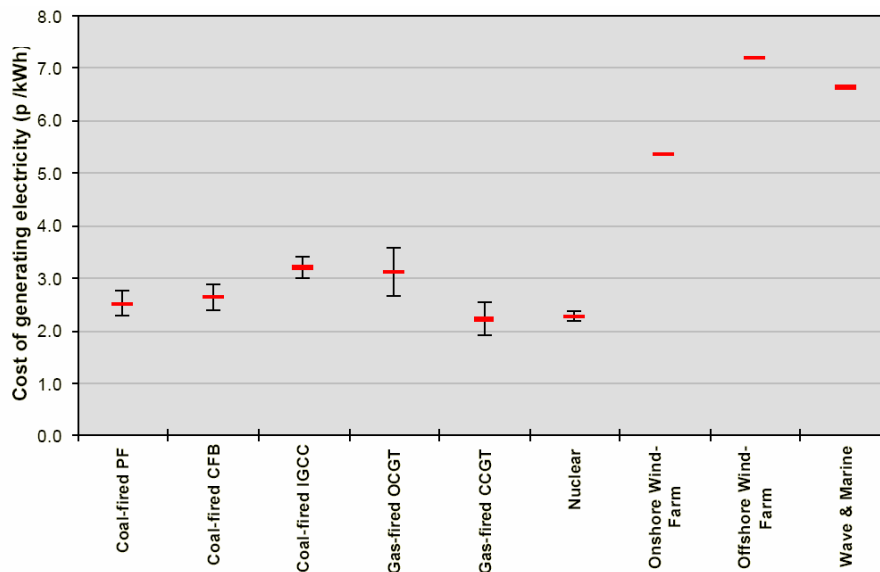


Figure 5: Generation costs from various sources with tolerance bars for $\pm 20\%$ change in fuel prices.^[15]

It seems unlikely that the reluctance to begin a new build of nuclear power is primarily because of problems with the economics of reactors. Only the oldest generation of plants in the UK fare poorly in comparison with fossil fuel plants, and new plants would likely be cheaper than existing technology in the long run.

Although generation costs are competitive, the nuclear industry has been in serious financial difficulty recently because of the huge cost of cleaning up and decommissioning old reactors. These costs were never accounted for during the operating lifetime of these early reactors, leading British Energy to the brink of collapse because of its billions of pounds in liabilities. The technical requirements of decommissioning Magnox reactors were not given great consideration when they were designed, creating a more difficult and costly task than will be posed by present or future reactors. Taking this into account from the beginning of a new construction would however add only ~5% to the capital outlay, meaning that dismantling new reactors would not be a problem for future reactors.

Waste disposal is another cost the nuclear industry is saddled with, which other forms of generation do not have to consider. The gaseous waste of fossil fuel plants is easily disposed into the atmosphere where its effects are not immediately or locally noticeable, and thus it is considered acceptable to continue this practice. Nuclear waste on the other hand is solid, quantifiable and potentially dangerous in a number of ways. Since the advent of commercial nuclear power, the safe disposal of this waste has been a mandatory requirement of reactor operators. Free options, such as discharging radioactive gases to the atmosphere, or dispersing waste into the sea have not been an allowable option.

Governments are slowly realising that the ecological cost of commercial actions can only be accounted for by assigning a financial cost to that action. Nuclear power is already

subject to this newer style of socio-economics, as strict fines are imposed on operators who allow discharges into the environment. Although the dumping of nuclear waste would never be permitted legally, even if such laws were not in effect it would not make commercial sense to do so, as the fines incurred would greatly exceed the cost of managing the waste in a more responsible manner.

The introduction of a carbon tax would allow for the environmental cost of using fossil fuels to be more accurately represented. By assigning a value to 1 tonne of CO₂ discharged, there would be a financial incentive for companies such as power plant operators to reduce their emissions. At present, Europe operates an emissions trading scheme, whereby companies are set an upper limit to their emissions of various pollutants. If they emit more than this quota in a given year, they must buy the rights to do so from another company who has emitted less than their quota. Such a system is seen as a step in the right direction, but it still allows a power plant to dispose of its CO₂ free of charge, so long as it meets government set targets. The move to taxing the absolute amount of CO₂ emitted has been recommended to the UK government by the Royal Society, on the grounds that it would promote the long-term development and usage of cleaner technologies, while achieving a rapid reduction in the emissions of greenhouse gases.^[18] The government of New Zealand has taken a lead on this issue, and plans to introduce a carbon tax of ~£6 per tonne in 2007.

The cost of waste disposal is accounted for by a 5%⁹ levy on the electricity generated by current nuclear power plants, a figure which is expected to be reduced with newer and less wasteful designs. In comparison, a £6/tonne tax on CO₂ emissions would add 3-6%^[15] to the cost of fossil fuel generated electricity, as seen in Figure 6. Even with the cost of waste disposal included in nuclear, it has proven to be competitive with fossil fuels. The introduction of a carbon tax would promote nuclear power for being an essentially carbon-free means of generating power, giving a financial incentive that would perhaps distinguish nuclear power as the cheapest form of electricity generation available.

⁹ £1.25/MWh is estimated as the allocated cost of waste disposal for current reactors.

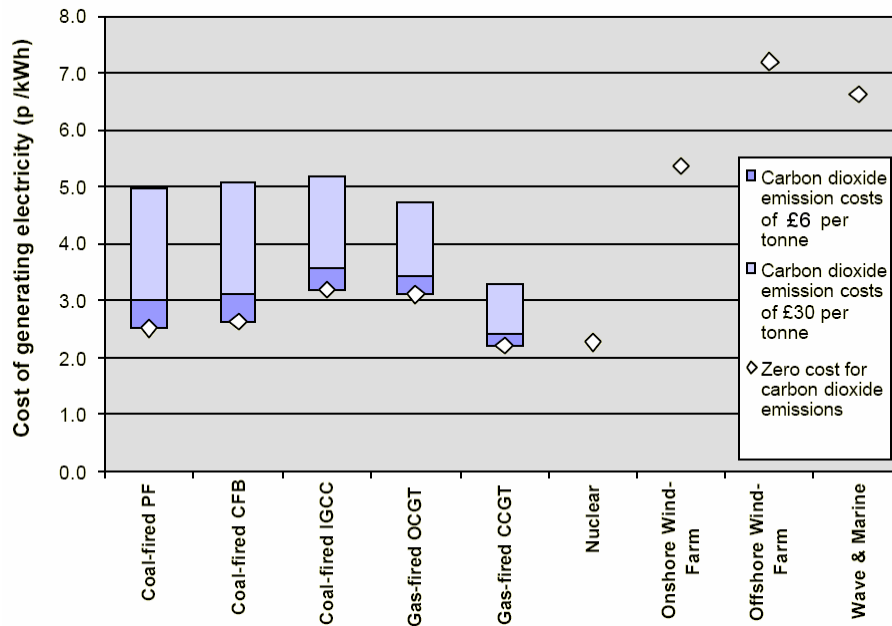


Figure 6: Generation costs from various sources with an indicator of costs with the introduction of a carbon tax. £6/tonne is the initial tax to be applied in New Zealand, £30/tonne is the estimated cost of sequestering carbon underground.^[15]

The first section of this report gives an analysis of the costs involved in electricity generation. A prediction of the costs associated with a typical nuclear, oil and coal plant are given as reference points. New reactor designs from Generation III, III+ and IV were considered, and those for which financial data could be found, a prediction of the costs was made.

2. REACTOR ECONOMICS

2.1. INTRODUCTION

In order to evaluate the profitability of different reactor technologies, the costs incurred by each design had to be compared. It was paramount that the evaluation was made on a fair and level basis, otherwise no useful conclusions could be drawn. This demand for uniformity across the various costs between reactors was the cause of much data being discarded, and narrowed the final analysis that was possible.

The economic information provided on a given reactor design typically fell into three categories: promotional literature, speculative estimates and financial appraisals. Only the third type of information proved useful to this investigation, because of the requirements for a fair and justified comparison. It would be unfair to say that figures provided by manufacturers such as Westinghouse or AECL were untrue, but they were presumed to be based on unrealistic assumptions. When they could be compared against an independent review, the promotional figures were always under estimates. They would also serve no purpose, as promotional literature tended to simplify its analysis, providing only the final generation cost (perhaps with a breakdown into specific components), with no explanation of the underlying assumptions used. Estimates made by unqualified commentators were also disregarded, although there was occasion to use rule of thumb estimations when other information was scarce or contradictory.

