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The Future of Nuclear Power

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Chapter 5 — Nuclear Power Economics

Investments in commercial nuclear generating facilities will only be forthcoming if investors expect the cost of producing electricity using nuclear power will be lower than the risk-adjusted costs associated with alternative electric generation technologies. Since nuclear power plants have relatively high capital costs and very low marginal operating costs, nuclear energy will compete with alternative electricity generation sources for "baseload" (high load factor) operation. We recognize that over the next 50 years some significant but uncertain fraction of incremental electricity supplies will come from renewable energy sources (e.g. wind) either because these sources are less costly than alternatives or because government policies (e.g. production tax credits, high mandated purchase prices, and renewable energy portfolio standards) or consumer choice favor renewable energy investments. Despite the efforts to promote renewable energy options, however, it is likely that a large fraction of the incremental and replacement investments in electric generating capacity needed to balance supply and demand over the next 50 years will, in the absence of a nuclear generation option, rely on fossil-fuels — primarily natural gas or coal. This is particularly likely in developing countries experiencing rapid growth in income and electricity consumption. Accordingly, we focus on the costs of nuclear power compared to these fossil fuel generating alternatives in base-load applications.

Any analysis of the costs of nuclear power must take into account a number of important considerations. First, all of the nuclear power plants operating today were developed by state-owned or regulated investor-owned vertically-integrated utility monopolies.[1] Many developed countries and an increasing number of developing countries are in the process of moving away from an electric industry structure built upon vertically integrated regulated monopolies to an industry structure that relies primarily on competitive generation power plant investors. We assume that in the future nuclear power will have to compete with alternative generating technologies in competitive wholesale markets — as merchant plants.[2] These changes in the structure of the electric power sector have important implications for investment in generating capacity. Under traditional industry and regulatory arrangements, many of the risks associated with construction costs, operating performance, fuel price changes, and other factors were borne by consumers rather than suppliers.[3] The insulation of investors from many of these risks necessarily had significant effects on the cost of capital they used to evaluate alternative generation options and on whether and how they took extreme contingencies into account. Specifically, the process reduced the cost of capital and led investors to give less weight to regulatory (e.g. construction and operating licenses) and construction cost uncertainty, operating performance uncertainties and uncertainties associated with future oil, gas and coal prices than if they had to bear these cost and performance risks.

In a competitive generation market it is investors rather than consumers who must bear the risk of uncertainties associated with obtaining construction and operating permits, construction costs and operating performance. While some of the risks associated with uncertainties about the future market value of elec-

tricity can be shifted to electricity marketers and consumers through forward contracts, some market risk and all construction cost, operating cost and performance risks will continue to be held by power plant investors.[4] Thus, the shift to a competitive electricity market regime necessarily leads investors to favor less capital-intensive and shorter construction lead-time investments, other things equal.[5] It may also lead investors to favor investments that have a natural "hedge" against market price volatility, other things equal.[6]

Second, the construction costs of nuclear plants completed during the 1980s and early 1990s in the United States and in most of Europe were very high — and much higher than predicted today by the few utilities now building nuclear plants and by the nuclear industry generally. The reasons for the poor historical construction cost experience are not well understood and have not been studied carefully. The realized historical construction costs reflected a combination of regulatory delays, redesign requirements, construction management and quality control problems. Moreover, construction on few new nuclear power plants has been started and completed anywhere in the world in the last decade. The information available about the true costs of building nuclear plants in recent years is also limited. Accordingly, the future construction costs of building a large fleet of nuclear power plants is necessarily uncertain, though the specter of high construction costs has been a major factor leading to very little credible commercial interest in investments in new nuclear plants. Finally, while average U.S. nuclear plant availability has increased steadily during the 1990s to a high of 90% in 2001, many nuclear plants struggled with low availabilities for many years and the life-cycle availability of the fleet of nuclear plants (especially taking account of plants that were closed early) is much less than 90%.[7] In addition, the average operation and maintenance costs of U.S. nuclear plants (including fuel) were over $20/MWh during the 1990s (though average O&M costs had fallen to about $18/MWe-hr and the lowest cost quartile of plants to about $13/MWe-hr by 2001)[8], rather than the $10/MWe-hr often assumed in many paper engineering cost studies.

Third, even if an investment in nuclear power looked attractive on a spreadsheet, investors must confront the regulatory and political challenges associated with obtaining a license to build and operate a plant on a specific site. In the past, disputes about licensing, local opposition, cooling water source and discharge requirements, etc., have delayed construction and completion of nuclear plants. Many planned plants, some of which had incurred considerable development costs, were cancelled. Delays and "dry-hole" costs are especially burdensome for investors in a competitive electricity market.

With these considerations in mind, we now proceed to examine the relative costs of new nuclear power plants, pulverized coal plants, and combined-cycle gas turbine (CCGT) plants in base-load operations in the United States.[9] The analysis is not designed to produce precise estimates, but rather a "reasonable" range of estimates under a number of different assumptions reflecting uncertainties about future construction and operating costs. Similar analysis for Europe and especially Japan and Korea would be somewhat more favorable to nuclear, since gas and coal costs are typically higher than in the United States.

We start with a "base case" that examines the levelized *real* life-cycle costs of nuclear, coal, and CCGT generating technology using assumptions that we believe commercial investors would be expected to use today to evaluate the costs of the alternative generation options. The levelized cost is the constant real wholesale price of electricity that meets a private investor's financing cost, debt repayment, income tax, and associated cash flow constraints.

The base case assumes that non-fuel O&M costs can be reduced by about 25% compared to the recent operating cost experience of the average

nuclear plant operating in the U.S. in the last few years. This puts the total O&M costs (including fuel) at about 15 mills/kWe-hr. We include this reduction in O&M costs in the base case because we expect that operators of new nuclear plants in a competitive wholesale electricity market environment will have to demonstrate better than average performance to investors. The 15 mill O&M cost value is consistent with the performance of existing plants that fall in the second lowest cost quartile of operating nuclear plants.[10] (The assumptions underlying the base case are listed in Table 5.3 and illustrative cash flows produced by our financial model are provided in Appendix 5.)

We then examine how the real levelized cost of nuclear generated electricity changes as we allow for *additional* cost improvements. First, we assume that construction costs can be reduced by 25% from the base case levels to more closely match optimistic but plausible forecasts. Second, we examine how life-cycle costs are further reduced by a one-year reduction in construction time. Third, we examine the effects of reducing financing costs to a level comparable to what we assume for gas and coal generating units as a consequence of, for example, reducing regulatory risks and commercial risks associated with uncertainties about construction and operating costs that presently burden nuclear compared to fossil-fueled alternatives. This reduction in financial risk might result from an effective commercial demonstration program of the type that we discuss further in Part II. Finally, we examine how the relative costs of coal and CCGT generation are affected by placing a "price" on carbon emissions, through carbon taxes, the introduction of a carbon emissions cap and trade program, or equivalent mechanism to price carbon emissions to internalize their social costs into investment decisions in a way that treats all supply options on an equivalent basis. We consider carbon prices in a range that brackets current estimates of the costs of carbon sequestration (capture, transport and storage). The latter analysis provides a framework for assessing the option value of nuclear power if and when the United States adopts a program to stabilize and then reduce carbon emissions.

The levelized cost of electric generating plants has typically been calculated under the assumption that their regulated utility owners recover their costs using traditional regulated utility cost of service cost recovery rules. Investments were recovered over a 40 year period and debt and equity were repaid in equal proportions over this lengthy period at the utility's cost of capital, which reflected the risk reducing effects of regulation. Moreover, the calculations typically provided levelized *nominal* cost values rather than levelized *real* cost values, obscuring the effects of inflation and making capital intensive technologies look more costly relative to alternatives than they really were.

We do not believe that these traditional levelized cost models based on regulated utility cost recovery principles provide a good description of how merchant plants will be financed in the future by private investors. Accordingly, we have developed and utilized an alternative model that provides flexibility to specify more realistic debt repayment obligations and associated cash flow constraints, as well as the costs of debt and equity and income tax obligations that a private firm would assign to individual projects with specific risk attributes, while accounting for corporate income taxes, tax depreciation and the tax shield on interest payments. We refer to this as the Merchant Cash Flow model. We have relied primarily on simulation results using this model under assumptions of both a 25-year and 40-year capital recovery period and 85% and 75% lifetime capacity factors.

BASE CASE

The base case reflects reasonable estimates of the current perceived costs of building and operating the three generating alternatives in 2002 U.S. dollars. The overnight capital cost for nuclear in the base case is $2000/kWe. As discussed in Appendix 5, this value is consistent with estimates made by the U.S. Energy

Information Administration (EIA), estimates reported by other countries to the OECD, and recent nuclear plant construction experience abroad. We have not relied on construction cost data for U.S. plants completed in the late 1980s and early 1990s; if we had, the average overnight construction cost in 2002 U.S. dollars would have been much higher. We are aware that some vendors and some potential investors in new nuclear plants believe that they can achieve much lower construction costs. We consider significant construction cost reductions in our discussion of improvements in nuclear costs.[11]

As previously discussed, our base case assumes that O&M costs are 15 mills/kWe-hr, which is lower than the recent experience for the average nuclear plant and is consistent with the recent performance of plants in the second lowest cost quartile of operating nuclear plants in the U.S. The O&M costs of plants in the lowest cost quartile (best performers) are about 13 mills/kWe-hr. We consider this to represent the potential for further cost improvements for a fleet of new nuclear plants but we do not believe that investors will assume that all plants will achieve the O&M cost levels of the best performers.

The construction costs assumed for CCGT and coal plants are in line with experience and EIA estimates. The construction cost of the coal plant is assumed to reflect NOx and SO_2 controls as required to meet current New Source Performance Standards. There are four cases presented for the CCGT plants: (1) a low gas price case that starts with gas prices at $3.50/MMBtu which rise at a real rate of 0.5% over 40 years (real levelized cost of $3.77/MMbtu over 40 years); (2) a moderate gas price case with gas prices starting at $3.50/MMBtu as well, but rising at a real rate of 1.5% per year over 40 years (real levelized cost of $4.42 over 40 years); (3) high gas price case that starts at $4.50/MMbtu and rises at a real rate of 2.5% per year (real levelized cost of $6.72/Mmbtu over 40 years). (4) The fourth CCGT case reflects high gas prices and an advanced CCGT design with a (roughly) 10% improvement in its heat rate. The base case results for 25 and 40-year economic lives and 85% capacity factor are reported in Table 5.1 and the equivalent results for a 75% lifetime capacity factor are reported in Table 5.2. The assumptions for the cases are given in Table 5.3. The discussion that follows is based on the 85% capacity factor simulations since the basic results don't change very much when we assume the lower capacity factor.

The base case results suggest that nuclear power is much more costly than the coal and gas alternatives even in the high gas price cases. In the low gas price case, CCGT is cheaper than coal. In the moderate gas price case, total life-cycle coal and gas costs are quite close together, though we should recognize that there are regions of the country with below average coal costs where coal would be less costly than gas and vice versa. Under the high gas price assumption, coal beats gas by a significant amount. (We have not tried to account for the relative difficulties of siting coal and gas plants.) We discuss potential future carbon emissions regulations separately below.

This suggests that high natural gas prices will eventually lead investors to switch to coal rather than to nuclear under the base case assumptions as nuclear appears to be so much more costly than coal and U.S. coal supplies are very elastic in the long run so that significant increases in coal demand will not lead to significant increases in long term coal prices. In countries with less favorable access to coal, the gap would be smaller, but 2.5 cents/kWe-hr is too large a gap for nuclear to beat coal in many areas of the world under the base case assumptions (absent additional restrictions on emissions of carbon dioxide from coal plants which we examine separately below).

