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Agenda

Advancing economics in business

Financing the nuclear option: modelling the costs of new build

In light of the current debate surrounding the future of electricity generation in the UK, Oxera has developed an investment model to determine the conditions under which private investors could finance a new fleet of nuclear power stations

UK electricity generation has arrived at a crossroads. Without new investment, almost 14GW of generating capacity will be lost by 2020: 8GW due to the decommissioning of Magnox and advanced gas-cooled reactor stations, and possibly another 6GW as a result of retiring ageing coal plants.[1] Just over two years ago, the simultaneous maximum load met by the industry was already at 88% of the total declared capacity, up by around 10% in a decade.[2] This indicates the necessity for new capacity, and the continued addition of new plants as ageing plants retire. If the new plants are standard combined-cycle gas turbine (CCGT) power stations, the consequence will be greater dependence on gas supplies and higher CO_2 emissions. A choice has to be made about what type of new plant will be built.

Beyond the issue of capacity, climate change has become the critical factor for the future of energy policy, in line with the government's target in the 2003 Energy White Paper of a reduction in greenhouse gas emissions by 60% by 2050.[3] The problem of CO_2, combined with concerns about security of supply and sharply rising oil and gas prices, has given rise to the consideration of renewables and nuclear new build (alongside programmes of energy efficiency and carbon sequestration) as potential alternatives to the 'default' scenario of investments in CCGTs. CCGTs have been perceived as offering the highest potential return and are likely to remain the benchmark for any new build; however, the alternatives benefit from no CO_2 emissions. Given the estimated public cost of carbon of £85/tonne[4] (versus the private cost of zero), a case can be put forward for remedying market failure by reversing the negative externality of greenhouse gases with explicit support for non-CO_2 generators. The EU Emissions Trading Scheme (ETS) was designed to address this issue but may internalise the externality only partially, given expectations that prices of EU ETS allowances will be below the social cost.[5]

An investment programme in new build?

In this context, it is useful to consider the economic viability of private sector investment in generation capacity beyond fossil fuels, without any government support. Estimating the economic viability of a hypothetical investment in the 'base case', or the most likely 'pure market' scenario, will allow for the subsequent analysis of different options involving limited public support, ranked by their expected social benefits that might justify government intervention. Closely related to this is the issue of price in terms of potential public funds necessary to attract private investors to such alternatives. Much of the discussion of these issues has thus far concentrated on renewables.[6] The Energy White Paper, on the other hand, stipulates the policy of leaving the nuclear option 'open' rather than explicitly addressing it, which has arguably relegated any potential programme of nuclear new build to a dormant state; indeed, the most recent energy review took the view that, at current prices, nuclear new build is uneconomical.[7] Given recent market developments, and ahead of any future energy policy, this article identifies the conditions under which the private sector might be able to finance a new fleet of nuclear power plants, should the government decide to pursue this course of action.

Any new investment must meet the necessary hurdle of sufficient expected equity return to compensate investors for the risks they will assume. This means that the key risks must be identified and translated into appropriate costs of financing for the purposes of a financial analysis of the hypothetical investment. These costs must be combined with prevailing market conditions, as well as realistic price projections, in order to arrive at valid conclusions. In the case of nuclear new build, this raises a number of questions: what wholesale electricity prices might new build be able to realise for many decades to come? What are reasonable assumptions about the cost of capital and financing structures? How sensitive would these be to changing market circumstances? What impact might the EU ETS and other government policies have on final returns?

Oxera's analysis of a hypothetical investment programme in a set of new nuclear stations (broadly equivalent to the proposed investment in renewables), which would restore the current share of nuclear generation by 2025, attempts to answer these and related questions. In 2003, the generating potential of the entire existing UK nuclear sector was 12GW, meeting around 22% of the UK's total electricity needs.[8] Over three-quarters of this installed capacity remains in the hands of British Energy; the remainder, largely represented by the ageing Magnox stations and operated as a subsidiary of BNFL, is on the path to being progressively shut down. This process should be complete by 2010—the deadline set by the 2002 White Paper on the nuclear legacy.[9] As a result, by 2020, the nuclear sector's share of total UK electricity generation is likely to fall by around 8GW, or to 7%, taking into account the estimated 1% annual growth in electricity consumption.