A standard list of costs was produced that gave the major areas of expenditure associated with running the reactor, and values for each plant type were estimated where possible. With a full assessment of these costs, the total cost of generation could be plotted against operating time¹⁰. This would allow for a prediction to be made of the reactor's potential importance in the UK market, and the alteration to electricity prices if a fleet of such reactors were built.

¹⁰ More detail is given later in Chapter 4.3.

2.2. REACTORS UNDER CONSIDERATION

The 'classes' or generations of reactor type were considered for analysis:

- **Gen II:** The commercial power reactors in operation today.
Typically built since 1970, including PWR, BWR and CANDU designs, Generation II reactors comprise nearly all the reactors in operation today. The UK has 14 AGR reactors and 1 PWR¹¹ that are Generation II designs.
- **Gen III & III+:** Advanced light water reactors and evolutionary designs.
Generation III are the latest extension to existing reactor designs, the first of which has come into operation within the past 10 years in Japan, with 4 more under construction.^[2]
Generation III+ are further evolutions to the PWR and BWR designs, along with the introduction of the HTR (high temperature reactor). These will see first-of-kind construction within the next 5 to 10 years.
- **Gen IV:** Revolutionary reactor concepts slated for 2030 and beyond.
This generation contains six designs selected from hundreds as the most likely to meet the requirements of the future energy demands. These consist of a mix of thermal and fast reactors, with gas, water or liquid metal coolants.^[3]

An existing Generation II reactor was included to give a basis for comparison. These reactors form the majority of the UK nuclear capacity and thus would be expected to have an influence on the current electricity market. By the same reasoning, a modern Combined Cycle Gas Turbine (CCGT) and a Pulverised Fuel (PF) coal plant were included, as these plant types are common throughout the UK.^[4]

GENERATION III:

From Generation III, two reactor types are being investigated as potential replacements for the countries fleet of AGR reactors; the AP1000 from Westinghouse and the ACR-700 from Atomic Energy of Canada.^[5]

Other designs include the European Pressurised Reactor (EPR) and the Advanced Boiling Water Reactor (ABWR). The EPR was chosen out of four candidates for a new construction project in Finland, and work has begun on building the first reactor of this design.^[6] The ABWR is the most developed Generation III design, with three units operating in Japan, and a further three under construction in Japan and Taiwan.^[7] These reactors are only

¹¹ Sizewell B can be classed as Generation III due to advanced digital monitoring and other modifications made from the standard PWR design it is based on, which would otherwise be Generation II.^[1]

mentioned in passing reference, as they are not currently under consideration for construction within the UK.

AP1000:

The AP1000¹² is an enlarged version of Westinghouse's AP600 design which was certified as fit for construction by the US Nuclear Regulatory Commission in 1998, after 1300 man-years of design and 6 years of approval. The AP600 has never received any firm orders for construction as it was superseded in 2004 by the AP1000. Described as the 'logical extension' of the AP600, it would be capable of almost double the power output without significantly increasing construction cost or modifying the existing design.^[8] The reactor is an advanced PWR, with a focus on simplifying the design to improve economics and introducing passive safety systems.

The simplification results in a design containing approximately half the number of components¹³ of a standard PWR, contained in a building "small enough to fit in the car-park of Sizewell B".^[1] Modular construction techniques could be employed, allowing for many components to be fabricated in a standard factory. These changes translate to an estimated lower capital cost and shorter build time, both of which have a significant effect on the generation cost from the reactor.

Rather than relying on active safety systems which require complex and redundant intervention mechanisms, an AP1000 would use underlying physics to provide a safer and less expensive system. Forces of gravity, convection and natural circulation are exploited so that no operator intervention is required to shut down a supercritical plant, and reliability of the safety systems is assured.^[1]

ACR-700:

The ACR-700, and its successor the ACR-1000¹⁴ is an advancement of the CANDU design that has been successfully operated in 7 countries worldwide.^[9] The ACR is a hybrid of PHWR and LWR designs using a heavy water moderator and light water coolant. It builds on the strong points of the original CANDU design, namely the ability to refuel the reactor on load and the high utilisation of uranium¹⁵. Simplifications to the original design and the use of modular components lead to a shorter construction time, estimated to be comparable to that of the AP1000. Fuel utilisation is improved and waste production reduced by the use of slightly enriched uranium, which would also be required by the introduction of a light water coolant. The ACR builds on the passive safety systems that are present in existing CANDU designs, combined with active shutdown and cooling

¹² Advanced Passive 1000. It should be noted that actual capacity of models purchased averages at around 1150MWe.

¹³ Widely promoted figures are: 50% fewer valves, 35% fewer pumps, 80% less pipe and 85% less cable.

¹⁴ Advanced CANDU Reactor, producing on average 1100MWe.

¹⁵ CANDU reactors use about 15% less uranium than a PWR per GWh generated due to an improved neutron economy.^[9]

measures. As with CANDU reactors, it would be comparatively simple to maintain the core reactivity due to long doubling times introduced by the heavy water, which also acts as a passive heat sink in the event of a LOCA.^{[10][11]}

GENERATION III+:

From Generation III+, the reactor design that is furthest along the development cycle is the PBMR, or Pebble Bed Modular Reactor. This is a radical departure from conventional power reactors, being from the HTR (high temperature reactor) family, and with each reactor producing only 165MWe. The principles of the reactor design have been the subject of research for decades in the US and Germany, with the proposed design being a collaborative effort between two companies from the US and South Africa.

The size of each PBMR reactor is considered an advantage, as it allows for the construction period to be staggered, so that initial reactors can be running and generating revenue to help fund subsequent construction. It also gives the potential to greatly reduce the capital costs required, as smaller core components would allow for highly modular and standardised construction techniques.

The Chairman of Exelon¹⁶ has claimed the PBMR could be built for 40% less than a Generation II reactor.^[12] This is however, the closest to solid information that is freely available on the PBMR economic performance. Any evaluations that have been made would be restricted access as such information is commercially sensitive.^[13] To provide a comparison, a similar claim was made about the ACR-700 design, stating that “the capital cost [could be] reduced by up to 40% compared with existing designs”.^[14] It can be seen later on that this claim was grossly exaggerated, and a reduction of 10% was considered more likely.

Regrettably, the PBMR design was therefore not included in the analysis. This also rendered the intended final section of this report unviable, which would have been the integration of nuclear and hydrogen production. This proposed combination required a HTR design to provide enough process heat for either high temperature electrolysis or the thermochemical decomposition of water.

Other Generation III+ designs are in earlier stages of development than the PBMR, with no possibility for a meaningful economic analysis to be undertaken. The same situation was true to an even greater extent for Generation IV reactors. These reactors are typically limited to an artists impression of the general core layout, and proposed operational characteristics such as coolant temperatures and core dimensions. With no detailed design plants for the balance of plant, there are no existing economic analyses to use as a basis in this report.

¹⁶ Exelon are working together with Eskom in developing the PBMR design.

To conclude, the number of reactors under consideration was much smaller than originally intended. Detailed information relating to newer designs is commonly restricted, and was only made available due to the assistance of personnel within the nuclear industry. For this reason, the analysis was extended to include non-nuclear plants for a comparison between nuclear and the other major contributors to the UK grid.

The five plant types under consideration were as follows:

- A typical Generation II reactor, representative of an AGR or PWR design.
- A PF coal plant and CC gas turbine, both of which are used widely in the UK.
- The Westinghouse AP1000 - an advanced PWR reactor.
- The ACR-700 from Atomic Energy of Canada Ltd. - an advanced heavy & light water hybrid design.

2.3. ANALYSIS OF PLANT COSTS

The costs associated with running a power plant could be broadly categorised as fixed and variable costs. The fixed annual costs would occur irrespective of the number of hours the plant was in operation, for example:

- Capital required for construction
- Decommissioning of nuclear reactors
- Operation & maintenance

Variable costs would depend on the electrical output of a given year, such as:

- The acquisition of fuel
- The possibility of emission taxes for fossil fuel based plants
- Reprocessing spent fuel, and disposal of waste arising from a nuclear reactor

For nuclear reactors, the initial capital investment required for plant construction is very high. A nuclear reactor costs in excess of £1000 per kW of installed capacity, meaning a typical 1GW plant would require £1bn of investment. This investment can be financed from a number of sources, equity from the plant owner combined with debts with commercial banks, governments or the World Bank. The cost of financing this investment

comes from the need to repay these loans, and provide a suitable return on the equity provided by the owner.

The interest rate that would be applied to each of these loans would vary between projects, as would the rate applied to individual loans within a given project. A common 'discount rate' was applied to the capital repayments of every plant type to give a fair comparison between projects. The discount rates applied in other analyses typically vary between 5%-10%, thus 8% was chosen as a mid-point. Repayments of the capital were assumed to be spread over the operating lifetime of each plant.