The bottom line is that with current expectations about nuclear power plant construction costs, operating cost and regulatory uncertainties, it is extremely unlikely that nuclear power will be the technology of choice for merchant plant investors in regions where suppliers have

access to natural gas or coal resources. It is just too expensive. In countries that rely on state owned enterprises that are willing and able to shift cost risks to consumers to reduce the cost of capital, or to subsidize financing costs directly, and which face high gas and coal costs, it is possible that nuclear power could be perceived to be an economical choice.[12]

IMPROVEMENTS IN NUCLEAR COSTS

We next examine how the cost of electricity generated by nuclear power plants would change, if effective actions can be taken to reduce nuclear electric generation costs in several different ways. First, we assume that construction costs can be reduced by 25%. This brings the construction costs of a nuclear plant to a level more in line with what the nuclear industry believes is feasible in the medium term under the right conditions.[13] While this reduces the levelized cost of nuclear electricity considerably, it is still not competitive with gas or coal for any of the base cases. Reducing construction time from 5 years to 4 years reduces the levelized cost further, but not to a level that would make it competitive with fossil fuels. However, if regulatory, construction and operating cost uncertainties could be resolved, and the nuclear plant could be financed under the same terms and conditions (cost of capital) as a coal or gas plant, then the costs of nuclear power become very competitive with the costs of CCGTs in a high gas price world and only slightly more costly than pulverized coal plants, assuming that comparable improvements in the costs of building coal plants are not also achieved. If nuclear plant operators could reduce O&M costs by another 2 mills to 13 mills/kWe-hr, consistent with the best performers in the industry, nuclear's total cost would match the cost of coal and the cost of CCGT in the moderate and high gas price cases. However, nuclear does not have a meaningful economic advantage over coal.

These results suggest that with significant improvements in the costs of building, operating, and financing nuclear power plants, and continued excellent operating performance (85% capacity factor), nuclear power could be quite competitive with natural gas if gas prices turn out to be higher than what most analysts now appear to believe and would be only slightly more costly than coal within the range of assumptions identified.[14]

The cost improvements we project are plausible but unproven. It should be emphasized, that the cost improvements required to make nuclear power competitive with coal are significant: 25% reduction in construction costs; greater than a 25% reduction in non-fuel O&M costs compared to recent historical experience (reflected in the base case), reducing the construction time from 5 years (already optimistic) to 4 years, and achieving an investment environment in which nuclear power plants can be financed under the same terms and conditions as can coal plants. Moreover, under what we consider to be optimistic, but plausible assumptions, nuclear is never less costly than coal.

CARBON "TAXES"

From a societal cost perspective, all external social costs of electricity generation should be reflected in the price. Here we consider the cost of CO_2 emissions and not other externalities; for example we ignore the costs of other air pollutants from fossil fuel combustion and nuclear proliferation and waste issues (except for including the costs of new coal plants to meet new source performance standards). Nuclear looks more attractive when the cost of CO_2 emissions is taken into account. Unlike gas and coal-fired plants, nuclear plants produce no carbon dioxide during operation and do not contribute to global climate change. Accordingly, it is natural to explore what the comparative social cost of nuclear power would be, if carbon emissions were "priced" to reflect the marginal cost of achieving global carbon emissions stabilization and reduction targets.[15] Future United States policies regarding carbon emissions are uncertain at the present time.

Table 5.1 Costs of Electric Generation Alternatives
Real Levelized Cents/kWe-hr (85% capacity factor)

Base Case	25-YEAR	40-YEAR
Nuclear	7.0	6.7
Coal	4.4	4.2
Gas (low)	3.8	3.8
Gas (moderate)	4.1	4.1
Gas (high)	5.3	5.6
Gas (high) Advanced	4.9	5.1
Reduce Nuclear Costs Cases		
Reduce construction costs (25%).	5.8	5.5
Reduce construction time by 12 months	5.6	5.3
Reduce cost of capital to be equivalent to coal and gas	4.7	4.4

Carbon Tax Cases (25/40 year)

	$50/tC	$100/tC	$200/tC
Coal	5.6/5.4	6.8/6.6	9.2/9.0
Gas (low)	4.3/4.3	4.9/4.8	5.9/5.9
Gas (moderate)	4.6/4.7	5.1/5.2	6.2/6.2
Gas (high)	5.8/6.1	6.4/6.7	7.4/7.7
Gas (high) advanced	5.3/5.6	5.8/6.0	6.7/7.0

Table 5.2 Costs of Electric Generation Alternatives
Real Levelized Cents/kWe-hr (75% capacity factor)

Base Case	25-YEAR	40-YEAR
Nuclear	7.9	7.5
Coal	4.8	4.6
Gas (low)	4.0	3.9
Gas (moderate)	4.2	4.3
Gas (high)	5.5	5.7
Gas (high) advanced	5.0	5.2
Reduce Nuclear Costs Cases		
Reduce construction costs (25%)	6.5	6.2
Reduce construction time by 12 months	6.2	6.0
Reduce cost of capital to be equivalent to coal and gas	5.2	4.9

Carbon Tax Cases (25/40 year)

	$50/tC	$100/tC	$200/tC
Coal	6.0/5.8	7.2/7.0	9.6/9.4
Gas (low)	4.5/4.4	5.0/5.0	6.0/6.0
Gas (moderate)	4.7/4.8	5.3/5.3	6.3/6.4
Gas (high)	6.0/6.3	6.5/6.8	7.5/7.8
Gas (high) advanced	5.5/5.7	5.9/6.2	6.8/7.1

By examining the relative economics of nuclear power under different assumptions about future social valuations for reducing carbon emissions, we can get a feeling for the option value of nuclear generation in a world with carbon emissions restrictions of various severities.

To examine this question we have recalculated the costs of the fossil-fueled generation alternatives to reflect a carbon tax of $50/tC, $100/tC, and $200/tC. The lower value is consistent with an EPA estimate of the cost of reducing U.S. CO_2 emissions by about 1 billion metric tons per year.[16] The $100/tC and $200/tC values bracket the range of values that appear in the literature regarding the costs of carbon sequestration, recognizing that there is enormous uncertainty about the costs of deploying CO_2 capture, transport, and storage on a large scale. These hypothetical taxes should be thought of as a range of "backstop" marginal costs for reducing carbon emissions to meet aggressive global emissions goals. These results are reported in Table 5.1 and 5.2, as well.

With carbon taxes in the $50/tC range, nuclear is not economical under the base case assumptions. If nuclear costs can be reduced to reflect all of the cost-reduction specifications discussed earlier, nuclear would be less costly than coal and less costly than gas in the high gas price cases. It is roughly competitive with gas in the low and moderate price gas cases. With carbon taxes in the $100/tC to $200/tC range, nuclear power would be an economical base load option compared to coal under the base case assumptions, but would still be more costly than gas except in the high gas price case. However, nuclear would be significantly less costly than all of the alternatives with carbon prices at this level, if all of the cost reduction specifications discussed earlier could be achieved.

The last conclusion ignores one important consideration. With carbon taxes at these high levels, it could become economical to deploy a generating technology involving the gasification of coal, its combustion in a CCGT (IGCC), and

the sequestration of carbon dioxide produced in the process. The potential cost savings from this technology compared to conventional pulverized coal plants arises from (a) the use of relatively inexpensive coal to produce syngas (mostly CO and H_2) (b) the higher thermal efficiency of CCGT, and more economical capture of CO_2. Depending on the economics of this technology, coal could play a larger competitive role in a world with high carbon taxes than might be suggested by Tables 5.1 and 5.2. We observe as well, that from an environmental perspective, the world looks very different if there are abundant supplies of cheap natural gas, than if natural gas supplies are scarcer and significantly more expensive than many recent projections imply.

INTERNATIONAL PERSPECTIVE ON COST OF ELECTRICITY

The methodology followed above is pertinent to an electricity generation market that is unregulated, a situation that the United States is moving toward, as are several other countries. An additional advantage to describing deregulated market situations is that the methodology properly focuses on the true economic cost of electricity generating alternatives. There are however many nations that do not enjoy an unregulated generating market and are unlikely to adopt deregulation for some time to come. In many of these countries electricity generation is run directly or indirectly by the government and significant subsidies are provided to generating facilities. The electricity "cost" in these countries is not transparent and leads to a different political attitude toward investment decisions because consumers enjoy subsidized prices. The result is a misallocation of resources and over the long-run one can expect that political and economic forces will call for change. These non-market situations are encountered in Europe, e.g. Electricite de France, although there is a strong move to deregulation in the EU and in developing countries that frequently have state run power companies. Importantly, the costs of advanced fuel cycle technologies

Table 5.3 Base Case Assumptions

Nuclear	
Overnight cost:	$2000/kWe
O&M cost:	1.5 cents/kWh (includes fuel)
O&M real escalation rate:	1.0%/year
Construction period:	5 years
Capacity factor:	85%/75%
Financing:	
Equity: 15% nominal net of income taxes	
Debt: 8% nominal	
Inflation: 3%	
Income Tax rate (applied after expenses, interest and tax depreciation): 38%	
Equity: 50%	
Debt: 50%	
Project economic life:	40 years/25 years
Coal	
Overnight cost:	$1300/kWe
Fuel Cost:	$1.20/MMbtu
Real fuel cost escalation:	0.5% per year
Heat rate (bus bar):	9300 BTU/kWh
Construction period:	4 years
Capacity factor:	85%/75%
Financing:	
Equity: 12% nominal net of income taxes	
Debt: 8% nominal	
Inflation: 3%	
Income Tax rate (applied after expenses, interest and tax depreciation): 38%	
Equity: 40%	
Debt: 60%	
Project economic life:	40 years/25 years
Gas CCGT	
Overnight cost:	$500/kWe
Initial fuel cost:	
Low: $3.50/MMbtu ($3.77/MMbtu real levelized over 40 years)	
Moderate: $3.50/MMbtu ($4.42/MMbtu real levelized over 40 years)	
High: $4.50/MMbtu ($6.72/MMbtu real levelized over 40 years)	
Real fuel cost escalation:	
Low: 0.5% per year	
Moderate: 1.5% per year	
High: 2.5% per year	
Heat rate:	7200 BTU/kWh
Advanced:	6400 BTU/kWh
Construction period:	2 years
Capacity factor:	85%/75%
Financing:	
Equity: 12% nominal net of income taxes	
Debt: 8% nominal	
Inflation: 3%	
Income tax rate (applied after expenses, interest and tax depreciation): 38%	
Equity: 40%	
Debt: 60%	
Project economic life:	40 years/25 years

such as PUREX reprocessing and MOX fabrication are heavily subsidized reflecting political rather than economic decision making.

COST OF ADVANCED FUEL CYCLES.

We have not undertaken as complete analysis for the costs of advanced fuel cycles as we have for the open fuel cycle. We have however examined in some detail the cost of the closed fuel cycle with single pass PUREX/MOX relative to the open cycle. This analysis is reported in the Appendix 5.D.

The fuel cycle cost model presented in Appendix 5.D shows that the closed cycle PUREX/MOX option fuel costs are roughly 4 times greater than for the open cycle, using estimated costs under U.S. conditions. The closed cycle can be shown to be competitive with the once-through option only if the price of uranium is high and if optimistic assumptions are made regarding the cost of reprocessing, MOX fabrication, and high level waste disposal. As explained in Appendix 5.D, the effect of the increased MOX fuel cycle cost on the cost of electricity depends upon the percentage of MOX fuel in the entire fleet if fuel costs are blended.

The case is often advanced that disposing of reprocessed high level waste will be less expensive than disposing of spent fuel directly. But there can be little confidence today in any estimate of such cost savings, especially if disposal of non-high-level waste contaminated with significant quantities of long-lived transuranic radionuclides (TRU waste) associated with recycle facilities and operations is taken into account. Furthermore, our cost model shows that even if the cost of disposing of reprocessed high-level waste were zero, the basic conclusion that reprocessing is uneconomic would not change.

It should be noted that the cost increment associated with reprocessing and thermal recycle is small relative to the total cost of nuclear electricity generation. In addition, the uncertainty in any estimate of fuel cycle costs is extremely large.