According to industry sources,[10] it takes at least four years for any reactor to be built and made operational. Taking into account the likely length of the preceding public inquiry, as well as the time required to obtain all regulatory approvals, it is difficult to imagine how the first of any new reactors could be made operational before 2015. Given a reasonable assumption that no more than one reactor unit could then be added every 18 months, and assuming that a fleet of new reactors were developed, two units could be added every three years until 2024 according to the most optimistic development scenario. A plan to restore the current share of nuclear power generation by 2025 would therefore be most likely to involve the construction of four pairs of 2GW generating plants, each with large, identical 1GW reactor units. The expected total funding required for this programme would be approximately £8.6 billion (2005 prices), to be spent by 2024, inclusive of all related costs but excluding the costs of insurance or any potential guarantees.

Before any financing considerations can be assessed, the critical hurdle for any new build remains that of nuclear waste and decommissioning plant at the end of its useful life. Although current decommissioning costs are high, these programmes concern legacy sites typically developed with little regard for dismantling, de-fuelling, or waste disposal. In contrast, new designs explicitly incorporate decommissioning plans. Nevertheless, fundamental questions about the national plan for nuclear waste disposal remain unresolved, and political decisions regarding this issue are needed before any progress can be made. Assuming that these questions can be addressed, a realistic estimate of decommissioning costs in net present value (NPV) terms could reach up to £1 billion in nominal terms per single station with two 1GW reactors, with the assumption of a useful life of 40 years.[11]

Can future prices support nuclear projects?

Aside from questions about policy on waste, the most important risks investors might face concern revenues over the length of plants' useful lives. With high up-front, fixed costs, nuclear power plants may be particularly exposed to market price fluctuations and uncertainties of projecting electricity prices over 60 years.[12] Oxera's model of the UK electricity market suggests that the long-term, 'average' real wholesale price could vary between £20/MWh and £40/MWh beyond 2012, implying the central real price scenario of around £30/MWh.[13] This price reflects the wholesale gas price of 28p/therm and the EU ETS allowance price of €20/tCO_2 with no grandfathering.[14] The effective price of electricity realised by British Energy was £21.3/MWh for the third quarter of 2004/05, although a new price of £25.2 was reportedly secured by British Energy for over 50% of the total output in the next fiscal year.[15] Although below current market prices, the mean price realised by British Energy has increased over the past four years, on average by approximately 8.5% per year.[16] For comparison, in the analysed base case scenario, a constant real price of £30/MWh from 2012 would imply a nominal price of £33.8 in 2012 when converted at the inflation rate of 1.71%—the mean annual mark-up of nominal over real electricity prices over the past 35 years.[17]

Since nuclear generators can be assumed to be price-takers, they are set to benefit directly from the increase in prices caused by the introduction of the EU ETS. Given the falling net share of nuclear generation over the length of the hypothetical new build programme, and the limited scale of potential new build as a share of total generating capacity, there appear to be no grounds for assuming a negative feedback effect on wholesale electricity prices. In other words, nuclear economics is likely to be determined exogenously by developments in gas prices and potential government transfers.

Challenges of construction and financing nuclear new build

Beyond realised prices and revenues, development costs are likely to represent the second most important risk factor for any investment decision regarding new build. Large engineering projects, particularly construction of nuclear power stations, are typically characterised by a high degree of financial risk in their initial stages. Many examples, from the UK's Sizewell B plant to the Darlington plant in Canada, indicate that cost overruns and time delays are likely to have serious negative financial implications for the project, especially for those using first-of-its-kind design. Therefore, provisions have to be made for such cost overruns over contractors' estimates. Past records could imply as much as a mean 20% cost overrun on the first reactor, decreasing by 50% of the initial cost mark-up for each new reactor.[18] It is possible that a further £100m capital contingency for other costs relating to the first-of-its-kind aspect might need to be added to reflect special circumstances of building the first nuclear power station in the UK for decades. Finally, £100m could be the assumed cost of licensing and the public inquiry, plus £50m for development costs for each subsequent reactor.