When a nuclear reactor was being considered, an allowance was made for the eventual decommissioning of the reactor, typically made via annual contributions made during the operational life of the reactor. A lower discount rate of 4% was used for these payments towards decommissioning, as the money would not be required up-front and so could accumulate in a bank account. BNFL uses a 2% discount rate for treating future liabilities such as decommissioning, while Magnox Electric uses 3%.^[15] As a general guide, the decommissioning costs were assumed to be 5% of the capital costs when not explicitly stated.

Fixed operation and maintenance (O&M) costs constitute the generic costs that would apply to any industrial plant, such as land costs, staff salaries, insurance and management overhead.

The variable costs under consideration were summarised as fuel and emissions costs. For fossil fuel based plants this was simply taken as being the cost of purchasing fuel. The effect of a carbon tax was considered, although not used for the reference case as this policy is not under imminent implementation by the UK government.

At present, the only emissions of CO₂ that have a financial value attached to them are those emitted after the government set limit for a particular facility has been exceeded. Thus, any power plant that meets its target for reducing these emissions will not be burdened with having to pay for its carbon emissions. It was considered that this policy may be changed by future governments, and so an analysis with carbon tax included in the generation costs would allow the impact of this policy to be assessed.

For nuclear reactors, the fuel costs were split into front-end and back-end costs. The front-end combined the costs of purchasing uranium, enrichment, and fabrication of the fuel elements. Back-end fuel costs are associated with reprocessing spent fuel, and disposal of waste arising from the reactor. It was assumed that spent fuel would be reprocessed in line with current UK policy, rather than simply disposed of as with the US backed once-through cycle.

These reactor costs were expressed in two forms for comparison:

- £/kW - the initial or annual expenditure per kW of installed capacity.
- £/MWh - the contribution of to the final generation price.

The annual expenditure per unit capacity was divided into the fixed and annual costs. With this information, the total cost of producing electricity from a particular plant could be plotted against the number of hours of operation. The costs to the overall generating price were broken down further into individual components, so that the impact of each cost could be seen.

2.4. FINANCIAL APPRAISAL METHODS

The financial appraisal of competing projects can be performed in several ways, each method giving its own slant on the relative merits of each project. Each will give an indication of the financial performance of a project, based on predictions of the profits and expenses that it will incur. They are however, not a guarantee that a particular project will give a certain level of returns, as they are based on predictions of the future economic climate, such as inflation rates and the expected profits. However, so long as these assumptions are kept constant between projects their relative performance can be compared, allowing the most successful project to be chosen.

A typical scenario to be considered would start with a large initial capital investment being made to fund the construction of a nuclear reactor. Once construction was complete, there would follow several years of return on this investment, money made from selling electricity offset by the running costs of the plant. As an example, an initial investment of £1bn is made, and from the end of that year onwards returns of £100m per year are produced.

The most used methods in industry^[16] are comparing the payback, average rate of return and internal rate of return between projects. The example given above will be used to help explain the premise behind each of these terms:

PAYBACK:

The time taken for the original investment to be covered by the returns. A shorter payback period is desirable, as you risk losing your investment for a shorter period of time, and the value of money is higher earlier into the project due to inflation. With £1bn investment and £100m/year return, the payback would be 10 years. This method of

evaluation is short sighted, as it only considers the early years of the project and ignores any change in the returns once the payback period is over.

AVERAGE RATE OF RETURN (ARR):

The average annual return as a fraction of the initial investment. In the example case, this would be 10%. This method loses all timing information as the returns are averaged over the lifetime of the project.

INTERNAL RATE OF RETURN (IRR):

This is the most complex method as it considers the value of money with time. Money earned in the future will be worth less as the effect of inflation devalues it with time. Therefore, all returns are considered in terms of today's value by applying a discount factor to all future returns. This factor is given as $1/inf^y$ where *inf* is the average rate of inflation over the time period, and *y* is the year being considered. The rate of inflation was taken to be 2.5%¹⁷, which applied to the example would give the first year's profit a current value of £98m, and the tenth year as £78m. The IRR is found by varying the inflation rate until the sum of the returns over the lifetime is equal to the initial investment, and thus the project breaks even. This gives a measure of the tolerance a given project has; the one which can withstand the highest inflation rate and still break even will be most likely to succeed. This method gives a more accurate impression of a projects relative performance, as all revenue is considered in today's terms. As with other methods it does not give an absolute value for a project's profitability, as this would require predicting an inflation rate for the future and giving the final profit or loss at the end of the project lifetime. For the given example, the IRR would be 0% with a 10 year lifetime, as the payback period is 10 years, and so any reduction in future revenue would mean the project would return a loss. For a 20 year lifetime the IRR is 7.2%, or over 40 years it is 8.9%.

A factor that was not explicitly considered in the financial appraisal was the length of time required to construct each particular plant. A longer construction time would have an impact on the cost of financing the construction, even if the total capital required to build the plant remained the same. Consider two plants: a gas turbine which takes 1 year to go from signing the contract to producing electricity, and a nuclear plant that requires 3 years for the same process.

Although the initial capital would not all be required in the first year of nuclear construction, the funds would have been secured to prevent the risk of running out of

¹⁷ The inflation between Jan 1995 and Jan 2005 was 27.5%_{[17][18]} - giving an annual rise for the past decade of 2.46%.

capital half way through construction. If all other factors were the same, the payback period on the nuclear reactor would be 2 years longer than for a gas turbine, as revenue would be delayed by the lengthier construction. The ARR would be equal over the operating lifetimes of each plant, or would be 5% lower for the nuclear plant if the construction period was included¹⁸. The effect on the IRR would however be more notable, as all returns on the nuclear reactor would be delayed by 2 years, and thus be subjected to two additional years of devaluation from inflation. With an inflation rate of 2.5%, the current value of returns from the nuclear plant would be 8% lower than for the gas turbine built two years earlier. With a £1bn investment, and £100m/yr returns, the IRR for the gas turbine would be 20% greater¹⁹ than for the nuclear plant, just because of the delay in becoming operational.

It was believed that the effect of construction time had been factored into the cost of financing capital for each plant type. This was seen in the capital costs expressed as £/MWh, which were approximately three times higher for nuclear plants than a CCGT. Average construction times of 5 years²⁰ were expected for nuclear plants compared to a year or less for a CCGT.^[20] The effect of this on the generation price would be significant, a 3.5% decrease has been estimated for one year of construction time saved.^[1]

¹⁸ Given a 40 year operating lifetime, the 40 years of returns would be divided by the 41 year total lifetime for a gas turbine, or the 43 year total lifetime for a nuclear plant.

¹⁹ An IRR of 9.8% was calculated for the gas turbine compared to 8.2% for the nuclear plant, given 40 year operational lives.

²⁰ Sources gave 48-72 months,^[12] 55 months,^[14] and 60 months.^[19]

6. RESULTS

6.1. ELECTRICITY GENERATION COSTS

The first task to be undertaken was to perform the cost analysis of various reactor technologies as outlined in Chapter 2. Three nuclear reactors were compared against each other, and against two leading designs of fossil fuel plants. Of the nuclear reactors, one was a representative of current plants in operation while the other two - the AP1000 and ACR-700 - were reactors that have been under consideration for future construction within the UK.

A more detailed account of the information consulted to arrive at these conclusions is presented in Appendix D, with a list of references that were used.

6.2. GENERATION II

The first plant type to be considered was identified as a typical Generation II reactor such as an AGR or PWR. Although these are two very different reactor technologies, the tendency of cross-technology comparisons has been to treat existing reactors as a single group. The costs associated with these two technologies are assumed to be reasonably similar, given that the opportunity for reducing the major contributions to costs is limited.

The Generation II had the most easily identified costs of the three nuclear options studied, as these reactors are already in existence and have been operating for many years. Two major reports on the costs were made in 2004 by the *Royal Academy* and in 2003 by the *Massachusetts Institute of Technology*. In addition to these, a report entitled *The Economics of The Nuclear Fuel Cycle* was used to validate fuel and waste costs²¹.

A 1GW plant was considered, with a 40 year operational life and 85% availability²² giving 310 days a year of operation, or 7446GWh/year. The costs associated with running the reactor at full load, and the final cost of generating electricity are shown in Figure 1.

²¹ A full account of information gained from each source, with their references is contained in Appendix D

²² Nuclear plants in the UK averaged 76% load factor during 2003_[1], although this includes the 18% contribution made from Generation I Magnox reactors. An 85% capacity factor was suggested for more modern reactors.