NOTES

1. Though in the United States and the United Kingdom some nuclear plants were subsequently sold or transferred to merchant generating companies.
2. Merchant plants sell their output under short, medium and longer term supply contracts negotiated competitively with distribution companies, wholesale and retail marketers. The power plant developers take on permitting, development, construction cost and operating performance risks but may transfer some or all risks associated with market price volatility to buyers (for a price) through the terms of their contracts.
3. It is often assumed that regulated monopolies were subject to "cost-plus" regulation which insulated utilities from all of these risks. This is an extreme and inaccurate characterization of the regulatory process, at least in the United States. (P.L. Joskow and R. Schmalensee, "Incentive Regulation for Electric Utilities," *Yale Journal on Regulation*, 1986; P.L. Joskow, "Deregulation and Regulatory Reform in the U.S. Electric Power Sector," in *Deregulation of Network Industries: The Next Steps* (S. Peltzman and Clifford Winston, eds.), Brookings Press, 2000). Several U.S. utilities were faced with significant cost disallowances associated with nuclear power plants they completed or abandoned, a result inconsistent with pure cost-plus regulation. Nevertheless, it is clear that a large fraction of these cost and market risks were shifted to consumers from investors when the industry was governed by regulated monopolies.
4. The current state of electricity restructuring and competition in the United States and Europe has made it difficult for suppliers to obtain forward contracts for the power they produce. We believe that this chaotic situation is unsustainable and that a mature competitive power market will make it possible for power suppliers to enter into forward contracts with intermediaries. However, these contracts will not generally be like the 30-year contracts that emerged under regulation which obligated wholesale purchasers (e.g. municipal utilities) to pay for all of the costs of a power plant in return for any power it happened to produce. In a competitive market the contracts will be for specified delivery obligations at a specified price (or price formula), will tend to be much shorter (e.g. 5-year contract portfolios), and will place cost and operating performance risk on the generator not on the customer.

5. Oversimplifying, these effects can be thought of as an increase in the cost of capital faced by investors.

6. For example, in areas of the United States where the wholesale market tends to clear with conventional gas or oil-fired power plants on the margin, spot market clearing prices will move up and down with the price of natural gas and oil. A combined cycle gas turbine (CCGT) that also burns natural gas, but with a heat rate 35% lower on average than those of the marginal gas plants that clear the market (e.g. 11,000 BTU/kWh), will always run underneath the market clearing price of electricity. Whatever the price of gas, the CCGT is always in the money and will be economical to run under these circumstances. If gas prices go up, the CCGT will be more profitable, and if they go down it will be less profitable, but the volatility in profits with respect to changes in gas prices will be lower than that for coal or nuclear plants.

7. In 2000, the capacity factors for the nuclear plants in France were 76%, for those in Japan 79%, and for those in South Korea, 91%. Ideally, we would look at availability data, but except for France where nuclear accounts for such a large share of electricity supply that some plants must by cycled up and down, nuclear units are generally run full out when they are available (Source: Calculated from data on EIA web site.)

8. These numbers underestimate the true O&M costs of nuclear plants because they exclude administrative and general operating costs that are typically captured elsewhere in utility income statements. These overhead costs probably add another 20% to nuclear O&M costs. We do not consider these additional costs here because they are also excluded from the O&M costs for competing technologies. In a competitive power market, however, generating plants must earn enough revenues to cover these overhead costs as well as their direct capital and O&M costs.

9. That is, we are not considering competition between new nuclear plants and *existing* coal and gas plants (whose construction costs are now sunk costs). We recognize there may be economical opportunities to increase the capacity of some existing nuclear plants and to extend their commercial lives. We do not consider these opportunities here.

10. The reduced non-fuel O&M costs assumed are about 10 mills/kWh in the base case and compare favorably to 9 mills/kWh assumed by TVA (90% capacity factor) in its recent evaluation of the restart of Browns Ferry Unit #1.

11. Of course, in a competitive wholesale electricity market investors are free to act on such expectations by making financial commitments to build new nuclear plants. About 150,000 MWe of new generating capacity has been built in the U.S. in the last five years, most of it owned by merchant investors and most of it fueled by natural gas and none of it nuclear. See Paul L. Joskow, "The Difficult Transition to Competitive Electricity Markets in the U.S.," May 2003

12. We have seen some analyses that assume that nuclear plants will be financed with 100% government-backed debt, pay no income or property taxes, and have very long repayment schedules. One can make the costs of nuclear power look lower this way, but it simply hides the true costs and risks of the projects which have effectively been transferred to consumers and taxpayers.

13. This brings the nuclear plant cost down to $1500/kW. This is roughly the cost used in the analysis of the costs of a new nuclear power plant in Finland at current exchange rates. (However, the Finnish analysis assumes that the plant can be financed with 100% debt at a 5% real interest rate and would pay no income taxes). Note, however, that TVA estimates that the costs of *refurbishing* a mothballed unit at Browns Ferry will cost about $1300/kWe, and that recent Japanese experience is closer to the $2000/kWe base case assumption. TVA's analysis of the costs of refurbishing the Browns Ferry unit assume that the project can be financed with 100% debt at an interest rate 80 basis points above 10-year treasury notes and would pay no taxes.

14. Obviously, there is some set of assumptions that will make nuclear cheaper than coal. However, they basically require driving the construction costs and construction time profile to be roughly equivalent to those of a coal unit. We also have not assumed any improvements in construction costs or heat rates for coal units associated with advanced coal plant designs.

15. We have modeled the carbon "price" as a carbon dioxide emissions tax. However, the intention is to simulate any policies that give nuclear power "credit" relative to fossil fuel alternatives for producing no CO_2.

16. "Summary and Analysis of McCain-Leiberman 'Climate Stewardship Act of 2003'," William Pizer and Raymond Kopp, Resources for the Future, January 28, 2003.

Appendix Chapter 5 — Economics

Appendix 5.A — Calculation of the Levelized Cost of Electricity

The real levelized cost of electricity production is used to assess the economic competitiveness of alternative generating technologies.[1] The real levelized cost of a project is equivalent to the constant dollar ("real") price of electricity that would be necessary over the life of the plant to cover all operating expenses, interest and principal repayment obligations on project debt, taxes and provide an acceptable return to equity investors over the economic life of the project. The real levelized cost of alternative generating technologies with similar operating characteristics (e.g. capacity factors) is a metric used to identify the alternative that is most economical.

A project's real levelized cost can be computed using discounted cash flow analysis, the method employed in the model described below. Revenues and expenses are projected over the life of the project and discounted at rates sufficient to satisfy interest and principal repayment obligations to debt investors and the minimum hurdle rate (cost of equity capital) required by equity investors.

An alternate method, based on traditional regulated utility revenue requirement calculations, is often used to calculate levelized costs for generating technologies. This approach has two problems: First, it fails to account properly for inflation and yields levelized nominal cost numbers that cannot easily be compared across technologies with different capital intensities. Second, it imposes a particular capital cost repayment profile that, while consistent with the way regulated investments were treated, is not consistent with the merchant generation investment environment that now characterizes the U.S., Western Europe and a growing number of other countries.

The spreadsheet model used to calculate real levelized costs for nuclear, coal, and natural gas-fired power plants is described in the following sections. Table A-5.A.1 defines variables used throughout the appendix. The cash flows are first generated in nominal dollars in order to calculate income taxes properly and then adjusted to constant real prices using the assumed general inflation rate (3% in the examples below).

Table A-5.A.1 Model Variables

C_O	Overnight cost ($/kWe)	HR	Heat rate (BTU/kWh)
T_C	Construction time (years)	C_{Fuel}	Unit cost of fuel ($/mmBTU)
C_{TOT}	Total construction cost ($/kWe)	C_{Waste}	Nuclear waste fee (mills/kWh)
D/V	Debt fraction of initial investment	C_{OMf}	Fixed O&M ($/kWe/yr)
E/V	Equity fraction of initial investment	C_{OMv}	Variable O&M (mills/kWh)
r_D	Nominal cost of debt	C_{Incr}	Incremental capital costs ($/kWe/yr)
r_E	Nominal cost of equity	C_{Decom}	Decommissioning cost ($million)
N	Plant life (years)	τ_{Carbon}	Carbon emissions tax ($/tonne-C)
L	Plant net capacity (MWe)	I_{Carbon}	Carbon intensity of fuel (kg-C/mmBTU)
Φ	Capacity factor	R_n	Revenues in period n
p_n	Nominal price of electricity in period n	I_n	Interest payment in period n
τ	Marginal composite corporate income tax rate	$C_{n,Op}$	Total operating expenses in period n

CAPITAL INVESTMENT

Power plants require significant capital investments before electricity production can begin. The cash flow model allocates the overnight cost of the plant, C_O, specified in \$/kWe of the year production begins (2002), over the construction period, T_O, allowing for an additional period after construction for final licensing and testing. By convention, all investment expenditures are counted at the beginning of the year in which they occur, and all revenues and operating expenses are assumed to occur at the end of the year. Numerous construction expenditure profiles are available in the model, including a uniform profile and one that peaks at mid-construction, characterized by a sinusoidal function. The annual capital expenditures for the nuclear plant costing \$2,000/kWe in base year prices (2002) and a combined-cycle gas turbine (CCGT) plant costing \$500/kWe are presented in Table A-5.A.2.

Table A-5.A.2 Representative Construction Outlays (nominal dollars)

YEAR	-5 \$/kWe	-4 \$/kWe	-3 \$/kWe	-2 \$/kWe	-1 \$/kWe	TOTAL OUTLAY (mixed \$/kWe)	OVERNIGHT COST (2002 \$/kWe)	TOTAL COST (2002 \$/kWe)
Nuclear	165	444	566	471	185	1,831	2,000	2,557
CCGT	0	0	0	236	243	478	500	549

Nuclear: 5 year construction period, sinusoidal profile, i = 3%
CCGT: 2 year construction period, uniform profile, i = 3%

Note that the overnight cost is specified in constant dollars of the year production begins (year 2002 \$), and so the capital expenditure in each year is deflated to current-year (nominal) dollars. This explains why the total outlay in nominal dollars is numerically smaller than the overnight cost.

$$X_n = F_n C_O (1 + i)^n$$

where X_n is the outlay in year n (n = 0 in 2002, n < 0 during construction), F_n is the fraction of the overnight cost allocated to year n, and i is the rate of general inflation. In order to finance construction, the project takes on debt obligations and attracts equity investors with certain requirements. Debt and equity each have an expected minimum rate of return and debt has a specified repayment period. The interest on debt and imputed interest on equity are added to the overnight cost to find the total cost of construction.

$$C_{TOT} = \sum_{n<0} X_j (1 + r_{eff})^{-n} \qquad r_{eff} = \frac{D}{V} r_D + \frac{E}{V} r_E$$

employing an effective interest rate r(eff). The total cost of construction does not represent true cash flows but is a measure of construction cost taking into account the time value of money. The total costs in the Table A-5.A.2 correspond to 50/50 debt/equity, $r_D = 8\%$, $r_E = 15\%$ for the nuclear case ($r_{eff} = 11.5\%$) and 60/40 debt/equity, $r_D = 8\%$, $r_E = 12\%$ for the CCGT case ($r_{eff} = 9.6\%$).

ASSET DEPRECIATION

Once put in service, the power plant depreciates according to a specified schedule. The treatment of depreciation is important in the calculation of the annual tax liability, since asset depreciation is a tax-deductible expense. In the base case model we use accelerated depreciation, based on Modified Accelerated Cost Recovery System (MACRS) guidelines, assuming a 15 year asset life. The total capital expenditure (excluding interest and equity appreciation) during construction is used as the depreciable asset base. The depreciable asset base is based on nominal rather than real expenditures. So, for example, if the base year overnight construction cost is $2,000/kW and inflation is 3% per year, the depreciable asset base will be less than the overnight cost in base year prices, to reflect the fact that actual expenditures will be made during earlier years with lower nominal prices.

REVENUES

The sole source of revenue for the power plant is the sale of electricity. The price of electricity in 2002 is determined in an iterative process such that required returns to investors are met. This price, p, is equivalent to the levelized cost of the plant. In order to represent a real levelized cost, the price of electricity escalates at the rate of general inflation.

Annual revenue is the product of the quantity of electricity produced and its price. The plant's net capacity and capacity factor determine the annual electric generation.

$$Q = \frac{L}{10^3} \cdot \Phi \cdot 8{,}760 \frac{hours}{year} \quad (GWh/year)$$

$$R_n = Qp_n \quad p_n = p_n (1 + i)^n$$

where the rated capacity, L, is specified in MWe. A 1,000 MWe plant with an annual capacity factor of 85% produces 7,446 GWh of electricity per year.