On average, therefore, this could suggest total development costs of as much as £1.6 billion for the first reactor, decreasing to £1.15 billion for subsequent reactors, in 2005 prices. This would be similar to the overall cost of the only European ongoing new nuclear development at Olkiluoto, Finland, where Framatome, a division of AREVA, is building a 1.6GW station estimated to cost €3 billion—the equivalent of approximately £1.27 billion/GW.[19] In comparison, the new AP1000 reactor of 1GW capacity from Westinghouse has been estimated to cost less than £1.1 billion.[20] However, even a 30% contingency may not be sufficient for investors to assume construction and start-up risks. Given the size of investment, the market could fail in efficiently hedging these risks and government guarantees might be necessary before the station is operational.

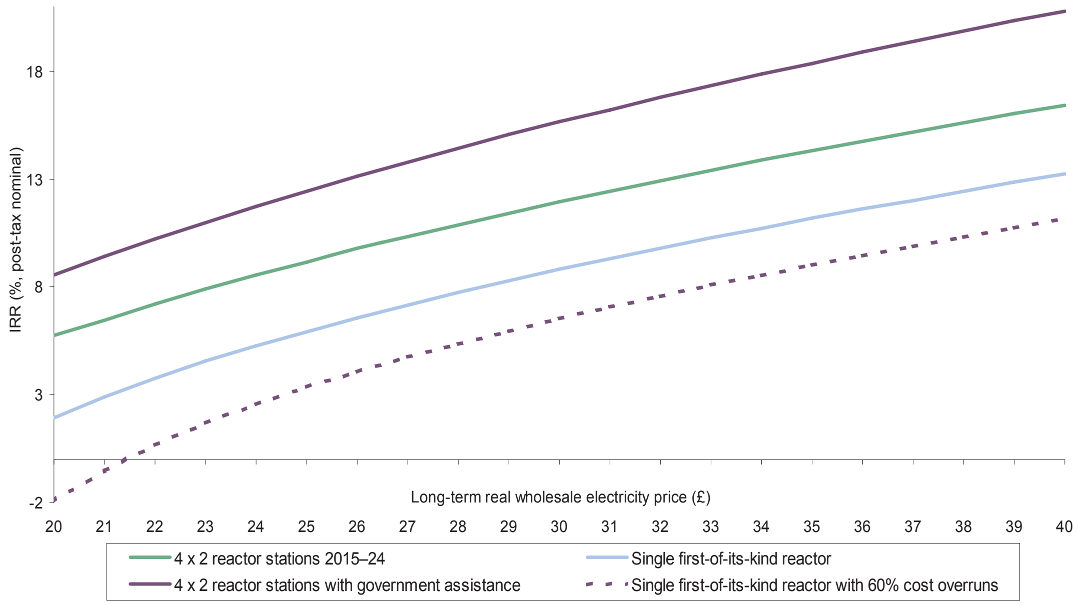
With maximum leverage of up to 70% (assuming no external debt guarantees), the entire programme could be financed with equity capital of approximately £3 billion, with 100% interest capitalisation over the construction period.[21] Following refinancing at the start of the operational phase, the debt as a proportion of the market value of the generating asset could then increase slowly over the duration of the project, with progressively greater principal repayments to match revenues with constant debt service. Under an alternative scenario, with no interest capitalisation over the construction period, leverage would decrease to 60% in the first year of operations, with equity contributions reaching over 50% of the total development cost, and the estimated interest coverage ratio increasing to 2.75 from 1.8 at its lowest level. In the absence of any guarantees, construction risks might also be reflected in the assumption of a significantly higher cost of debt during the construction phase. The latter could then be financed with a syndicated bridge loan or otherwise, to be refinanced at the estimated 7–8% rate for the project on a stand-alone basis, as each plant becomes operational.[22] Table 1 summarises the key assumptions.

