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Abstract

The risks and returns associated with different choices of electricity generation technology cannot properly be considered in isolation. The paper considers their impact on an investing company, using Mean-Variance Portfolio (MVP) theory to identify optimal generation portfolios in liberalised electricity markets characterised by fuel, CO_2, and electricity price risk. The paper demonstrates the importance of correlations between electricity, CO_2, and fuel prices, which explain the dominance of combined-cycle gas turbines. It questions whether the market can provide incentives for socially optimal fuel-mix diversification.

Keywords: fuel-mix, price risk, Mean-Variance Portfolio theory

JEL-classification: C15, D81, L94

Introduction and Main Results*

The increase of gas and carbon prices over the last year and the recent gas supply disruptions in Europe have raised concerns over security of supplies and revived the debate over the optimal power generation fuel-mix. One important research question concerns the ability of liberalised electricity markets to encourage investment in a diverse mix of technologies. Does the new industry structure bias investment incentives towards some generating technologies? And what are the potential barriers that might prevent investors from making choices consistent with the socially optimal fuel-mix?

This paper concentrates on private investors' investment incentives in liberalised electricity markets, with a particular focus on technology and fuel-mix diversification as a strategy to mitigate exposure to electricity, fuel, and carbon price risks. The first section of the paper provides a discussion of the market and institutional failures that might prevent private investors from adopting technology diversification strategies consistent with the macroeconomic socially optimal fuel mix.

There lacks a robust analytical framework to assess the complementarity of the risk-return profiles of different generation technologies and to balance the *risk reducing* benefits of portfolios of mixed technologies against the *costs* of such portfolios. The following sections of the paper attempt to develop such an integrated *quantitative* framework, based on Markowitz's Mean-Variance Portfolio theory. We show how this theory, initially developed for financial securities, can be used to determine optimal generation portfolios for countries or large power companies.

The pioneering literature used Mean-Variance Portfolio (MVP) theory to identify optimal from a *societal* perspective in the pre-liberalisation context of regulated utilities, and hence concentrated on *fuel price risk*. This paper presents the first application of MVP theory for electricity sector planning from the perspective of (large) electricity generators. This requires to take into account not only *fuel price risks*, but also *electricity* and *carbon* price risks. A new modelling approach combining Monte Carlo simulation with Mean Variance Portfolio theory is introduced to identify the portfolios which maximise returns to the stakeholders, given portfolio risk levels.

The model is calibrated using UK historical electricity, fuel, and carbon prices data from 2001-2005. Optimal generation portfolios for the three large scale base load technologies (coal, gas, and nuclear power plants) are computed using three different scenarios. In the first scenario, fuels, carbon and electricity price vary independently according to spot market historical time series. The second scenario investigates the impact of the high degree of correlation observed in the UK markets between electricity, gas, and CO_2 prices on optimal portfolios. The third scenario studies how a long-term fixed-price power purchase contract modifies the diversification incentives of power generators.

The MVP investment valuation framework introduced in this paper demonstrates the critical impact of correlation between electricity, fuel and CO_2 prices. We find that absent long-term power purchase agreements, there is little diversification value for a private investor in a portfolio of mixed technologies, because of the high empirical correlation between electricity, gas, and prices. In other words, the correlation between electricity, gas, and carbon markets makes 'pure' portfolios of gas power plants more attractive than diversified portfolios as gas plants' cash flows are 'self-hedged'.

* The authors would like to thank Shimon Awerbuch, Chris Hall, Paul Twomey, and anonymous referees for their helpful comments. This work was carried out while the lead author was at the Judge Business School, University of Cambridge, England. The views in this article are those of this author alone and do not necessarily represent the views of the IEA or of its various member countries. Financial support from the British Council and the Cambridge-MIT Institute under the project 045/P 'Promoting Innovation and Productivity in Electricity Markets' is gratefully acknowledged, as well as Platts for providing the data on electricity and fuel prices.

This is consistent with the empirical evidence, as most new power plants built in the UK in the last decade are gas-fired.

For an electric company, investing in an additional CCGT has therefore an externality value as it increases the correlation between electricity and gas prices, thereby not only reducing the volatility of the returns of the new CCGT investment, but also reducing the returns of the other CCGT units that the electricity company already operates. Our model shows that this externality effect outweighs the risk-reducing benefits of diversifying in other technologies, which suffer the opposite negative externality (especially coal plants) of reducing the correlation between electricity and gas prices.

Moreover, the positive externality associated with a gas fired power plant investment suggests that the current UK industry framework is unlikely to reward fuel mix diversification sufficiently so as to lead private investors' technology choices to be aligned with the socially optimal fuel-mix, unless investors can find counter parties with complementary risk profiles to sign long-term power purchase agreements. Indeed, in the scenario in which electricity prices are fixed through a long-term power purchase agreement, we find that optimal generation portfolios are mixed and include some coal and/or nuclear power plants.

These findings raise questions as to whether and how policy makers or regulators should modify the market framework, given the macroeconomic and security of supply benefits of a diverse fuel-mix. Our model suggests that alternative institutional risk allocation mechanisms (e.g. long-term power purchase contracts) might render capital intensive but fuel-price risk free technologies such as nuclear power or renewables more attractive to investors - and thereby provide power companies with stronger incentives for fuel mix diversification. Further research is also needed to investigate the additional measures that could be used by policy makers to align private investors' diversification incentives with the socially optimal fuel mix, such as introducing taxes differentiated by technology, or a 'diversity obligation' quota system requiring suppliers to source their electricity from various technologies.