OPERATING EXPENSES

Operating expenses are incurred throughout the operational life of the plant and include fuel, operating and maintenance costs, and decommissioning funds. Carbon emissions taxes and incremental capital expenditures similarly are treated as operating expenses. (Treating incremental capital expenditures as operating expenses instead of additions to the depreciable asset base is a simplification to avoid having to specify additional depreciation schedules. Because expenditures are assumed to occur every year, the error introduced is small.) Non-fuel operating expenses can be broken down into fixed and variable cost components and are generally assumed to increase at the rate of inflation, though in some cases a real escalation rate is included. The assumed escalation of real fuel prices is a variable input to the model. This is particularly useful in the CCGT case where increases in natural gas prices have a large impact on the levelized cost of generation. Table A-5.A.3 lists the plant's operating expenses along with their arithmetic expressions.

Table A-5.A.3 Operating Expenses

EXPENSE	VALUE IN YEAR n ($million)	NOTATION
Fuel	$\frac{C_{Fuel} \cdot HR \cdot Q \cdot (1+e_f)^n}{10^6}$	$C_{n,\,fuel}$
Waste fund[a]	$\frac{C_{Waste} \cdot Q \cdot (1+i)^n}{10^3}$	$C_{n,\,waste}$
Fixed O&M	$\frac{C_{OMf} \cdot L \cdot (1+e_{om})^n}{10^6}$	$C_{n,\,omf}$
Variable O&M	$\frac{C_{OMv} \cdot Q \cdot (1+e_{om})^n}{10^6}$	$C_{n,\,omv}$
Decommissioning[a, b]	$C_{Decom} \cdot (1+i)^N \cdot SFF_0$	$C_{n,\,decom}$
Incremental capital	$C_{Incr} \frac{L}{10^3} \cdot (1+i)^n$	$C_{n,\,incr}$
Carbon emissions tax	$\frac{\tau_{Carbon}\, I_{Carbon}}{10^9} \cdot HR \cdot Q \cdot (1+i)^n$	$C_{n,\,carbon}$

a. Specific to nuclear plants
b. SFF_0 is the sinking fund factor for N years at the risk free rate.

Total operating expenses are:

$$C_{n,Op} + C_{n,fuel} + C_{n,waste} + C_{n,omf} + C_{n,omv} + C_{n,decom} \quad \$million$$

Total operating expenses, $C_{n,\,op}$, incremental capital expenditures, and carbon emissions taxes are subtracted from revenues before computing the annual tax liability. Two other adjustments are made to taxable income. Asset depreciation, D_n, and interest payments I_n to creditors are both treated as tax-deductible expenses and thus reduce taxable income. The tax liability, T_n, is simply the product of taxable income and the composite marginal corporate income tax rate,, assumed to be 38% in the base cases.[2]

$$T_n = \tau\left[R_n - C_{n,Op} - C_{n,incr} - C_{n,carbon} - D_n - I_n\right]$$

A production tax credit is available in the model to simulate, along with the carbon emissions tax, public policies to curb CO_2 emissions.

INVESTOR RETURNS

The model solves for a constant real price of electricity sufficient to provide adequate returns to both debt and equity investors.[3] Interest on debt accrues during construction and is repaid with the principal in equal annual payments over the specified term of the debt. Equity holders invest funds during construction and receive profits net of taxes and debt obligations during plant operation. Net profits over the life of the project are such that the internal rate of return (IRR) of the equity holders' cash flows equals the required nominal return; 15% in the nuclear base case and 12% in the fossil cases. The model includes a constraint that the debt payment obligations specified are made in full each year (the project is not allowed to default on debt obligations). For example, assume that the

Table A-5.A.4 Base Case Input Parameters

YEAR	NUCLEAR	COAL	NGCC
Inflation rate	3%	3%	3%
Interest rate	8%	8%	8%
Expected return to equity investor	15%	12%	12%
Debt fraction	50%	60%	60%
Tax rate	38%	38%	38%
Debt term	10 years	10 years	10 years
Net capacity	1,000 MWe	1,000 MWe	1,000 Mwe
Capacity factor	85%	85%	85%
Plant life	40 years	40 years	40 years
Heat rate	10,400	9,300	7,200
Overnight cost	$2,000/kWe	$1,300/kWe	$500/kWe
Construction period	5 years	4 years	2 years
Post-construction period	—	—	—
Depreciation schedule	Accelerated, 15 years	Accelerated, 15 years	Accelerated, 15 years
Decommissioning cost	$350 million	—	—
Incremental capital costs	$20/kWe/yr	$15/kWe/yr	$6/kWe/yr
Fuel costs	$0.47/mmBTU	$1.20/mmBTU	$3.50/mmBTU
Real fuel escalation	0.5%	0.5%	1.5%
Nuclear waste fee	1 mill/kWh	—	—
Fixed O&M	$63/kWe/yr	$23/kWe/yr	$16/kWe/yr
Variable O&M	0.47 mills/kWh	3.38 mills/kWh	0.52 mills/kWh
O&M real escalation rate	1.0%	1.0%	1.0%
Carbon intensity	—	25.8 kg-C/mmBTU	14.5 kg-C/mmBTU
Carbon tax	—	—	—

Note: Compiled from public information, including reports from the Energy Information Administration.

model solves for a constant real price of electricity that satisfies the return required by equity holders. In most cases, the solution would be deemed the levelized cost of electricity. However, if the resultant operating income (revenues less operating expenses) is insufficient to cover the entire debt payment in any year, the electricity price is raised until all debt payments can be made. If the debt service constraint is binding, the realized return on equity will then exceed the minimum required return specified.

Since the purpose of the levelized cost calculation is to compare alternative generating technologies and assess their potential contribution to future energy supply, the technologies compared must generate electricity over equivalent time periods. In order to maintain the level basis for comparison, plants are not allowed to shut down prematurely when operating expenses exceed revenues, as in the case of escalating natural gas prices. The result in these situations is a cash flow stream for the project that does not reflect expected business decisions. Nonetheless, for comparison of future electricity supply options, it is more appropriate to include the effect of high natural gas prices in the out years than to exclude it by running the plant shorter than its projected life. In this case, the plant must still meet all debt obligations and a minimum return on investment to equity investors.

Table A-5.A.5 Nuclear Base Case Cash Flows (nominal dollars)

YEAR	1	2	3	5	10	20	30	40
Electricity price (cents/kWh)	6.91	7.12	7.33	7.78	9.02	12.12	16.28	21.88
Revenue ($million)	515	530	546	579	672	903	1,213	1,631
Operating expenses ($million)								
- Fuel cost	38	39	40	43	51	73	103	145
- Waste fee	8	8	8	9	10	13	18	24
- Fixed O&M	66	68	71	77	94	139	206	306
- Variable O&M	4	4	4	4	5	8	11	17
- Decommissioning	9	9	9	9	9	9	9	9
- Incremental cap.	21	21	22	23	27	36	49	65
Operating income	370	381	391	414	475	625	817	1,063
Depreciation (tax)	92	174	157	127	108	0	0	0
Interest payments	92	86	79	64	13	0	0	0
Debt principal repayment	80	86	93	108	159	0	0	0
Taxable income	186	121	156	223	354	625	817	1,063
Income tax payment	71	46	59	85	135	237	310	404
Net profit	127	163	160	157	169	387	506	659

Table A-5.A.6 CCGT Base Case Cash Flows (nominal dollars)

YEAR	1	2	3	5	10	20	30	40
Elec. price (cents/kWh)	4.25	4.38	4.51	4.78	5.54	7.45	10.01	13.45
Revenue ($million)	317	326	336	356	413	555	746	1,003
Operating expenses ($million)								
- Fuel cost	196	205	215	234	293	457	712	1,111
- Waste fee	—	—	—	—	—	—	—	—
- Fixed O&M	16	17	18	19	23	34	51	76
- Variable O&M	4	4	4	5	6	9	13	19
- Decommissioning	—	—	—	—	—	—	—	—
- Incremental cap.	6	6	7	7	8	11	15	20
Operating income	94	93	93	91	83	45	-45[a]	-223[a]
Depreciation (tax)	24	45	41	33	28	0	0	0
Interest payments	26	24	22	18	4	0	0	0
Debt principal repayment	22	24	26	30	44	0	0	0
Taxable income	44	24	30	40	51	45	0	0
Income tax payment	17	9	11	15	20	17	0	0
Net profit	29	36	33	28	16	28	-45[a]	-223[a]

a. For the purposes of comparing energy supply options, plant operation is not terminated when operating costs exceed revenues.

Appendix 5.B – Nuclear Power Plant Construction Costs

This section contains a summary of available information on nuclear power plant construction costs. The information includes construction cost estimates by government and industry sources, actual cost data from recent experience abroad, and some recent indications of the current market valuation of nuclear plants. The data are somewhat sparse but are helpful in determining what nuclear plants cost to build now, what they are projected to cost in the future, and what cost will make nuclear viable in a competitive electricity generation market. Cost figures are presented in a variety of formats (overnight costs, total construction costs, levelized costs) in the sources cited and are generally presented in the format given by the source.

CONSTRUCTION COST FORECASTS

EIA — Annual Energy Outlook 2003[4]
Cost and performance characteristics for nuclear plants in the Annual Energy Outlook are based on current estimates by government and industry analysis. Two cost cases are analyzed, the reference case and an advanced nuclear cost case, where overnight costs are reduced to be consistent with the goals endorsed by DOE's Office of Nuclear Energy.

In the reference case, overnight construction costs are predicted to be $2,044/kWe in 2010 and $1,906/kWe in 2025, specified in 2001 dollars. Construction costs are assumed to decline over time based on a representative learning curve. The overnight costs reported include a 10% project contingency factor and a 10% technological optimism factor, which is applied to the first four units to reflect the tendency to underestimate costs for a first-of-a-kind unit. The report indicates a five year lead time for construction. Predicted overnight costs for the advanced nuclear case are $1,535/kWe in 2010, dropping to $1,228/kWe by 2025, also reported in 2001 dollars. The advanced case does not include a technological optimism factor.

DOE-NE — 2010 Roadmap Study[5]
The economic analysis in the 2010 Roadmap study takes a parametric approach to nuclear capital costs, but states that engineering, procurement, and construction costs vary between $800 and $1,400 / kWe. Adding 20 percent for owner's costs and project contingency, the approximate range for overnight costs is $1,000–$1,600 / kWe in 2000 dollars. Construction is assumed to occur over 42 months, with six months between construction and commercial operation.

In addition to the parametric analysis, the 2010 Roadmap study evaluated eight advanced nuclear plant designs as candidates for near term deployment. The cost estimates for the new designs were provided by vendors with various levels of confidence and detail. A brief summary of relevant information for the eight designs is tabulated in Table A-5.B.1.

Table A-5.B.1

DESIGN	OVERNIGHT COST	OTHER RELEVANT INFORMATION
GE ABWR	$1,400–$1,600/kWe	48 month construction (Japan) Real construction experience
GE ESBWR	Lower than ABWR	Availability goal of 92% Simplified design to reduce cost
Framatome SWR-1000	$1,150–$1,270/kWe FOAK[a] 15-20% reduction for NOAK[b]	Cost excludes cooling tower 48 month construction, 91% avail.
Westinghouse AP600	$2,175/kWe FOAK $1,657/kWe NOAK	5 years from order placement to commercial operation
Westinghouse AP1000	$1,365/kWe FOAK $1,040/kWe NOAK	Cost assumes twin units, includes owner's costs and contingency
Westinghouse IRIS	$687–$1,224/kWe FOAK $746–$1,343/kWe NOAK	100-300 MWe plant availability 85-99%
Pebble Bed Modular Reactor	$1,250/kWe NOAK	110 MW units
General Atomics GT-MHR	$1,122/kWe 25% reduction for NOAK	Cost includes contingency and owner's costs

a. FOAK - First-of-a-kind
b. NOAK - Nth-of-a-kind

NEA/IEA — Projected Costs of Generating Electricity[6]

The estimates of construction and operating costs for power plants contained within the NEA/IEA report are compiled from OECD countries and are based on a combination of engineering estimates, paper analyses, and industry experience. The authors decompose the cost submissions and recompile them using standard assumptions and two real discount rates, 5% and 10%. Not every country includes the same cost items in its totals, making comparisons across countries difficult, and all costs are converted to US dollars using a spot exchange rate. Cost estimates are listed for the United States and for the entire OECD range. (See Table A-5.B.2.) Costs for closed fuel cycles are not included in the range of estimates. The costs reported in the NEA/IEA report are identical to those in the NEA report *Nuclear Power in the OECD*, published in 2001.