Table 1 Key assumptions for the base case scenario

Construction cost for first plant (including contingency, licensing, start-up, and public inquiry, £m/MW)	1.625
Electricity prices inflation (= 1.71% retail average 1970–2004, %)	1.71
Real prices 2012 onwards (£/MWh)	30
Contingency provisions: the first reactor (%)	30
Tax rate (%)	30.0
Guaranteed debt interest rate (%)	5.0
Interest rate during development/construction (%)	10.0
Interest rate during operating phase (after refinancing, %)	7.5
Interest capitalisation during construction phase (%)	50.0
Construction cost inflation (%)	1.5
Developer's equity (£m)	600
Decommissioning fund investment rate (%)	4.0
Decommissioning fund target end of year 40 (£m)	500
Admin and other costs per year (£m)	15
Fuel costs per kWh (£)	0.0030
Maintenance costs per kWh (£)	0.0035
Maintenance hours (% total per annum).	5.0
Capacity (GW)	1
Load factor (%)	95.0
CAPEX for years 20 and 30 (£m)	50
Cost inflation per year (%)	2.0

Under the base case scenario with the real wholesale prices in the range of ±10% around the base case of £30/MWh (ie, £27–£33), Oxera's analysis estimates the nominal, after-tax internal rate of return (IRR) to equity of 8–11% for the first, single reactor to be built in the UK between 2011 and 2015 (or 6.3–9.7% with doubled cost overruns). For a fleet of eight reactors, completed in the period 2015–24, this range of nominal IRRs could rise to 10.6–13.6%, with the last two reactors contributing IRRs above 15% on a stand-alone basis in the base case.[23] Figure 1 presents IRRs for a wider distribution of inputs. This indicates that, given the EU ETS and rising electricity prices, the new build is likely to be modestly profitable and could comfortably withstand a negative 10% real-price fluctuation in liquidity terms. In fact, a 33% drop in the long-term real price of electricity to

Figure 1 Nuclear new build: sensitivity analysis of equity returns



Source: Oxera calculations.

approximately £20/MWh would be necessary for the project to default on its debts—the price close to that realised by British Energy in 2004/05.

However, these predicted results are likely to prove insufficient to convince a private investor to accept the significant equity risk involved in the project. UK equities have averaged an annual capital return of 9.6% (excluding dividends) over the past 100 years, and analogous returns on electricity utilities have been between 7% and 12% over the past 15 years.[24] The expected return on equity from a nuclear generator on a stand-alone basis is likely to carry a risk premium (linked to technology, price sensitivity and cost overruns, as discussed above) of 200–400 basis points or more above the benchmark.[25] One-half of that might be attributable to the cost of equity for any generator, given liberalised electricity markets, and the other half to technological and construction risks. In effect, therefore, the cost of equity for this type of project could be in the range of 14–16% nominal return or more.

It is anticipated that a programme of public assistance beyond the EU ETS would be needed to boost predicted IRRs to a level that is acceptable to private investors, in addition to any potential guarantees over the construction period. Two basic avenues of applying public assistance that could be explored here involve debt guarantees and capital grants. For example, cumulative capital grants of £1.6 billion for the fleet of eight reactors would not only reduce the private equity requirement to £2.8 billion, but could boost the range of nominal IRRs to 14–17.5% for the price scenarios described above. That said, however, a programme of £3.2 billion of debt guarantees (£400m per reactor) could result in IRRs of 11.5–14.5%—an increase of over 1% and rising to more than 2% if the amount of guarantees is doubled.[26] In contrast, a delay in the start-up of operations could result in a fall of the cumulative IRR by 0.6–0.9% for every year of the delay. Also, beyond IRRs, other factors might pose problems for the new build. One such barrier is the sheer scale of the required investment, estimated to equal £4.4 billion of private equity capital for the hypothetical investment programme introduced above. Another is the cost of insurance at various levels of liability, where government assistance might be needed.

Conclusion

If the government were to decide that new nuclear power stations are to be built, it would probably require assurance that the market could deliver them unaided. The results of Oxera's modelling show that the potential investment in nuclear new build is likely to bring positive returns under a range of possible scenarios, inclusive of contingencies and development cost overruns, although it would still not be sufficient to give rise to the expectation that private investors would foot the bill without any public assistance. Market conditions are clearly more favourable to nuclear today than they were just a few years ago, but barriers remain, including significant risks that need to be managed or insured against if private capital is to be forthcoming. Nevertheless, Oxera's modelling analysis shows that the nuclear option is by no means closed, although economic investment is likely to require government support.