Generation II:

Generation Costs:		
	£/MWh	
Capital:	£12.85	Capital: £1140/kW
Decom:	£0.68	
O&M:	£5.64	Annual Costs:
Fuel:	£3.70	£/kW
Waste:	£1.26	Fixed: £142.74
	£24.13	Variable: £36.93
		£179.67

Figure 1: Cost analysis for the Generation II reactor. To the left, the individual contributions to the generation price are listed. The initial construction cost is shown, with the annual costs if run at full capacity.

To summarise Figure 1, the overall cost of generation from a new AGR or PWR in the UK was estimated at £24.13/MWh. An initial capital investment of £1.14bn would be required to build a 1GWe plant, with £178m/year required to run it at full load.

This estimate of the generation cost helps to explain why British Energy came into financial difficulty during the period of 2001-04. The annual average spot prices were below £20/MWh during these three years, meaning that the country's nuclear reactors were probably unable to recoup enough revenue to cover their operating and financing costs.

The variable costs for the reactor come to £4.96/MWh, or approximately 20% of the total generation cost. This would be the value of C_B on the price-duration curve for a Generation II reactor, if there were sufficient nuclear capacity to determine the price of electricity. In 2002/03, the average spot price was £15.48, implying that the country's AGR fleet were only able to cover 36% of their capital costs²³.

The estimate of £24.13/MWh was reasonably close to the figure quoted in Chapter 1.3. of £22.60/MWh. Incidentally, that quote was taken from the Royal Academy paper that provided most of the cost estimates for this analysis. The two end results diverged primarily because of a more conservative estimate for waste reprocessing, although one third of the difference between the two values was simply attributed to the extra year of inflation added to prices in this report.

²³ Revenue after O&M and variable costs: £15.48 - £4.96 - £5.64 = £4.88/MWh. Fixed capital & decommissioning costs: £13.53/MWh.

6.3. COAL

The economic analysis of the two fossil fuel plants was treated with less rigour than was applied to the nuclear reactors. They were included to serve as a comparison with current and future nuclear reactors, and so were not the main focus of the report. As these plants have been in wide use throughout the world for many years, it was assumed that economic information regarding the plants was more easily available for other reports to work with. All the values²⁴ presented in Figure 2 were taken from the *Royal Academy report: The Costs of Generating Electricity*.^[2]

Coal PF:

Generation Costs:		Capital: £841/kW	Generation Costs:		
£/MWh			£/MWh		
Capital:	£9.95	Annual Costs:	Capital:	£9.95	Annual Costs:
O&M:	£3.28			O&M:	
Fuel:	£11.89	£/kW	Fuel:	£11.89	£/kW
Carbon:	--	Fixed:	Carbon:	£5.04	Fixed:
	<u>£25.12</u>	Variable:		<u>£30.17</u>	Variable:
		<u>£191.48</u>			<u>£229.91</u>

Figure 2: Cost analysis for a coal fired plant, provided without an allowance for carbon emissions (left), and with a notional tax of £6/tonne added (right).

Two options were given for the analyses of the fossil fuel plants, to consider the waste costs as being zero, and to have a nominal value attached to the emission of carbon dioxide. A tax of £6/tonne of CO₂ emissions was included in the second analysis presented in Figure 2, where the level of taxation was based on the carbon tax being introduced in New Zealand.

It was concluded that coal was a more expensive generation option than nuclear, requiring approximately £1/MWh more to break even. The fixed costs were 30% lower than for a nuclear reactor, due equally to a lower construction cost with no requirement for decommissioning²⁵, and to a substantial reduction in the O&M costs. However due to the vast quantity of fuel required, the variable costs were 2.5x higher for the coal plant without the consideration of carbon tax.

The variable costs were over twice those of a nuclear plant at £11.89/MWh, although this was made up in part by lower fixed costs, and so less of a need for electricity prices to rise above C_B during peak periods. However, as the overall cost of generation was higher for

²⁴ Within the Royal Academy report, £10/tonne of carbon dioxide was used as the value for a hypothetical carbon tax. The cost given per MWh was multiplied by 0.6 to reflect the different value assigned in this report.

²⁵ Within the Royal Academy report, the cost of dismantling a used fossil fuel plant was taken as being equal to the scrap value of the components, thus no cost was attributed to this.^[2]

coal, during 2002/03 a typical coal plant would have only been able to recover 3% of its capital costs.

The inclusion of a carbon tax would have a significant impact on the price of electricity from coal plants, as they emit the most carbon dioxide per unit of energy produced, 22.5kg/GJ.^[2] The base load price would increase 40% if a tax of £6/tonne was introduced, although this would not likely be reflected in the average spot prices paid in the future. With a predicted average price of £50/MWh for the year 2005/06, this carbon tax would add at most £5/MWh to the price, and so it could be expected that average prices would rise by no more than 10%. This would be because only base load prices would be affected, as there would be no need for peak prices to rise by more than £5/MWh as the fixed costs to be recovered by each plant type would remain the same. There may be an incentive for operators to retrofit their plants with improved technology to reduce carbon emissions, but for such a move to be economically sensible, the reduction in variable costs would be expected to outweigh the increase in fixed costs.

6.4. COMBINED CYCLE GAS TURBINE

As with the coal plant previously considered, all the values in Figure 3 were taken directly from the Royal Academy report.

Gas CCGT:

Generation Costs: £/MWh Capital: £3.69 O&M: £3.28 Fuel: £15.68 Carbon: -- <hr style="width: 50%; margin-left: 0;"/> £22.65	Capital: £308/kW Annual Costs: £/kW Fixed: £54.34 Variable: £122.27 <hr style="width: 50%; margin-left: 0;"/> £176.61	Generation Costs: £/MWh Capital: £3.69 O&M: £3.28 Fuel: £15.68 Carbon: £2.28 <hr style="width: 50%; margin-left: 0;"/> £24.93	Annual Costs: £/kW Fixed: £54.34 Variable: £140.01 <hr style="width: 50%; margin-left: 0;"/> £194.35
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Figure 3: Cost analysis for a gas turbine, provided with and without an allowance for carbon emissions.

This analysis gave the generation cost from gas as being the cheapest of all sources, at £2.50/MWh cheaper than nuclear power. The gas turbine was at the opposite end of the spectrum to the nuclear reactor in terms of fixed to variable costs. For a CCGT running constantly, 31% of the annual costs were required for capital repayments and O&M, compared to 53% for a coal plant and 79% for a nuclear reactor. This was due both to the large requirement of fuel costs, and the greatly reduced capital costs required to build a CCGT. On the surface, this would indicate the ideal role of the CCGT as a peaking plant, as the majority of its costs are variable, due to the high cost of fuelling the plant.

The addition of a carbon tax has a less marked impact on the generation costs of the CCGT, as natural gas contains approximately half the carbon content of coal, at 14.2kg/GJ.^[2] The effect would be to raise the variable costs of the plant by 13% to £17.96/MWh. With or without the addition of a carbon tax, the CCGT had the highest variable costs of any of the plant types considered. If a carbon tax of £6/tonne were to be introduced, the cost of generation from a CCGT would rise above that from a nuclear plant.

It was originally considered that CCGTs were ideally suited as peaking plants, due their low capital investment and high fuel costs. However on closer analysis it was seen that out of the three plants considered, the CCGT was best suited for both peaking and base load production. The CCGT had the lowest total costs of the three plants when run for the full year, £177/kW compared to £180/kW for nuclear and £191/kW for coal - when carbon costs were not included. This would imply that running a CCGT for the maximum hours possible would be more economical than to run a nuclear reactor for the same period, despite the variable costs being over 3 times higher. This is demonstrated visually in Figure 10 in section 6.3.

The Royal Academy report focussed only on technologies suitable for base load operation, and the CCGT was chosen by them as the most suitable for operating continuously due to having the lowest fuel costs for a gas turbine.^[2] Until recently, gas turbines were generally used to provide the base load capacity due to the relatively low cost of natural gas, and coal plants were typically used for peaking. Gradually over the past five years, the roles of these two plants has switched as the price of natural gas increased sharply, and coal has become favoured for base load generation while gas turbines are used as peaking plants.^[3]

To accommodate the recent shift in fuel prices, the CCGT was re-evaluated with the predicted fuel prices for 2005/06. The Royal Academy took the price of natural gas to be £2.18/Btu,^[2] whereas in Chapter 4.2 the annual average for 2005/06 was expected to be £4.65/Btu. This represented a 113% increase in fuel prices, and had a significant impact on generation costs due to the high proportion of the total cost attributed to fuel. Figure 4 shows the revised generation costs with the higher fuel costs:

Gas CCGT:

Generation Costs:	Capital: £308/kW	Generation Costs:	
£/MWh		£/MWh	
Capital: £3.69	Annual Costs:	Capital: £3.69	Annual Costs:
O&M: £3.28	£/kW	O&M: £3.28	£/kW
Fuel: £33.45	Fixed: £54.34	Fuel: £33.45	Fixed: £54.34
Carbon: --	Variable: £260.80	Carbon: £2.28	Variable: £278.54
£40.42	£315.14	£42.70	£332.88

Figure 4: Cost analysis for a gas turbine, with natural gas priced at the levels expected for 2005/06.