Table A-5.B.2

PARAMETER	UNITED STATES	OECD
Base year for costs	1996	1996
Capacity factor	75%	75%
Overnight cost[a]	$1,585 / kWe	$1,585 – $2,369 / kWe
Overnight cost (2002 dollars)	$1,831 / kWe	$1,831 – $2,737 / kWe
Total construction cost (2002 dollars)	$2,139 / kWe	$2,139 – $3,101 / kWe
Construction period	4 years	4 – 9 years

a. Includes owner's costs and a contingency factor.

Finland

The Finnish parliament in May 2002 approved construction of a new nuclear power plant by the electric utility Teollisuuden Voima Oy (TVO), based in part on the economic analysis of generation options by Risto Tarjanne of the Lappeenranta University of Technology, Finland.[7] A fifth nuclear unit is seen as the superior generation choice to limit imports of Russian natural gas, allow Finland to meet Kyoto Protocol commitments, and guarantee cheap electric power to the Finnish industry. It is important to note that TVO is a non-profit company that provides electricity to its industrial shareholders at cost, effectively providing a long-term power purchase agreement not likely available to plant owners in a competitive environment.

The economic analysis supporting the decision to build a fifth nuclear reactor compares the economics of a new nuclear plant to a pulverized coal plant, a combined-cycle gas turbine plant, and a peat-fired plant. Low nuclear construction and operating costs, high plant performance, and a 5% real discount rate contributed to nuclear power being the superior choice. The study assumed an initial nuclear investment cost of 1,749 euros/kWe, including interest during construction, and a five year construction period. Using an exchange rate of 1.0 euro / U.S. dollar and inflating to 2002 dollars, the total construction cost used in the analysis is roughly $1,830/kWe, implying an overnight cost of about $1,600/kWe.[8]

UK Energy Review

The UK Performance and Innovation Unit's Energy Review addresses the construction cost of nuclear plants by evaluating submitted estimates from British Energy and BNFL.[9] The report first notes that the construction cost for Sizewell B, completed in 1994, was £3,000/kWe in 2000 money ($US 5,000/kWe at current exchange rates), including first-of-a-kind (FOAK) costs (£2,250/kW excluding FOAK costs or $US3,700/kWe at current exchange rates), for a total cost of generation around 6p/kWh or 9.6 ¢US/kWh at current exchange rates (excluding FOAK costs). Industry (British Energy and BNFL) now predicts that the Westinghouse AP1000 could generate electricity at 2.2-3.0 p/kWh or 3.3 to 4.8 ¢US/kWh ignoring FOAK costs. The construction costs assumed in these estimates were considered commercially confidential and were not included in the report. The PIU report notes that the construction costs provided by the industry were better than the best recent estimates from OECD countries,[10] and that operating availability estimates were questionably high. The PIU analysis suggests a range of 3p/kWh to 4p/kWh (or 4.8 to 6.4 ¢US/kWh for future nuclear cost of generation, consistent with total construction costs of roughly £1,400–1,700/kWe in 2000 money, or about $2,300–$2,900/kWe at current exchange rates.

RECENT MARKET VALUATION OF NUCLEAR PLANTS

Sale of Seabrook Nuclear Station – 2002

In 2002, 88.2% ownership of Seabrook Nuclear Station (1,024 MWe) was transferred to Florida Power & Light through a competitive auction process. The sale price was $749.1 million for the operating plant ($730/kWe), plus $25.6 million for components from an uncompleted unit and $61.9 million for nuclear fuel. The deal included no power purchase agreement. FP&L will receive the current balance of the decommissioning trust fund, esti-

mated at $232.7 million. The NRC operating license for Seabrook is set to expire in October 2026, allowing for more than 20 years of service with the possibility of a 20-year license extension. This implies that the market value of a fully licensed and operating nuclear power plant with a good performance record is less than half of the most optimistic cost estimates for building a new nuclear power plant and only about 30% more than the cost of CCGTs being built in New England during this time period. This in turn implies that merchant investors in nuclear power plants believe either (a) that future operating costs are much higher than is assumed in engineering cost studies or (b) that the commercial risks associated with even a licensed and operating plant are so high that a very high cost of capital is imputed to future cash flows, or a combination of both. Comparable analyses of other recent nuclear power plant sales come to very similar conclusions. The market value of nuclear plants is far below their replacement cost, a result that is inconsistent with merchant investment in new nuclear plants.

Browns Ferry Unit 1 Restart -- TVA

In May 2002, the TVA board of directors approved a plan to restart Browns Ferry Nuclear Unit 1, idle since 1985. The decision was based on recent improvements in nuclear operating performance and costs at TVA plants and a reduced estimate of the cost to restart the unit. The analysis tiered from Energy Vision 2020, TVA's resource integration plan, which in 1995 recommended deferring a decision on Browns Ferry Unit 1 until more data could be collected on operating performance and costs. Browns Ferry Unit 1 has an active NRC operating license that will expire in 2013, but TVA plans to apply for a 20-year license extension if the unit is recovered.

The new analysis estimates that the restart of BFN Unit 1 will cost between $1.56 and $1.72 billion in 2002 dollars and will take 5 years to complete.[11] This corresponds to an overnight capital cost of about $1,280/kWe. The 2002 TVA report indicates that the levelized cost of the project will be less than that of an alternative natural gas-fired combined cycle plant, based on a financial research report quoting the levelized cost of a combined cycle plant as $51.00/MWh.[12]

The crucial factors that makes nuclear competitive in this case are (a) that the expenditures are required to upgrade an existing plant that already has significant capital facilities in place and (b) TVA's assumed low cost of capital. The restart will be financed entirely with debt, TVA is able to borrow money very cheaply, and the company doesn't pay federal income taxes or local property and sales taxes.[13] Coupling their low cost of capital with recent experience of high performance and low operating costs, nuclear appears to be the low-cost option.

RECENT NUCLEAR CONSTRUCTION ABROAD

A few countries are actively building nuclear plants using new nuclear designs and advanced construction techniques to which estimated cost reductions are attributed. Unfortunately, actual cost data for these projects is difficult to acquire. Project costs for newly operating plants in Japan and South Korea are discussed in this section and should provide some evidence as to whether projected cost reductions are being realized.

It is important to note the difficulty in comparing costs of construction projects across countries. Differences in the relative costs of local resources and construction technologies, government regulations, labor productivity, and the fact that a large fraction of nuclear plant costs depend on local labor and construction resources and are not tradeable across countries are such that the costs of construction projects in different countries must be compared with great care. Currency exchange rates may not accurately reflect the relative costs of goods and services that are not traded internationally, and are susceptible to rapid fluctuations that obscure real costs.[14] An alternative approach to international comparison is the use of purchasing power parities (PPP) that adjust for price level differences between countries and thus attempt to equalize the purchasing power of different currencies. The Japanese and Korean construction cost data below are interpreted using PPPs compiled by the OECD and Eurostat for gross fixed capital formation, including construction, machinery, and equipment.[15] The PPPs are assembled every three years based on prices of representative goods, services, and projects, provided by participating countries. The use of PPPs for international comparisons of construction projects does not resolve all regional differences, but is generally expected to be more consistent and perhaps more accurate than using current exchange rates alone.

Japanese Nuclear Plant Construction

Japan is one of the few countries actively building nuclear plants at this time.

Construction costs for recent nuclear plants by Tohoku and Kyusyu utilities were compiled for us by a Japanese analyst from public information and are tabulated below.

Table A-5.B.3

OWNER	NAME OF PLANT	CAPACITY	COMMERCIAL OPERATION DATE	TOTAL PROJECT COST (109 YEN)	U.S. EQUIVALENT[a]
Tohoku Electric	Onagawa 3 (BWR)	825 MWe	January 2002	314	$2,409/kWe
Kyusyu Electric	Genkai 3 (PWR)	1,180 MWe	March 1994	399	$2,818/kWe
	Genkai 4 (PWR)	1,180 MWe	July 1997	324	$2,288/kWe

Note: Compiled from public information by the MIT Center for Energy and Environmental Policy Research.
a: Using PPP of 158 yen / U.S. dollar.

Recent data for BWR plants built for Tokyo Electric Power Company (TEPCO) at its Kashiwazaki-Kariwa Nuclear Power Station is given next. Units 3 and 4, both 1,000 MWe BWR designs, were completed in 1993 and 1994 respectively. More interesting for our purposes, units 6 and 7, GE 1,356 MWe ABWR designs, were completed in 1996 and 1997. Approximate costs of constructing the reactors come from multiple sources, all of which give values within a modest range of each other: TEPCO annual reports, publicly available data on reactor costs from TEPCO, and direct communications with TEPCO.

Data contained in TEPCO's Annual Reports were analyzed as follows. Incremental capital costs were estimated based on the average increase in nuclear asset values in years in which reactors were not added to the asset base. This quick approach resulted in incremental capital costs on the order of current data in the United States. Subtracting incremental capital costs from the annual increase in nuclear assets produced an estimate of the construc-

tion cost for each plant in the year it began construction. Several factors may skew the construction cost estimate, but they are not seen as significant within the scope of the study. Estimates of interest during construction in Japan during this time period are low, and so whether or not it is capitalized and included in the asset balance will have only a minor effect. Inflation was ignored, as it has been low in Japan over this period as well. The annual reports yielded construction costs of 320-340 billion yen each for units 3 and 4, and 400-420 billion yen each for units 6 and 7. Using a PPP of 158 yen / U.S. dollar,[16] construction costs were equivalent to $US1,800–$US2,000/kWe for the ABWR units.

TEPCO presents rough figures for construction costs of each plant on its website. The approximate costs presented are 325 billion yen for Kashiwazaki-Kariwa (KK) 3, 334 billion yen for KK4, 418 billion yen for KK6, and 367 billion yen for KK7. These values are close to those derived from the annual reports, with the exception of KK7 at $1,710/kWe, using the same PPP as above. Information compiled for us by a Japanese analyst from public information confirms these estimates: 433 billion yen for KK6 ($2,020/kWe) and 384 billion yen for KK7 ($1,790/kWe).

Korean Nuclear Plant Construction

South Korea possesses 18 operating nuclear reactors with two more planned to connect to the grid in 2004/2005. The latest reactors, Yonggwang 5 & 6, are 1,000 MWe PWRs, using the Korean Standard Nuclear Power Plant (KSNP) design, based on the Combustion Engineering System 80. The Yonggwang plant is owned and operated by Korea Hydro & Nuclear Power, a subsidiary of Korea Electric Power (KEPCO). KEPCO is a state-run monopoly that is in the process of privatizing its power generation business. The construction was financed through debt.

Construction of the two reactors cost an estimated 3.91 trillion Korean won. The overnight cost is estimated at 3.11 trillion won at 2002 price levels.[17] Using a PPP of 867 won / U.S. dollar,[18] the unit overnight cost is equivalent to about $1,800 / kWe and the total construction cost is equivalent to about $2,300 / kWe. Care should be taken when attempting to apply these cost figures to construction in other parts of the world, because the challenges of international comparisons discussed above become more significant when developing countries are being considered.

Appendix 5.C — Nuclear Power Plant Operating Costs

Nuclear power plant operating costs are generally assumed to be more predictable than those of fossil plants, due to relatively stable fuel prices. This appendix presents several estimates of historical operating costs and projections of future costs for nuclear plants. The focus is on non-fuel operating and maintenance (O&M) costs. Some sources record non-fuel operating costs while others include the cost of fuel. For purposes of comparison, nuclear fuel costs can be assumed to be in the range of 5-6 mills/kWh.

Recent performance of nuclear plants indicates that *non-fuel* O&M costs averaged between 12 and 18 mills/kWh. Costs for the best plants have been below 8 mills/kWh while costs for the worst plants have exceeded 25 mills/kWh. Projections of future costs tend toward the low end of this range and below, with some projections as low as 5 mills/kWh for non-fuel O&M.