[1] Oxera estimates based on the current decommissioning plans from the Nuclear Decommissioning Authority and the Department of Trade and Industry (DTI).
[2] DTI (2004), 'UK Energy Sector Indicators, 2004'.
[3] DTI (2003), 'Our Energy Future: Creating a Low Carbon Economy', February.
[4] Based on Clarkson, R. and Deyes, K. (2002), 'Estimating the Social Cost of Carbon Emissions', Government Economic Service Working Paper 140, January: 'The most sophisticated of the published studies reviewed here produces an estimate of marginal damage figure of approximately £70/tC (2000 prices) for carbon emissions in 2000. This increases by approximately £1/tC per year in real terms for each subsequent year to account for the increasing damage costs over time.' Defra is currently in the process of preparing revised estimates.
[5] The price would be determined by supply and demand, given available permits. Supply is likely to be greater under grandfathering, so, indirectly, prices will be lower.
[6] See *Agenda* (2005), 'Plugging the Carbon Productivity Gap', April.
[7] DTI (2003), op. cit., p. 65.
[8] DTI (2004), op. cit. and Oxera calculations.
[9] DTI (2002), 'Managing the Nuclear Legacy: A Strategy for Action', July.
[10] See, for example, www.westinghousenuclear.com.
[11] It is assumed that, after 40 years, the net present value of the decommissioning fund on the last day of operations will need to reach £1 billion for a single station with two 1GW reactors. For some comparative estimates of decommissioning costs and related assumptions, see www.westinghouse.com; Scully Capital (2002), 'Business Case for New Nuclear Power Plants: Bringing Public and Private Resources Together for Nuclear', report prepared for the US Department of Energy, July; and Massachusetts Institute of Technology (2003), 'The Future of Nuclear Power: An Interdisciplinary MIT Study'.
[12] Without any plant-life extensions beyond 40 years, the last reactor of this hypothetical development programme would be decommissioned in 2064.
[13] This assumes that there is no long-term change in the real wholesale price of electricity beyond 2012.
[14] That is, it assumes that generators of CO_2 would need to purchase all EU ETS allowances on the open market.
[15] British Energy Group plc, investor presentation, February 14th 2005, http://www.british-energy.com/.
[16] If this trend were to continue, the realised nominal price would reach £39/MWh by 2012.
[17] See http://www.dti.gov.uk/energy/inform/energy_prices/tables for details.
[18] See, for example, Flyvbjerg, B., Bruzelius, N. and Rothengatter, W. (2003), *Megaprojects and Risk*, Cambridge University Press. This implies 10% contingency for the second reactor falling to 5% for the third reactor; twin reactors to be built per site.
[19] AREVA (2003), 'Olkiluoto 3: Un projet EPR clé en main en Finlande (European Pressurized Water Reactor)', press release, December.
[20] Westinghouse Electric Company, 'Westinghouse AP1000', www.westinghouse.com.
[21] Necessary capital contribution could be diminished further, potentially quite substantially, with government debt guarantees over the initial construction and start-up period or for the duration of the project.
[22] This analysis makes typical assumptions about the risk-free rate and the interest rate on government-guaranteed debt over the long term if this were to become available under different financing scenarios, in line with the current flat shape of the yield curve.
[23] If combined with a downturn in nominal revenues of 10%, the minimum IRR would be 9% (the cost of securing long-term contracts might be equal to 10% of revenues in nominal terms). However, the low-cost variability of nuclear generators might prove valuable with call options for delivery at high gas prices potentially sufficient to secure a significant degree of downside protection.
[24] As reported by Finfacts: http://www.finfacts.com/stockperf.htm; Oxera calculations from Datastream.
[25] Scully Capital (2002), op. cit., and industry estimates.
[26] In comparison, the Flex-funds Total Return Utility Fund has reported returns of over 15% for five out of ten years since 1995, two years of returns between 5% and 15%, and two years of negative returns; see www.flexfunds.com.