By using the predicted gas prices for 2005/06, the CCGT moved from the cheapest to being easily the most expensive generation method available. The variable costs rose dramatically, giving nearly double the total cost of a nuclear reactor when operating for the entire year.

This helped to confirm the suggestion that gas turbines were now more suited as peaking plants, as their fixed costs are still much lower than for the other technologies described. Thus when operated for only a portion of the year, a CCGT would be more economical than either coal or nuclear. The implications this had for the grid and overall balance of plants is elaborated on in the following sections.

6.5. AP1000

Despite the maturity of the AP1000 design relative to other Generation III reactors, solid economic data was hard to attain. Commercially sensitive information such as this is not routinely provided as open literature, and so is not available to a general audience. Open cost estimates for the final generation price had been made by many sources, but the only detailed information was available directly from Westinghouse promotional literature. Two such documents consulted were the *AP1000 Summary Document* and *An Essential Programme to Underpin Government Policy on Nuclear Power*.

The final conclusion of an internal document entitled *British Energy and BNFL Collaboration on AP1000; Final Report* was provided,²⁶ however the values had to be taken as read as no further information on the assumptions and calculations involved could be made available. This report was considered with a higher relevance as it focussed

²⁶ The conclusion to this report was kindly provided by Andy Worrall of Nexia Solutions.

specifically on economic considerations for an AP1000 within the UK market, as opposed to generic or US-based assumptions that were expected from other sources.^[4]

The AP1000 design improves upon a standard reactor with a design lifetime of 60 years and 90% capacity factor.^[5] To provide the most cost effective solution - as favoured by China who will be the first to construct these plants - a pair of reactors consisting of two 1150MW units will be considered, giving a capacity of 18133GWh/year. Figure 5 shows the cost analysis for such a reactor.

AP1000:

Generation Costs:		
	£/MWh	Capital: £1140/kW
Capital:	£11.68	
Decom:	£0.57	Annual Costs:
O&M:	£5.57	£/kW
Fuel:	£3.36	Fixed: £140.47
Waste:	£0.67	Variable: £31.75
	<u>£21.84</u>	<u>£172.22</u>

Figure 5: Cost analysis for an AP1000 reactor.

The expected running costs of an AP1000 came out surprisingly similar to those of a Generation II reactor. The capital expenditure required was the same, and annual running costs were only 4% lower. This compares to the typical claims from promotional literature of a 10%-15% reduction in capital and running costs.^{[5][6]}

There was however a significant reduction in the generation price, which was 9% lower than for a Generation II reactor. This was mostly due to the higher capacity factor, which was 6% higher, thus allowing a 6% reduction in the effect of the fixed costs simply through more output per kW of capacity. This value given was considered acceptable, as claims for the AP1000 generation cost are typically in the range of £20-£25/MWh, with a UK specific estimate of £21.50/MWh²⁷.

The non-economic benefits of the AP1000 should not be overlooked, particularly the advances made in the approach to safety of the plant. It could be envisaged that after a sufficient demonstration of these improved controls, the highly cautious approach to building new reactors would be eased. The current process of applying to build a new reactor can take years until the first concrete is poured due to the perceived need for public enquiries and several reviews of the proposed safety case. If the underlying design of the AP1000 - or any Generation III reactor - was certified as fit for construction, then

²⁷ Generation cost estimates taken from sources 8, 9 and 11 listed in Appendix D. The UK specific estimate was taken from the summary of the British Energy & BNFL collaboration.^[5]

any proposed plants based on that design should be considered fit for construction. This would hopefully reduce the time required for gaining approval for a given site, and thus reduce the inherent lag in building new plants.

6.6. ACR-700

The ACR-700 was almost excluded from this report due to a lack of information about the reactor economics. Only one independent paper was consulted, which compared the costs of several electricity generation methods, including a standard CANDU reactor and the ACR-700. This paper was not a commissioned study into the proposed costs of the reactor, and it cited figures from the reactor’s manufacturers - AECL - on certain occasions.

However, it was considered worth the inclusion as more information was available on the ACR-700 than any of the other reactor designs otherwise considered. It would be considered wise to treat the numbers presented in Figure 6 with greater caution than for the other analyses made, as they were not all able to be cross-referenced against other sources.

Like the AP1000, the ACR-700 plant consisted of a pair of reactors giving a combined output of 1406MW. A lifetime of 60 years was used, with an expected capacity factor of 90%. It was noted that the ACR-700 reactor is expected to require a complete core overhaul after 30 years of operation. This would involve replacing the pressure tubes surrounding each fuel bundle, at an expected cost of £91m. This kind of significant maintenance was not an expected requirement of other reactor designs, as their design used a single vast pressure vessel that encompassed the entire core. It was expected this pressure vessel would last the entire lifetime of the reactor, or would possibly be one of the components that determined the maximum operating life. The core replacement costs for the ACR-700 were included in the decommissioning costs shown in Figure 6 below.

ACR-700:

Generation Costs:		
	£/MWh	Capital: £1070/kW
Capital:	£10.99	
Decom:	£0.88	
O&M:	£4.96	
Fuel:	£1.83	
Waste:	£0.61	
	<u>£19.26</u>	
		Annual Costs:
		£/kW
		Fixed: £132.61
		Variable: <u>£19.24</u>
		<u>£151.85</u>

Figure 6: Cost analysis for an APR-700 reactor.

Both the cost of generation and the annual costs of the ACR-700 were the lowest of any plant under consideration. The generation cost was 20% lower than for a Generation II reactor, and 12% lower than from the AP1000. Unlike the AP1000, there was also a substantial reduction in the annual costs of an ACR-700 compared to a Generation II reactor, so the reduction in generation price was not primarily due to the increased availability of the plant.

One area of saving was the 6% reduction in capital costs compared to either of the other nuclear reactors. Although this is only a modest saving, the difference separating plants is small enough for it to have a notable effect on the fixed costs of the reactor. The other major reduction in costs came from the front-end fuel costs, which were around half those of the other reactors. Although this was a significant reduction in a specific cost, the effect on the overall generation price was of similar size to the 6% reduction in capital costs.

The reduction in fuel costs was expected, although not to such an extent. The ACR-700 builds on the strong qualities of the CANDU reactors, which is the most uranium efficient design available. The heavy water moderator gives a better neutron economy than other designs using graphite or light water, and so either lower enrichment or higher burnup times can be achieved. The ACR-700 is expected to use a compromise of 1.5-2.0% enriched uranium, which would extend the fuel lifetime to three times that of existing CANDU reactors.^[7]

With variable costs of just £2.44/MWh, the ACR-700 would be the cheapest reactor to operate for base load capacity, being able to cover its costs for 40% less than an AP1000. Although this analysis cannot be given the same weight as for others made in this report, it is suggested that the ACR-700 has strong potential for profit in the UK market.

6.7. FINANCIAL APPRAISAL OF REACTORS

With an average annual electricity price of £50/MWh, it would appear that the economics of any type of nuclear reactor would be very favourable. The expected annual returns are given in Figures 7 and 8, with a summary of the financial indicators described in Chapter 2.4.

	Generation II (1000MWe)	AP1000 (2300MWe)	ACR-700 (1406MWe)	
Capital:	£1,140	£2,622	£1,603	(£m)
Costs:	£179.7	£396.1	£213.5	
Revenue:	£372.3	£906.7	£554.2	
Returns:	£192.6	£510.5	£340.7	
ARR:	16.90%	19.47%	21.26%	(years)
Payback:	5.9	5.1	4.7	
IRR:	20.32%	24.18%	27.00%	

Figure 7: Financial summary for the three nuclear reactors, calculated with an average electricity spot price of £50/MWh.

All of these reactors would perform well within a market where spot prices averaged £50/MWh. The capital required, and the annual return from each plant is notably different, due to the different scales that were considered. For example, the AP1000 would require exactly 2.3 times the capital of the Generation II plant, but would give 2.7 times the annual return. The financial indicators given in the lower portion of the table are unconcerned with the scale of a particular plant, as they measure the returns relative to the investment required.