EIA — ELECTRIC POWER ANNUAL 2001

The Energy Information Administration (EIA) reports average operating costs for major U.S. investor-owned electric utilities in its *Electric Power Annual.*[19] The current Annual reports average operating costs for the period 1990–2001, based on utility filings of FERC Form 1, *Annual Report of Major Electric Utilities, Licensees, and Others.* Non-fuel O&M costs for nuclear plants averaged 18 mills/kWh, adjusted to 2002 dollars, for the period 1990–2001, and have declined in each of the past five years. For the five year period ending in 2001, non-fuel O&M costs averaged 16 mills/kWh and the average has dropped to 14 mills/kWh since 2000. For comparison, fossil steam plant O&M costs averaged around 6 mills/kWh for the 12 year period, excluding fuel costs.

Table A-5.C.1 Nuclear Power Plant Operating Costs, 1990–2001

(mills/kWh)	1999	2000	2001	1990–2001 AVERAGE	1997–2001 AVERAGE
Non-fuel O&M	14.1	13.3	13.3	15.3	14.9
- 2002 dollars	**15.2**	**14.0**	**13.6**	**18.1**	**16.1**
Fuel costs	5.2	5.0	4.7	5.7	5.1
Total operating costs	19.2	18.3	18.0	21.0	20.0

Source: EIA, Electric Power Annual 2001

EIA — NUCLEAR POWER PLANT OPERATING COSTS

The EIA report, *An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update,*[20] provides more detailed information on nuclear plant operating costs, though the analysis is limited to pre-1994 data. As in the *Electric Power Annual,* utility data are collected from FERC Form 1 filings and historical trends in operating costs are analyzed. Between 1974 and 1984, real non-fuel O&M costs escalated at an annual rate of 12%, and increased regulatory action was cited as the major factor causing the cost escalation. Over the last five years of the sample period (1989–1993), O&M costs escalated by less than 1% annually, with a cost of $96/kW in 1993 (equivalent to 13 mills/kWh for 85% capacity factor).

The 1995 report offers a number of interesting statistics about nuclear O&M costs. First, the report lists O&M costs for individual plants over the last four years. From these data, it can be seen that O&M costs for the best performer are just over half (56%) of the average costs across the fleet. Costs for the lowest cost quartile are 20% below average, 16% above average for the highest cost quartile, and 86% above average for the worst performer.

Second, a regression analysis determines that plant aging, NRC regulatory activity, and regulatory incentives to improve performance were the three most important factors influencing changes in O&M costs over time.[21] It is estimated that 67% of the reported O&M costs are labor related, with the remaining 33% for expenditures on maintenance materials and supplies.

Third, and most important for assessing the total cost of nuclear generation, the report lists cost items that are not included in the reported O&M costs. Insurance premiums for property damage, third-party damages, and replacement power in case of an accident are not included. Additionally, NRC regulatory fees and some payroll taxes and fringe benefits are not included because they are reported in aggregate for the utility. A study performed by Oak Ridge National Laboratory estimated that the reported O&M costs understate the actual costs by up to 30%.[22]

NUCLEAR ENERGY INSTITUTE (NEI)

NEI presents 3-year rolling average production costs for U.S. nuclear plants based on data from the Utility Data Institute and the Electric Utility Cost Group.[23] The table shows consistent cost reductions across the fleet. The fleet average production cost for 1998–2000 was 17.4 mills/kWh, including fuel costs. However, the lowest cost quartile achieved total O&M costs of about 13 mills/kWh and the second lowest cost quartile 15 mills/kWh.

Table A-5.C.2 3-year Rolling Average O&M Costs for U.S. Nuclear Plants

(mills/kWh)	1st QUARTILE	2nd QUARTILE	3rd QUARTILE	4th QUARTILE
1996–1998	14.3	16.9	20.4	38.8
1997–1999	13.3	15.8	18.4	28.0
1998–2000	12.7	15.0	17.3	24.6

OPERATING COST PROJECTIONS

The most recent projections from EIA are for fixed nuclear O&M costs of $58/kW and variable O&M costs of 0.43 mills/kWh.[24] Assuming an 85% average capacity factor, this is equivalent to 8 mills/kWh (excluding fuel). The economic analysis in the Department of Energy 2010 Roadmap study pushes operating costs down further by projecting non- fuel O&M costs around 5 mills/kWh for near term deployment plants.[25] The report notes that this is in line with the best currently operating plants. And TVA, in its evaluation of the proposed restart of Browns Ferry Unit 1, projects O&M costs below 8 mills/kWh, based on recent experience at its other nuclear facilities. These operating cost projections are significantly below the actual operating cost numbers drawn from recent experience displayed above.

Appendix Chapter 5.D — Costs of Reprocessing

Spent UOX fuel typically contains a little over 1% Pu. Through reprocessing (PUREX process), it is possible to recover this plutonium and use it to make MOX fuel for use in LWRs. However, because of the high costs of reprocessing and of MOX fuel fabrication, the cost of repository disposal must be very high in order for the MOX option to become economically competitive with the once-through UOX cycle. We support this conclusion with the following analysis.

Fuel Cycle Cost Model — A simple expression for the fuel cycle cost is as follows:

$$FCC = \sum_i M_i \cdot C_i + \sum M_i \cdot C_i \cdot \phi \cdot \Delta T_i \quad [\$]$$

where:

FCC = Fuel Cycle Cost [$]

M_i = mass processed at stage i [kg or kg SWU]

C_i = unit cost at stage i [$/kg or $/kg SWU]

ϕ = carrying charge factor (yr^{-1})

ΔT_i = delay between the investment for stage i and the midpoint of the irradiation of the fuel (years)[26]

UOX cycle — The once-through UOX cycle is represented below (for 1 kgIHM[27] of fuel):

Assumptions

- U235 content of natural U: 0.711%
- Enrichment tails assay: 0.3%
- Fresh fuel enrichment: 4.5%
- Losses are neglected
- Burnup: 50 MWD/kgHM
- Capacity factor: 0.9
- Thermal efficiency: 0.33

The Separative work per unit of enriched product can be obtained as:[28]

$$\frac{\text{kg SWU}}{\text{kg product}} = (2x_p - 1) \cdot \ln\left(\frac{x_p}{1 - x_p}\right) + \frac{x_p - x_{nat}}{x_{nat} - x_t} \cdot (2x_t - 1) \cdot \ln\left(\frac{x_t}{1 - x_t}\right) - \frac{x_p - x_t}{x_{nat} - x_t} \cdot (2x_{nat} - 1) \cdot \ln\left(\frac{x_{nat}}{1 - x_{nat}}\right)$$

where:
x_p = product enrichment
x_{nat} = natural enrichment
x_t = tails assay

Using the values presented above for x_p, x_{nat}, and x_t, we get 6.23 kg SWU/kg product.[29]

The fuel cycle cost can now be calculated (for 1 kgIHM of fresh UOX fuel):

Table A-5.D.1 Once-through UOX Fuel Cycle Cost

	M_i	C_i	ΔT_i (yr)	DIRECT COST $M_i \cdot C_i$ ($)	CARRYING CHARGE $M_i \cdot C_i \cdot \phi \cdot \Delta T_i$ ($)
Ore purchase	10.2 kg	30 $/kg	4.25	307	130
Conversion	10.2 kg	8 $/kg	4.25	82	35
Enrichment	6.23 kg SWU	100 $/kg SWU	3.25	623	202
Fabrication	1 kgIHM	275 $/kgIHM	2.75	275	76
Storage and disposal	1 kgIHM	400 $/kgIHM[30, a]	~2.25	400	-90
			Total	1686	353
			Grand Total	2040	

a. The cost of waste storage and disposal is assumed to be paid at the end of irradiation, even though the unit cost of $400/kgIHM is a proxy for the 1 mill/kWehr paid by utilities during irradiation.

The calculations are based on the following assumptions:

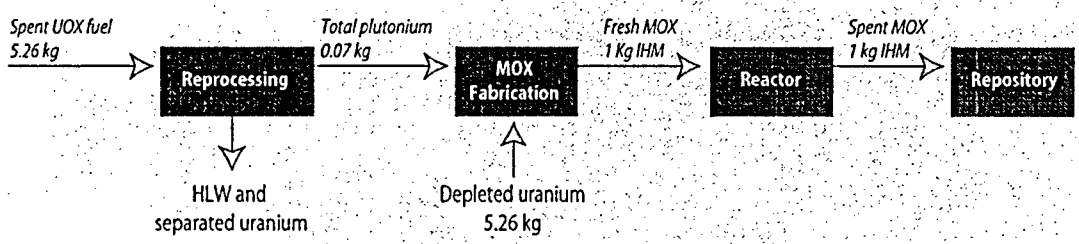
- Fuel irradiation time : 4.5 years
- Lead times:
  - 2 years for ore purchase
  - 2 years for conversion
  - 1 year for enrichment
  - 0.5 year for fuel fabrication
- Carrying charge factor: $\phi = 0.1$ per year.

The cost is thus $2,040/kgIHM. We can obtain the fuel cycle cost in ¢/kWh(e) as follows:

$$\frac{kgIHM}{0MWd} \cdot \frac{1MW}{1000kW} \cdot \frac{1d}{24h} \cdot \frac{1kW}{0.33kW(e)} = 5.15 \cdot 10^{-3} \frac{\$}{kWh(e)}$$

The fuel cycle cost is therefore 0.515 ¢/kWh(e).

MOX cycle — The MOX cycle can be represented as follows (for 1 kgIHM of fuel):



Assumptions

- Pu content of spent UOX 1.33%
- Pu content of fresh MOX: 7%
- Losses are neglected
- Burnup: 50 MWD/kgIGM
- Capacity factor: 0.9
- Thermal efficiency: 0.33

We now calculate the fuel cycle cost (per kgIHM fresh MOX fuel):

Table A-5.D.2 Single Recycle MOX Fuel Cycle Cost

	M_i (kgIHM)	C_i ($/kgIHM)	ΔT_i(yr)	DIRECT COST $M_i \cdot C_i$ ($)	CARRYING CHARGE $M_i \cdot C_i \cdot \phi \cdot \Delta T_i$ ($)
Credit for UOX SF	5.26	−400	4.25	−2105	−895
Reprocessing	5.26	1000	4.25	5263	2237
HLW storage and disposal	5.26	300	3.25	1579	513
MOX Fabrication	1	1500	3.25	1500	488
MOX Storage and disposal	1	400	−2.25	400	−90
			Total	6637	2253
			Grand Total	8890	

Assumptions

- Fuel irradiation time : 4.5 years
- Lead times:
  - 2 years for acceptance of spent UOX fuel,
  - 2 years for reprocessing,
  - 1 year for storage of HLW from reprocessing;
  - 1 year for MOX fuel fabrication
- The cost of acquiring depleted uranium is neglected

- Both the cost of separated uranium storage and the potential value of separated uranium material are not included in the analysis. Under current conditions, separated uranium is not used for fuel fabrication because using natural uranium is less expensive. Separated uranium is simply stored for possible use in the future. Since cost of storing separated uranium is very modest due to its low radioactivity, we ignore it in this analysis.
- The cost of HLW storage and disposal is assumed to be 25% lower than the cost of spent fuel storage and disposal. The HLW contains most of the fission products (including Sr-90 and Cs-137) and all the minor actinides present in the processed spent fuel, hence storage and disposal requirements are not expected to be much improved compared to spent fuel. However, because HLW has a lower volume and very small plutonium content, modest savings can be expected.
- The cost of storage and disposal for spent MOX fuel is assumed to be the same as for spent UOX fuel. Indeed, spent MOX is not reprocessed due to the degraded isotopic composition of its plutonium. We therefore consider it to be a liability comparable to spent UOX fuel.
- $\phi = 0.1$ per year

The fuel cycle cost is therefore $8,890/kgHM, or 2.24 ¢/kWh(e). This is approximately 4.5 times higher than for the once-through UOX cycle under U.S. conditions.

The incremental MOX fuel cost compared to UOX fuel cost will contribute to an increase in the cost of electricity in proportion to the ratio of MOX to UOX fuel in the entire fleet. Accordingly the incremental electricity cost for the fleet will be:

$$0.515 \text{ cents/kWe-hr } (1260/1500) + 2.24 \text{ cents/kWe-hr}(240/1500) = 0.791 \text{ cents/kWe-hr}$$

or a blended increase in the cost of electricity of 0.28 cents/kWe-hr in the MOX/UOX cycle compared to the once through UOX cycle.[31]

CONDITIONS FOR COMPETITIVENESS OF THE MOX OPTION

It is important to determine under what conditions the MOX fuel cycle becomes cost competitive with the once through UOX cycle. Cost components to consider are: (1) cost of natural uranium, (2) cost of reprocessing, (3) cost of MOX fabrication, and (4) cost of waste storage and disposal. Table A-5.D.3 presents the value that would make the fuel cycle cost of both options equal (breakeven value) for each of these four cost parameters.

Table A-5.D.3 Breakeven Values

COST COMPONENT	ORIGINAL VALUE	REQUIRED VALUE	REQUIRED/ORIGINAL
Natural uranium	$30/kgU	$560/kgU	19
Reprocessing	$1,000/kgIHM	$90/kgIHM	0.09
MOX fabrication	$1,500/kgIHM	Impossible	N/A
Waste storage and disposal	$400/kgIHM (SF)	$1,130/kgIHM	2.8
	$300/kgIHM (HLW)	$100/kgIHM	0.33

The cost of natural uranium is not likely to reach such high levels in the foreseeable future. The cost of reprocessing will probably never drop down to the required value of $90/kgHM. As for waste storage and disposal, it is not reasonable to expect that the cost will be 11 times higher for UOX and MOX spent fuel than for HLW from reprocessing; indeed, although the volume of the HLW is much smaller, it still contains most of the fission products and all the minor actinides from the spent fuel. Therefore, its heat load in the first few hundred years should be comparable to that of spent fuel. It can also be observed from Table A-5.D.2 that, even if we assume that HLW storage and disposal can be done at zero cost, the total cost of the MOX option is still $6798/kgIHM (obtained by subtracting the cost of HLW disposal, $1579+$513, from the total cost, $8890). This is equivalent to 1.72 ¢/kWh(e), or more than 3 times the cost of the once-through option. It should be noted, however, that the original values selected for the costs of waste storage and disposal are not an absolute reference: important differences exist between countries because this cost depends on how difficult the nuclear waste problem is perceived to be. For some countries, the cost of waste disposal may very well be much higher than the reference values used here.

Finally, we consider the effect of changing our cost assumptions for ore purchase, reprocessing, MOX fabrication, and waste storage and disposal simultaneously. We find that the fuel cycle cost of the two options is equal under the following revised assumptions:

Table A-5.D.4 Breakeven Values (components adjusted simultaneously)

COST COMPONENT	UNIT	ORIGINAL VALUE	REQUIRED VALUE
Ore purchase	$/kg	30	50
Reprocessing	$/kgIHM	1,000	600
MOX fabrication	$/kgIHM	1,500	1,100
Storage and disposal:			
Spent Fuel	$/kgIHM	400	600
HLW	$/kgIHM	300	100
Fuel cycle cost (both options)		6.3 mills/kWh	

Table A-5.D.4 shows that, by revising several cost assumptions in favor of plutonium recycling, we obtain equal fuel cycle costs for both options. Although the required ore purchase price is high and costs for reprocessing, MOX fabrication, and HLW disposal can be characterized as optimistic, they fall within the range of uncertainty defined by other fuel cycle cost studies (see Table A-5.D.6).

COMPARISON WITH OTHER ESTIMATES

There have been a number of studies on the economics of reprocessing with significant differences in assumptions. The most comprehensive study has been carried out by the OECD/NEA.[32] This study thoroughly evaluated the cost of the once-through and plutonium recycling fuel cycles, and concluded that the cost of the once-through option is about 15% lower (based on the assumptions presented in Table A-5.D.5). Thus, the findings of the OECD differ significantly from the result presented earlier, where the cost of the once-through option was found to be about 4 times lower.

There are several differences between the methodology used in the OECD study and the simple fuel cycle cost model used in this appendix. The OECD model is more detailed and the methodology for dealing with carrying charges is more involved. In addition, it sometimes uses different assumptions about the workings of the fuel cycles. For example, a credit is given for the irradiated uranium recovered in reprocessing, implying that it is used for fuel fabrication. In spite of such differences, assumptions regarding unit costs remain the dominant factor influencing fuel cycle cost estimates. The OECD study uses costs that are much more favorable to the reprocessing option. In fact, using the OECD assumptions in our model results in nearly equal costs for both fuel cycles. This is shown in Table A-5.D.5.

Table A-5.D.5 Fuel Cycle Cost Using OECD Estimates

COST COMPONENT	OECD ESTIMATE
Ore Purchase	50 $/kgHM
Conversion	8 $/kgHM
Enrichment	110 $/kg SWU
UOX fabrication	275 $/kgHM
SF storage and disposal	570 $/kgHM
Reprocessing	620 $/kgHM
HLW storage and disposal	60 $/kgHM
MOX fabrication	1,100 $/kgHM
FUEL CYCLE COST	
Once-through:	6.43 mills/kWh
MOX option:	6.80 mills/kWh

Table A-5.D.5 shows that OECD unit costs for the various back-end operations diverge significantly from the ones that were assumed in Tables A-5.D.1 and A-5.D.2. Such differences can be expected, as fuel cycle cost studies generally show very large uncertainties on such estimates. Indeed, few data on the cost of reprocessing and recycling operations are publicly available, and spent fuel or HLW disposal has not been implemented anywhere in the world, so the costs associated with these operations cannot be determined precisely. Furthermore, estimates are difficult to make for several reasons. First, engineering cost estimates for this type of activity are notoriously uncertain. Second, since fuel cycle facilities are high capital cost plants, the cost of capital assumption is very important.[33] Third, the cost estimates per unit product depend on assumption about both plant productivity and on allocation of fixed construction and development costs to unit output. Finally, the ultimate disposal cost for either spent fuel or HLW is not established. Certainly little confidence can be placed in any estimate on the *difference* in disposal costs for HLW and spent fuel.

Several other studies provide estimates of the unit costs for various fuel cycle operations. The OECD/NEA provides revised estimates in a recent study on advanced fuel cycles.[34] The Gen-IV Fuel Cycle Crosscut Group offers a range of estimates in its report.[35] Fetter, Bunn, and Holdren have offered an analysis of the economics of reprocessing versus direct disposal of spent nuclear fuel.[36] Finally, the National Research Council's study on Nuclear Waste[37] has an appendix on recycling economics. Note that the unit costs presented in these studies implicitly carry three charges: the direct cost of the activity, a capital charge that depends upon the assumed rate of return, and a capital charge for the "work in progress," i.e. the hold-up time for material flow through the system (for example, if it takes two years or three years of plutonium inventory to maintain a given material flow at

a reprocessing plant, this influences the cost of reprocessing). We include in Table A-5.D.6 our "best guess" for the value of the parameters but stress, in the strongest possible terms, as can be seen from the difference in estimates made by other studies, the tremendous uncertainty in these numbers.

Table A-5.D.6 Comparison of Cost for Once-through and Recycle Process Steps

		ESTIMATED COST (lower bound - nominal - upper bound)			
COST COMPONENT	UNIT	OECD/NEA[34] (2002)	DOEGEN-IV[35]	Fetter, Bunn, Holdren[36]	Our Best Guess
Ore Purchase	$/kg	20-30-40	20-30-80	33	30
Conversion	$/kg	3-5-7	3-5-8	4-6-8	8
Enrichment	$/kg SWU	50-80-110	50-80-120	50-100-150	100
UOX fabrication	$/kgIHM	200-250-300	200-250-350	150-250-350	275
SF storage and disposal	$/kgIHM	410-530-650	210-410-640	0-150-300 (more than HLW)	400
UOX reprocessing	$/kgIHM	700-800-900	500-800-1,100	500-1000-1600	1,000
MOX reprocessing	$/kgIHM	700-800-900	500-800-1,100	—	—
HLW storage and disposal	$/kgIHM	63-72-81	80-200-310	0-150-300 (less than SF)	300
MOX fabrication	$/kgIHM	900-1,100-1,300	600-1,100-1,750	700-1,500-2,300	1,500

CONCLUSION

The simple fuel cycle cost model shows that the MOX option is roughly 4 times more expensive than once-through UOX, using estimated costs under U.S. conditions. Thermal recycle can be shown to be competitive with the once-through option only if the price of uranium is high and if optimistic assumptions are made regarding the cost of reprocessing, MOX fabrication, and HLW disposal.

The case is often advanced that disposing of reprocessed high level waste will be less expensive than disposing of spent fuel directly. But there can be little confidence today in any estimate of such cost savings, especially if disposal of TRU waste associated with thermal recycle facilities and operations is taken into account. Furthermore, our cost model shows that even if the cost of disposing of reprocessed high-level waste were zero, the basic conclusion that reprocessing is uneconomic would not change.

It should be noted that the cost increment associated with reprocessing and thermal recycle is small relative to the total cost of nuclear electricity generation. In addition, the uncertainty in any estimate of fuel cycle costs is extremely large.

Appendix 5.E — Price and Availability of Uranium

URANIUM RESOURCES AND RESERVES

The most authoritative source for estimates of uranium resources is the OECD/IAEA Red Book.[38] Figures from the latest edition are shown in Table 1.

Table A-5.E.1 OECD Conventional Uranium Resources (million metric tons, as of January 2001)

KNOWN CONVENTIONAL RESOURCES COST RANGES			REPORTED UNDISCOVERED CONVENTIONAL RESOURCES COST RANGES	
<40$/kgU	40 – 80$/kgU	80 – 130$/kg	<130$/kgU	Cost Range Unassigned
2.1	1.0	0.8	6.8	5.5
Total Uranium Resources: 16.2				

The term "reserves" refers to the known conventional resources that can be extracted using current technology under current economic conditions at various recovery costs. For example, from Table 1, reserves recoverable at costs = $40/kgU amount to about 2 million metric tons of uranium (MTU), enough for about 30 years at the current consumption rate.[39] However, reserves are only a small fraction of the total uranium resource base, which also includes known deposits that are not economic to recover at present prices or are surmised to exist with varying degrees of uncertainty in the vicinity of well-mapped deposits or by similarity of one unexplored geologic structure to other mapped and productive ones. When uranium prices rise, presently uneconomic resources will become economic to recover and mining companies will also have an incentive to delineate presently unmapped resources. As a result, new reserves will be created that can be used to fuel a growing installed nuclear capacity.

A quantitative example of the increased reserves that would be created as a result of higher prices has been given by the Uranium Information Centre in Australia: a doubling of the uranium price – which has been declining steadily since the late 1970s; see Figure 1 – from present contract levels could be expected to create about a tenfold increase in measured resources.[40] The term "measured resources" in this context refers to reserves extractable at costs = $80/kgU, which from Table 1 amount to about 3 million MTU. Thus, a doubling of uranium prices from about $30/kgU to $60/kgU could be expected to increase these reserves to approximately 30 million MTU. This can be compared with the requirements of the following 1500 GWe mid century scenario: installed nuclear capacity grows linearly from the current 350 GWe to 1500 GWe over 50 years and, after this growth period, no new plants are built and existing ones are operated for the rest of their lifetimes. The total production over the growth period is 41,625 GWe•y (assuming a capacity factor of 0.9), requiring 9.5 million MTU (assuming a uranium consumption of 226.5 MTU/GWe•y). Nuclear capacity then begins to decline: the newest plants still have 50 years of production ahead of them, but the units built at the beginning of the growth period must be decommissioned. Assuming an average remaining life of 25 years for the fleet, total electricity production over the decline period is 33,750 GWe•y, requiring 7.5 million MTU. The total uranium consumption for this scenario is therefore 17 million MTU. The 30 million MTU

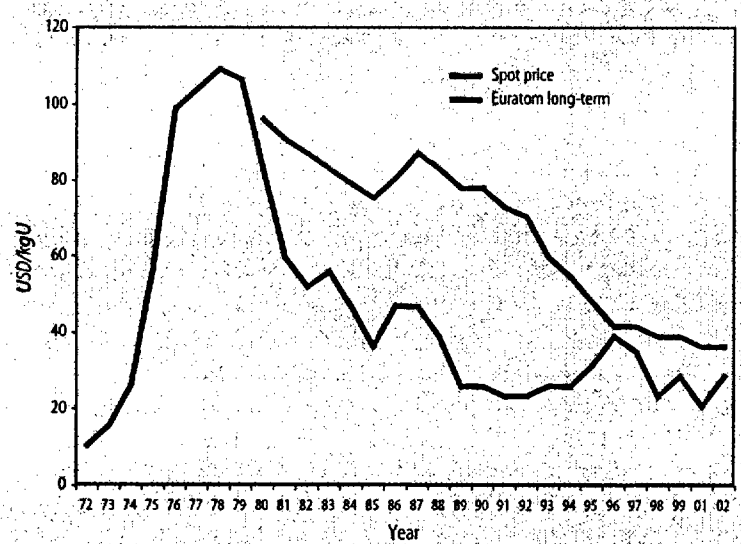
of reserves available if the uranium price doubled are more than sufficient to support this scenario.