The annual rate of return for each plant is simply the reciprocal of the payback period. The maximum payback period was less than 6 years, and was for the Generation II reactor as it had the highest generation costs. This would imply that the initial debts and equity used to fund the reactor could be repaid within 6 years, if the returns were used solely to repay these debts. The initial cost analysis assumed however that capital would be repaid over the lifetime of the reactor, so this is a somewhat misleading impression to give, as the returns from the reactor would be put to other uses within the parent company. Given the expected economic lifetime of this reactor was 40 years this is considered a low payback period, as it is less than one sixth of the working lifetime. For the AP1000 and ACR-700 reactors the payback period is shorter, for reactors that would have an even longer working lifetime. The reduction in capital investments and increased returns on the sale of electricity mean these reactors could cover their initial debts within about 5 years.

The more useful figure of merit is the internal rate of return. A general rule for evaluating projects is that the IRR should remain higher than the cost of the capital, or the desired rate of return on equity.^[8] For this analysis, a discount factor of 8% was applied to the capital investment, so an IRR of 10% would be sufficiently above this to appeal to potential investors. The lowest IRR was again for the Generation II reactor, but was over double this recommended value. So long as the cost of debts was less than 20% per annum, the reactor would be expected to make a profit. Again, the situation was even better for the

Generation III reactors, with IRRs of 24% and 27% respectively. It could be concluded that in that particular market, these reactors would be very unlikely to lose money.

Therein lies the caveat of this analysis - there is no way to guarantee that the electricity market will remain at the prices expected for 2005/06. Even though the prediction ranging up to 2010 gave consistent prices around £50/MWh, it was not to be taken as more than a rough guide. To assume that prices would remain at that level or higher until 2050 and beyond would be unwise, at best. Without a means of reliably predicting the market over such a long term, the best recourse was to analyse the profitability of each reactor given different market conditions. If the change in performance with average electricity prices was known, a better judgement could be made on whether a reactor was likely to succeed.

Figure 8 shows the same indicators given in Figure 7, calculated with an average spot price of £25/MWh, which was still above the levels seen in 2001/04.

	Generation II (1000MWe)	AP1000 (2300MWe)	ACR-700 (1406MWe)	
Capital:	£1,140	£2,622	£1,603	(£m)
Costs:	£179.7	£396.1	£213.5	
Revenue:	£186.2	£453.3	£277.1	
Returns:	£6.5	£57.2	£63.6	
ARR:	0.57%	2.18%	3.97%	(years)
Payback:	176.0	45.8	25.2	
IRR:	-	0.97%	3.63%	

Figure 8: Financial summary for the three nuclear reactors, calculated with an average electricity spot price of £25/MWh.

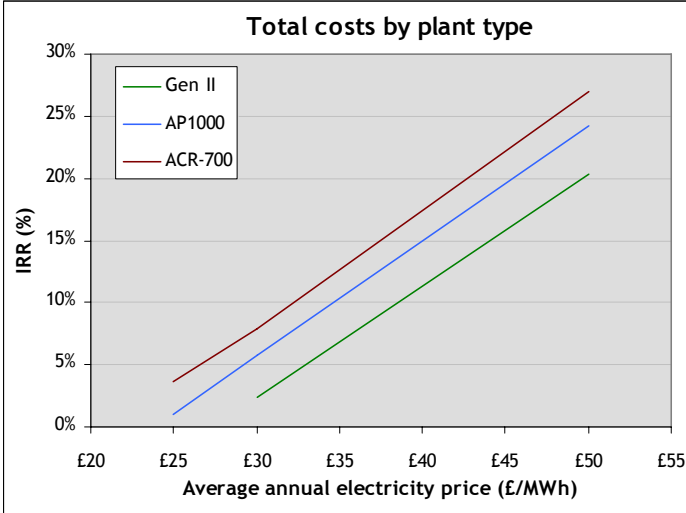
The performance of the reactors is very different with the lower electricity price. Most notably, the Generation II reactor barely breaks even - recouping less than 1% of its capital each year.

Only the Generation III reactors would be able to reclaim their capital within their operational lifetimes, and even then it would take decades to recover. The difference between the AP1000 and ACR-700 became more apparent, as the £2.60/MWh difference in their generation prices became more significant.

The IRR of each reactor highlights the difference in this situation. Most notably, the Generation II reactor does not have a value for the IRR, there was no discount rate that

would allow it to recover its capital²⁸. The other reactors did not perform much better, with IRRs much lower than the 10% guideline value.

One final way of comparing the reactors was to find the spot price that would give an IRR of 10%. A decision maker could find this a useful measure, as it would be easier to assess how likely electricity prices are to remain above a certain price than to predict an absolute price they will remain at. A plot of IRR against spot price is shown in Figure 9.



	Generation II	AP1000	ACR-700
Annual spot price to give 10% IRR:	£38.09	£35.03	£32.45

Figure 9: The variation in IRR for the three nuclear reactors with average spot price.

The IRR of the three reactors varies linearly with the annual spot price, rising approximately 1% for every £1/MWh increase. The difference between reactors can clearly be seen by the annual prices required to exceed an IRR of 10%. The Generation II performs worst, requiring 17% higher prices in order to give the same performance as an ACR-700. The AP1000 is a mid-way performer, requiring £3.06/MWh less than the Generation II, but £2.58/MWh more than the ACR-700. These differences are larger than the difference in generation costs due to other factors, such as the shorter lifetime of the Generation II reactor, and the lower capital outlay for the ACR-700.

The real question facing decision makers is how confident they are that electricity prices will remain above £32, £35 or £38/MWh over the coming decades. This question would be difficult if not impossible to give a reliable answer for, as the level of uncertainty would be overwhelming. This is the fundamental limitation of financial appraisal, it will not tell you whether a project will be successful or not, only whether it is better than another

²⁸ An IRR of -3% was calculated. The idea of banks paying an energy company to borrow billions of pounds from them was considered to be outside the realms of possibility.

project or not. The solid conclusion that can be drawn from this appraisal is that the ACR-700 is the most likely to return a profit, and the Generation II reactor is the least likely. This conclusion is however based on the assumption that the economic analysis of the ACR-700 was sound, and the single source consulted was representative of the reactors true costs. A safer choice would be the AP1000, as it is clearly superior to a Generation II reactor, and the analysis is considered to be more solid.

6.8. MARKET CONSIDERATIONS

With the fixed and variable costs of the different plants known, the analysis presented in Chapter 4.3. could be made. Initially, the total costs for each plant type were plotted against the duration of usage. This would give insight into the optimal role for each plant type, and would help plant owners decide what level of each type of capacity was required. The costs of the Generation II, CCGT and Coal PF plant are shown in Figure 10.

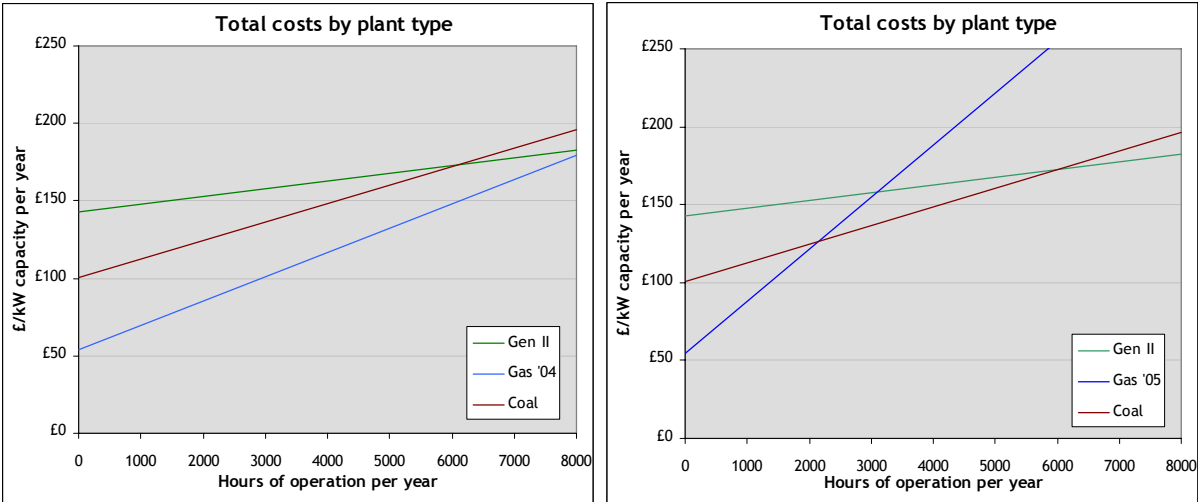


Figure 10: The cost of operating each conventional plant for a variable portion of the year, with the price of natural gas from 2004 (left) and the predicted price for 2005 (right).

The left hand plot in Figure 10 demonstrated that with the fuel prices set within the National Academy report, the CCGT was ideally suited to both peaking and base load operation. Its total cost was the lowest of any existing plant under consideration, for any operating period. When the price of gas was raised to the prediction for 2005/06, the variable costs of the CCGT soared, as shown on the right hand plot of Figure 10. Despite the high gradient of the CCGT costs, it is still the cheapest option for a peaking plant due to the substantially lower fixed costs.

Two transition points are seen in this graph at around 2150 hours and 6050 hours, where coal becomes cheaper than gas (T_1), and then nuclear becomes cheaper than coal (T_2). These transition points would aid plant operators to decide what mix of generation technologies would be most profitable when combined with a load-duration curve for the electricity market, so that the amount of capacity that is required at T_1 and T_2 hours would be known.

With gas prices at 2005 levels, the Generation II nuclear reactor would appear to be an economical option for base load generation. Its total costs are up to 25% lower than those of a coal plant when operated for the full year, and so long as the plant is running at >50% load it should be the cheapest of the three options.

The three nuclear reactors are compared against each other in Figure 11. The similarity between the Generation II and AP1000 costs is more evident from their cost lines - which are notably higher than the ACR-700. Although the fixed costs are similar for all three reactors, the lower variable costs allow the ACR-700 to become £20/kW cheaper than even the AP1000 when operated over the entire year.

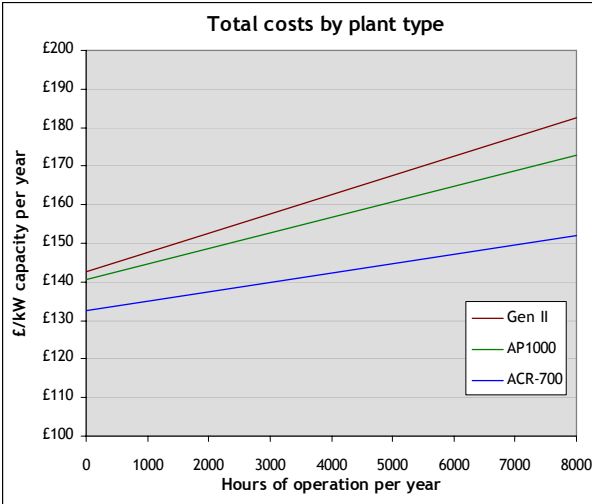


Figure 11: The total operating costs of each nuclear reactor.

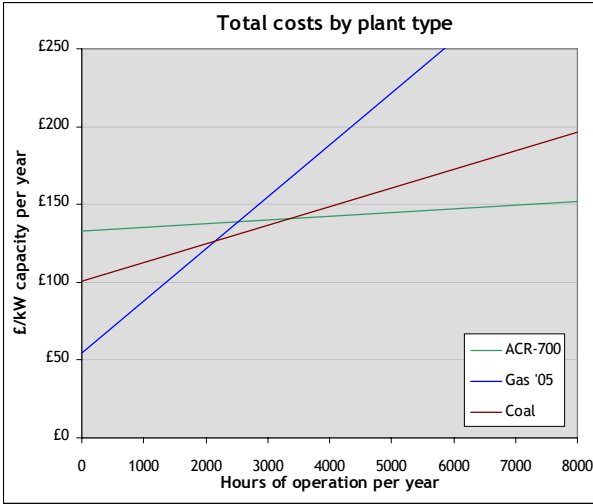


Figure 12: The costs of running an ACR-700 compared to other generation forms

The ACR-700 is compared against the coal and gas plants in Figure 12 above.

The change shown between Figure 10 and 12 is significant, with the lower variable costs of the ACR-700 improving its standing against a coal plant. The second transition point T_2 moved from 6050 hours to 3400 hours, which would signal to market operators that coal plants should be retired and more nuclear reactors built to replace their capacity. Nuclear plants would become the cheapest option when run for anything over 40% of the year, compared to 70% of the year for Generation II plants.

If the ACR-700 was capable of operating at the cost given in this report, it would make economic sense to build a large fleet of these reactors, replacing much of the existing fossil fuel plants and thus reducing the country's emissions of CO₂. The introduction of a tax on the absolute amount of carbon emissions from fossil fuel plants would have a similar effect, making any nuclear reactor a more attractive alternative than it is today.

8. APPENDICES

8.1. ESTIMATING REACTOR COSTS

This appendix gives a list of the supporting evidence used to produce the cost estimates given in Chapter 6.1. The individual sources are referred to by number for clarity, for example: [1] refers to the source given by reference 1.

The following assumptions were made in all cases where possible:

- All monies were converted to a value in 2005 sterling where the date of a value was known, using an annual inflation of 2.5%.
- Exchange rates of £1 = US\$1.80, and £1 = C\$2.30 was used²⁹.

8.2. STANDARD GENERATION II REACTOR

Capital & Decommissioning:

- [1] proposed £1179/kW capital costs, which included an allowance for decommissioning.
- [2] proposed \$2101/kW (£1167/kW), presumably for an American PWR, and was one of the sources consulted by [1].
- [1] translated its cost into £13.53/MWh. Splitting this roughly into capital and decommissioning costs gave £12.85/MWh and £0.68/MWh respectively.
- Assuming 7446GWh of output per year, the annual costs for these would be £95.71/kW and £5.04/kW respectively.
- Applying a discount factor of 8% on these capital payments gave a present value of the construction alone as £1141/kW.

O&M:

- [1] gave £42/kW per year for O&M, or £4.61/MWh. These figures alone were contradictory as they gave 9111GWh/year operating time (379 days per year).
- [1] also allocated £0.82/MWh to general overhead, which can be reasonably assumed to be contained in the £42/kW annual figure. £42/kW and £5.43/MWh correspond to 7736GWh/year, or an 88% uptime, which was deemed acceptable.
- [2] gave the past operating costs of American nuclear reactors as around \$19/MWh with fuel included. They concluded this should be reduced to \$15/MWh (£8.76/MWh) as operators in a competitive wholesale market would want to “demonstrate better than average performance to investors”.^[2] Taking fuel cost into account, this gave £4.66/MWh for O&M, which excluded “administrative and other costs”. [2] predicted these would increase the cost by ~20%, giving £5.59/MWh.

²⁹ The approximate values for the Interbank average rate over the past 2 years.

- The figures for total O&M from [1] were accepted, with the cost per MWh adjusted to use an 85% uptime, giving £42.00/kW annually and £5.64/MWh.

Fuel:

- [1] gave the fuel cost as £4.10/MWh, stating that [2] proposed a range of £3.15-£4.20/MWh which was “slightly lower than data sources [they] had reviewed”^[1]. It was unclear whether the cost of spent fuel management was included in the price given in [1], the only indication being the omission of disposal costs elsewhere in their analysis.
- [3] gave \$3.50/MWh (£1.94/MWh) as the cost of fuel fabrication. This was based on 1kg of 3.5% enriched uranium producing 315MWh³⁰. 7.8kg of natural uranium and 4.3SWU (seperative work units) would be required to produce 1kg of enriched fuel. The costs were given as \$40/kg of mined uranium, \$10/kg for conversion to UF₆ and \$110/SWU, plus about \$240/kg for fabrication - giving \$1103/kg.
- The prices for each step labelled in [3] were from October 2004 at the latest. [4] gave spot prices in July 2005 of \$65/kg of U₃O₈, \$12/kg for conversion, and \$113/SWU. Using these figures, 1kg of 3.5% enriched fuel would cost \$600 + \$486 + \$240 = \$1326, or \$4.21/MWh (£2.33/MWh)
- Within the sensitivity analysis of [16], the entire fuel cycle costs were given with a discount factor of 8%. Adjusting for 10 years of inflation this gave the cost of acquiring fuel as £3.70/MWh.
- A front-end fuel cost of £3.70/MWh was accepted as being within the range of findings in [1] and [2].

Waste:

- [6] claimed in 2001 British Energy were paying £4.97/MWh for waste disposal, about 6 times the price paid in the US³¹. In 2003 BE renegotiated their contract with BNFL, although the new price being paid is not openly known.
- [9] gave the cost of spent fuel reprocessing as £0.67/MWh for an AP1000 reactor. (see later)
- The waste levels of an AP1000 were compared against a Magnox design in [9] and [10] to highlight the advances made by the AP1000, although this was not a useful comparison as Magnox reactors are from Generation I and can barely be described as modern or economical.
- [7] showed that per GWh generated, approximately half the amount of fuel is discharged from an AP1000 than from an AGR (and less than 1/10th the amount from a Magnox). It would follow that reprocessing costs would be around twice as expensive for an AGR reactor, assuming the structure and processing required by each fuel is similar.
- This gave a rough estimate of reprocessing costs as being £1.34/MWh.
- [16] gave a value for the back-end fuel costs, which included transport, reprocessing and disposal. When adjusted, the total cost was £1.26/MWh, with a credit of £0.14/MWh given for the recovered uranium and plutonium.
- £1.26/MWh was accepted, as it agrees well with the inferred estimate from [7] and [9].