INCREASED RESERVES FROM HIGH AND LOW GRADE ORES

The increase of reserves as a result of higher uranium prices could come from both high and low grade ores. The former are the "unconformity-related" deposits discovered starting in the late 1960s in Australia and Canada where typical ore concentrations exceed 10%. The world's largest, highest grade uranium mine at McArthur River in Saskatchewan, Canada is of this type. Estimates of reserves at McArthur River increased by more than 50% in 2001,[41] and further increases in reserves can be expected as a result of further exploration at this mine and other unconformity-related deposits. But such exploration followed by increased production is unlikely at today's uranium prices. Indeed, according to Bernard Michel, the former CEO of Cameco Corp., the McArthur River mine operator, uranium's current low price is "unsustainable".[42]

Most of the terrestrial uranium resource consists of large quantities of low grade ore. For example, phosphate deposits, which typically carry 10 to 300 parts per million of uranium, are believed to hold 22 million tons of uranium. A 1980 Scientific American article[43] suggests that the distribution of uranium resources as a function of ore grade is such that, in the region of current commercial interest, a reduction in ore grade by a factor of 10 increases the amount of available uranium by a factor of 300. Equivalently, for a decrease in ore grade by a factor of 2, uranium resources expand by a factor of 5.

Figure A-5.E.1 Uranium Prices, 1972–2001
annual basis



INCREASED URANIUM PRICES AND THE COMPETITIVENESS OF NUCLEAR ELECTRICITY

Table 2 shows that an increase in the price of uranium ore from 30$/kg to 60$/kg corresponds to an increase in ore price of about 1.10 mills/kWh. This corresponds to a modest increase of 2.2% in the cost of nuclear electricity.

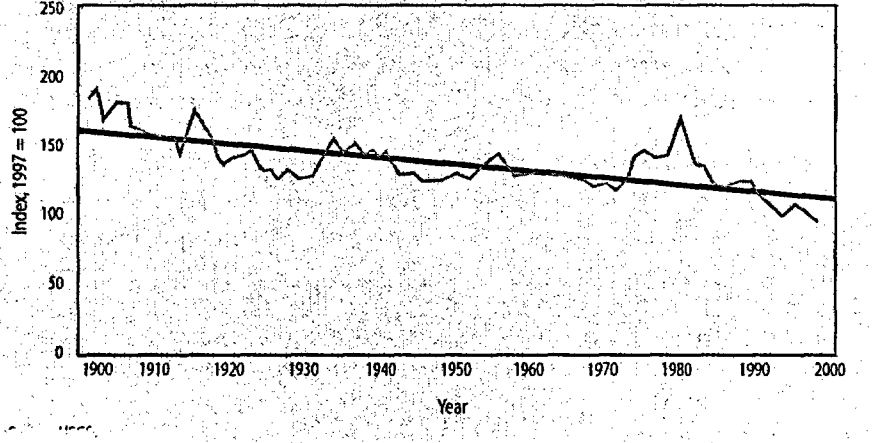
Table A-5.E.2 Cost of Uranium Ore as a Fraction of Cost of Electricity

	ORE PRICE (mills/kWh)			
ORE PRICE ($/kg)	Direct cost[a]	Carrying charge[b]	Total	% BUSBAR COST[c]
30	0.78	0.33	1.11	2.2%
50	1.29	0.55	1.84	3.7%
60	1.55	0.66	2.21	4.4%
100	2.59	1.10	3.68	7.4%
130	3.36	1.43	4.79	9.6%
200	5.17	2.20	7.37	14.7%

a. Assuming uranium consumption of 226.5 kg/MWey for LWRs.
b. Assuming a lead time of 4.25 years and a carrying charge factor of 0.1
c. Assuming busbar cost of 50 mills/kWh, or 5 ¢/kWh.

Furthermore, even if uranium prices increase as the most attractive deposits are depleted, there is good reason to expect that prices will not soar to prohibitively high levels. Historical data show that, over the past century, advances in exploration and extraction technologies have made it possible to recover lower grades and other less attractive resources at constant or even decreasing costs in constant dollars. The U.S. Geological Survey[44] provides data showing that the U.S. mine production composite price index has decreased throughout the 20th century, even as consumption of minerals increased significantly (see Figure 2). The USGS observes that advances in technology have been more than sufficient to overcome obstacles to supply. The USGS also provides striking data on the price and production levels of 4 selected commodities over the 20th century (see Table 3).

Figure A-5.E.2 Composite mineral price index for 12 selected minerals, 1900 to 1998, in constant 1997 dollars. Selected mineral commodities include 5 metals (copper, gold, iron ore, lead, and zinc) and seven industrial mineral commodities (cement, clay, crushed stone, lime, phosphate rock, salt, and sand and gravel).



Although uranium is different from other extractive resources because of its national security implications, we do not believe that this fact changes the fundamental process by which higher prices not only lead to exploration efforts but also create an incentive to innovate, which leads to technological progress and tends to hold prices down.

Table A-5.E.3 20th Century World Production and Price for 4 Selected Commodities

COMMODITY	PERIOD	INCREASE IN PRODUCTION (percent)	DECREASE IN CONSTANT DOLLAR PRICE (percent)
Aluminum	1900–1998	3,250	89.7
Copper	1900–1998	2,465	75.0
Potash	1919–1998	3,770	93.9
Sulfur	1907–1998	6,000	89.4

NOTES

1. By "real" we mean that all cash flows are expressed in constant dollars that have been adjusted for the effects of general inflation over the life of the project. However, the cash flows themselves must first be calculated using nominal dollars (including inflation) in order to properly calculate income tax obligations since tax depreciation is based on nominal construction costs and nominal interest payments are a tax deductible expense.
2. Taxable income may be reduced by allowing carry forward of net operating losses, most likely in early years of operation where both interest payments and tax depreciation allowances are substantial.
3. The model can be readily adapted to allow real prices for electricity to grow at a constant rate over time, but this complicates somewhat comparison of alternative technologies.
4. Energy Information Administration, *Annual Energy Outlook 2003 With Projections to 2025*, DOE/EIA-0383(2003), January 2003.
5. U.S. Department of Energy Office of Nuclear Energy, Science and Technology, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010*, October, 2001.
6. *Nuclear Energy Agency / International Energy Agency, Projected Costs of Generating Electricity*, Update 1998.
7. Tarjanne, Risto and Rissanen, Sauli, *Nuclear Power: Least-Cost Option for Baseload Electricity in Finland*, The Uranium Institute 25th Annual Symposium, 2000.
8. The exchange rate between euros (EUR) and U.S. dollars (USD) has fluctuated between 0.85 and 1.18 EUR / USD over the past two years. For our purposes, a central value of 1 EUR / USD is acceptable.
9. UK Performance and Innovation Unit, *The Economics of Nuclear Power: PIU Energy Review Working Paper*, 2001.
10. International Energy Agency, *Nuclear Power in the OECD*, 2001.
11. Tennessee Valley Authority, *Final Supplemental Environmental Impact Statement for Browns Ferry Nuclear Plant Operating License Renewal*, March, 2002.
12. Williams Capital Group Equity Research, July 2001.
13. The TVA Act requires TVA to compensate state and local governments with tax equivalent payments.
14. In the case of South Korea, the exchange rate between Korean won (KRW) and U.S. dollars (USD) ranged from 800 to 1,800 KRW / USD during the construction phase of the recent nuclear project.
15. OECD, *Purchasing Power Parities and Real Expenditures: 1999 Benchmark Year*, 2002.
16. The currency exchange rate was 119 yen / U.S. dollar on May 28, 2003.
17. Construction costs for Yonggwang Units 5 and 6 were obtained through personal communication with Professor Soon Heung Chang of Korea Advanced Institute of Science and Technology (KAIST).
18. The currency exchange rate was 1,200 won / USD on May 28, 2003.
19. *Energy Information Administration, Electric Power Annual 2001*, DOE/EIA-0348(01), March 2003.
20. *Energy Information Administration, An Analysis of Nuclear Power Plant Operating Costs: A 1995 Update*, SR/OIAF/95-01, April 1995.
21. Energy Information Administration (EIA), 1995.

22. Ibid.

23. Statistics reported by NEI were extracted from the February 2002 NEI Annual Briefing for the Financial Community, "Nuclear Energy 2002: Solid Value... Significant Upside"

24. Energy Information Administration, *Assumptions for the Annual Energy Outlook 2003*, DOE/EIA-0554 (2003), January 2003.

25. U.S. Department of Energy Office of Nuclear Energy, Science and Technology, *A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010*, October, 2001.

26. Note that T_i can vary depending on the fuel management strategy

27. The unit used for mass of nuclear fuel the "kilogram of initial heavy metal", denoted kgIHM. We always refer to the initial mass of heavy metal in the fuel because the heavy metal atoms are fissioned as the fuel is irradiated, and therefore their mass decreases with time.

28. See, for example, Tsoulfanidis and Cochran, "The Nuclear Fuel Cycle", ANS, 1999, p. 62.

29. Alternatively, a simple linear relationship can be used to approximate the SWU requirement. For a tails assay of 0.3%, the following holds:

$$\frac{\text{kg SWU}}{\text{kg product}} = 2.07 \cdot x_p - 3.23$$

Using the same values as above for x_p, x_{nat}, and x_t, we get 6.09 kg SWU/kg product.

30. This value corresponds to the fee of 1 mill per kilowatt-hour of nuclear electricity generated paid to the DOE by each utility operating a nuclear power plant:

$$\frac{0.001\$}{kWh(e)} \cdot \frac{0.33kWh(e)}{1kWh} \cdot \frac{24h}{1d} \cdot \frac{1000kW}{1MW} \cdot \frac{50MWd}{1kg1HM} \approx 400 \frac{\$}{kgIHM}$$

31. We thank Matt Bunn for reminding us of the effect of increased MOX cost on blended electricity cost.

32. OECD/NEA "The Economics of the nuclear fuel cycle," 1994.

33. For example, the NRC study (footnote 7) estimates the levelized reprocessing cost for a 900 MTHM /year plant varies for different owner operators as follows: government $800/kgHM, utility $1300/kgHM, private venture $2000/kgHM.

34. OECD/NEA, "Accelerator-driven Systems and Fast Reactors in Advanced Nuclear Fuel Cycles", 2002

35. DOE, "Generation 4 Roadmap - Report of the Fuel Cycle Crosscut Group", 2001

36. Fetter, Bunn, Holdren, "The Economics of Reprocessing vs. Direct Disposal of Spent Nuclear Fuel", 1999

37. "Nuclear Waste – Technologies for separations and transmutation," Committee on Separation Technology and Transmutation systems, National Research Council, National Academy of Sciences, Appendix J, 1996

38. OECD/NEA & IAEA, "Uranium 2001: Resources, Production, and Demand", 2002

39. Current light water reactors consume approximately 226.5 MTU/GWe-y of electricity generated, hence the demand for today's fleet of 350 GWe is approximately 70,000 MTU per year, assuming a capacity factor of 90%.

40. Uranium Information Center, "Nuclear Electricity", 6th edition, Chapter 3 (2000). Available on the web at http:www.uic.com.au/ne3.htm.

41. See www.cameco.com/investor/news_releases/2001-jan-25.html.

42. R. Martin, "Nuclear Rock", Time Magazine, Feb. 16th, 2003.

43. K.S. Deffeyes and I.D. MacGregor, "World Uranium Resources", Scientific American, Vol. 242, No.1, Jan. 1980.

44. David Wilburn, Thomas Goonan, Donald Bleiwas, Eric Rodenburg, "Technological Advancement – A Factor in Increasing Resource Use", U.S. Geological Survey, 2001.