³⁰ Based upon 33% thermal efficiency and ‘modern’ burn-up rates.

³¹ It should be noted that the US figure relates to disposal rather than reprocessing, which is ~20% cheaper.^[16]

8.3. COAL AND GAS PLANTS

All the values provided by [1] were used as the only source for these plants, with 1 year of inflation added to every value for consistency. When re-analysing the gas turbine to use 2005/06 predicted prices, the value given for carbon emissions was multiplied by 0.6. Coal prices were not re-evaluated as the price of coal is expected to remain consistent, with a slight downwards trend in the near future.^[8]

8.4. AP1000

Capital:

- [9] claimed the capital cost for the first of kind to be built would be £19.60/MWh, reducing to £11.95/MWh for the 4th in the series. The (n)th reactor cost was used, as this gave a better representation for the cost of a large fleet, and would be the cost quoted for Generation II reactors.
 - This value was presumed to be for a single reactor; if twin reactors were built the second would have 80% of the construction cost of the first^[9] - giving an average of £10.76/MWh for two reactors. It was not stated what lifetime these values correspond to, so 60 years was assumed.
- [10] gave a total capital cost £16.41/MWh, assuming a 40 year lifetime and 8% interest rate. This gave an initial capital expenditure of £1542/kW. Again presuming this was for a single reactor, the 20% discount on a second reactor would give a £1388/kW average. Increasing the repayment period to 60 years would require £112/kW annually, or £14.23/MWh.
 - Numbers banded about in [7] stated that in comparison to a Generation II reactor, 10% lower capital cost would give a 6% reduction in generation price. It is suggested that [10] perhaps used the first of kind construction costs, as they turned out to be higher than for a Generation II reactor. For this reason, this value was discarded.
- [11] gave the contribution to the generation cost as £3.57/MWh from capital with £9.04/MWh for financing the debts, giving a total of £12.61/MWh.
 - This cost includes “UK specifics such as first of a kind (FOAK) costs such as licensing”.^[12] These additional costs were not elaborated upon, but it can be assumed they would become trivial if a substantial number of AP1000's were to be built, as is hypothesised within this report.
- The values from [9] and [11] were accepted, with the value from [11] considered to be on the high side as FOAK costs had been factored in. The average of these two values was therefore taken, giving £11.68/MWh.
- This average would translate to £92.11/kW annually, which if paid over a 60 year lifetime would give an initial cost of £1140/kW.

Decommissioning:

- [9] gave £0.65/MWh, [10] gave £0.57/MWh, [11] gave £0.53/MWh.
 - It was noted the only difference between the figures given in their native currency and time was that [9] gave £0.60/MWh, whereas [10] and [11] both gave £0.50/MWh.

- The weighted average³² cost of £0.57/MWh was accepted.

O&M:

- [9] gave £7.43/MWh as O&M costs, which included the “ultimate disposal of low and intermediate level wastes”.
- [10] gave £7.07/MWh as O&M costs, while [11] gave £5.57/MWh.
- According to [11], the disposal of waste should contribute very little to the running costs of a reactor given suitable forward planning for it. As disposal occurs after many decades, the discount factor will greatly reduce the eventual cost in today’s terms. With the 8% discount factor scenario, <1p/MWh was allocated disposal of waste.
- [13] stated that for a twin AP600 plant, O&M costs should be 35% lower than the industry average. Although this was promotional material directly from Westinghouse, the value gave an indication of what Westinghouse expected the O&M costs for an AP600 should be.
- [2] gave the US industry average O&M cost as £8.40/MWh³³. This would give the expected O&M costs as £5.46/MWh if the same reduction were true for the AP1000, which should be a valid assumption as it is fundamentally similar to the AP600, and expected similar costs per unit capacity.
- Based on this additional reasoning, the value from [11] was accepted without input from [9] or [10].

Fuel:

- [9] gave the front-end fuel cost as £3.23/MWh, with [10] gave £3.68/MWh and [11] gave £3.26/MWh.
- The weighted average was taken, giving £3.36/MWh.

Waste:

- [9] gave the back-end costs as £0.86/MWh, [10] gave £0.57/MWh and [11] gave £0.63/MWh.
- Again, the weighted average was taken, giving £0.67/MWh.

8.4. ACR-700

Capital:

- [14] gave the capital construction cost as C\$3.5bn, or C\$2466/kW (£1072/kW). In a publicly financed venture, it suggested this would amount to a cost of C\$36.33/MWh (£15.80/MWh).
- This value corresponded to a discount rate of 10%³⁴ and a repayment period of 20 years. For consistency with other reactors, the payments were altered to be over 60 years with an 8% discount rate. The capital repayment was calculated as £86.82/kW annually, contributing £10.99/MWh.

³² The average was weighted in favour of [11] when no other deciding factor between values was present, as it was known to relate specifically to UK considerations.

³³ This was based on the value of \$19/MWh that was achieved, rather than the \$15/MWh that should ideally be attained.

³⁴ 8% interest rate on debts, and 12% real rate of return on equity was used, with a 50/50 split of capital coming from debt and equity.

Decommissioning:

- [14] gave expected annual decommissioning costs for three economic lifetimes as £5.0m over 20 years, £3.7m over 30 years and £2.3m over 40 years. It is considered that these were been made with no discount rate applied as they would amount to a total present value of £100m, £110m and £91m respectively, showing no sign of upward or downward trend with repayment period.
- To remain consistent with other reactor analyses, the decommissioning payments were spread over the entire 60 year lifetime of the reactor with a discount rate of 4%. To achieve the average initial-value capital suggested by [14], payments of £4.4m/yr were required, which equated to £3.16/kW annually, or £0.40/MWh.
- There was no justification given in [14] for the 30% reduction in decommissioning cost with respect to either a PWR or AP1000 design, so the combination of values given and their interpretation was deemed invalid.
- The cost of decommissioning was therefore set at £0.57/MWh, inferred from the AP1000 analysis.
- [14] suggested that after 30 years, the pressure tubes in an ACR would be expected to need a complete replacement, at a cost of £91m. This kind of core overhaul was not mentioned in other reactor designs, and was not expected to be a requirement for them. The ACR and CANDU designs employ smaller and thinner pressure tubes, as opposed to a vast pressure vessel that would either be designed to last the lifetime of the reactor, or possibly determine it.
- As this money would not be required up-front, annual payments would be devalued by 4% as with decommissioning, and so an allowance of £5.3m annually would be required to meet this cost after 30 years, equating to £0.48/MWh.
- These figures gave a total cost for decommissioning and overhaul as £0.88/MWh.

O&M:

- [14] gave O&M costs of £4.96/MWh, which it claimed corresponded to £49m per year. These two values suggested a capacity factor of only 81%³⁵, compared to the 93%³⁶ expected capacity factor.
- [15] suggested “O&M and Fuel costs of < \$10/MWh”, although it should be noted this presentation also suggested “< \$1000/kW” construction costs, and so proved itself irrelevant.
- It was not clear which value from [14] best represented an estimate for the O&M costs with a 90% capacity factor, as neither value came with an explanation. The higher cost option of accepting £4.96/MWh was taken, giving an annual cost of £55m.

Fuel:

- [14] gave fuel costs of £1.83/MWh for fuel acquisition, enrichment and fabrication, sourced from AECL.
 - This fuel cost was notably lower than for a Generation II or AP1000 reactor. This was not discounted however, as the result was somewhat expected given the nature of the CANDU and ACR designs.
 - For reference, [14] gave the fuel cost of a CANDU reactor - which does not require enrichment - as just £1.05/MWh.

³⁵ $1406\text{MW} \cdot 8760 \text{ h/yr} \cdot 81\% = 9976\text{GWh/yr}$, $\text{£}4.96/\text{MWh} \cdot 9976\text{GWh/yr} = \text{£}49.5\text{m / yr}$.

³⁶ Prediction given by [15], based on an 87% lifetime capacity from all existing CANDU-6 reactors, with 97% achieved in one year by the top 3 performers.^[15]

Waste:

- [14] cites an estimate from a 2001 US DOE report of £0.61/MWh for disposal of spent fuel.
 - The difference between the fuel cycles typically operated in the US and UK does not appear to have greatly influenced the cost attributed to disposal (c.f. £0.67/MWh for an AP100), so this value was considered acceptable.

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