2. Technology Diversification in Liberalised Electricity Markets

The old vertically integrated franchise monopoly model under state ownership or cost-of-service regulation was normally able to finance any required capacity in generation. That model occasionally experienced financing difficulties if governments restrained final prices (although that was more of a problem in developing countries) and certainly provided poor incentives for delivering investment in a timely and cost-effective way. Averch and Johnson (1962) demonstrated that regulated utilities might rationally prefer to invest in capital-intensive technologies. Their theoretical prediction is consistent with an emphasis on large coal and nuclear power stations in both the US and Europe. Moreover, the subordination of utilities to government direction often gave rise to other distortions of investment choices. Many countries directly controlled or influenced the fuel mix through protection to 'national' fuels (such as coal or lignite), or the financing of 'national' technologies (such as nuclear) (Newbery and Green, 1996). When examining the alleged biases in technology choice caused by market liberalisation, one should remember that public ownership and cost-of-service regulation also introduced biases.

The liberalisation of the electricity industry shifted the investment risk burden from consumers to producers. While cost-plus regulation provided investors with prospects of stable returns, in liberalised electricity markets the volatility of electricity, CO_2, and fuel prices present significant risks for an investor. One central issue to the long-term benefit of liberalization of energy markets lies in their ability to deliver sustainable investment signals, without inappropriately biasing investment incentives towards some generating technologies rather than others. That requires identifying the drivers of technology and incentives to diversify in the liberalised industry and the barriers that might prevent investors to making socially optimal fuel-mix choices?

2.1 Fuel mix diversification and corporate strategy

In a liberalised industry, investment decisions are made by individual investors. It is important to understand how the shift from central planning to decentralised investment decision making has impacted investment choices and whether the value of a diverse fuel mix is factored into utilities' corporate strategy.

In the liberalised industry, investments are profit-motivated. Utilities can no longer automatically pass on costs to consumers, and have to factor new constraints into the investment decision. When it comes to raising funds to finance a new power project, the impact of this investment on the company financial ratios has to be considered, with the pressure of stakeholders searching for high returns and a quick 'pay-back' period. In that perspective, the industry investment time frame has considerably shortened, with power investment being amortized over no longer than 15 years, as debt repayments and power purchase agreements only exceptionally exceed 10 to 15 years. The opportunity cost of a new power investment is particularly high for capital intensive technologies such as nuclear power plants.

Deregulation forced utilities to radically change their corporate strategy, and diversification now plays a central role in electricity companies' strategies. However, a closer look at the role of diversification for an electric utility reveals the complexity of that concept. Diversification can indeed apply to generation fuel, but also to plant manufacturers, fuel procurement contracts, plant geographic location, etc. It is not clear to what extent fuel mix diversification would benefit a utility, as the lowered exposure to fuel price risks has to be weighted against the gains of choosing the cheapest technology.

There is no such thing as one business model in the electricity industry, as electricity companies must decide which business segments to enter (generation, distribution, retail), the degree of vertical or horizontal integration, as well as their geographical scope. This paper investigates technology diversification from the point of view of a generation company that it is not engaged significantly in the upstream and downstream parts of the industry.

2.2 The lack of financial risk management instruments in the electricity industry

The lack of financial risk management instruments is another issue that impacts generation companies' technology and diversification choices, insofar as it might favour technologies which have a degree of 'self-hedging' in the current industry framework. For instance, gas-fired power plants revenue can be expected to be stable in electricity markets such as the UK, which exhibit strong correlation between electricity and gas prices.

When the industry liberalised in the 1990s, market analysts predicted rapid growth in the use of electricity derivatives. However, in the last quarter of 2000, the market for exchange-traded electricity futures and options virtually collapsed in the US, with knock-on effects in all electricity markets around the world (DOE, 2002). [1] Enron's collapse highlighted the problems of credit risk and default risk in electricity markets. Since 2000, market participants in the US and to a lesser extent in Europe have become increasingly cautious and have been hedging risks by relying on more traditional utility suppliers and consumers with known physical assets, and by reducing the scope of their derivative products (e.g., moving toward shorter term forward contracts).

DOE (2002) suggests that the failure of exchange-traded electricity derivatives and the lack of liquidity of the over-the-counter (OTC) markets in the US and in Europe seem to have resulted from problems in the underlying market for electricity itself, such as the lack of competition and regulatory uncertainty. In addition to these structural obstacles, the development of liquid electricity futures markets more than a few months in advance is hindered by the nature of electricity as a commodity,

1 By February 2002, the New York Mercantile Exchange (NYMEX) decided to delist all of its futures contracts due to lack of trading. The Chicago Board of Trade (CBOT) and the Minneapolis Grain Exchange (MGE) also suspended trading in electricity futures.

the extreme volatility of prices, the complexity of the existing spot markets, and the lack of price transparency (Geman, 2005).

Even with the development of robust competitive markets, however, the use of derivatives to manage electricity price risk will remain difficult, because the simple pricing models used to value derivatives in other energy industries do not work well in the electricity sector (DOE, 2002). This suggests that innovative derivatives that are based on something other than the underlying energy spot price - such as weather derivatives, marketable emissions permits, and specialty insurance contracts - will be important for the foreseeable future.[2] As financial markets regain confidence in the electricity industry, and as market participants improve their understanding of the specificities of the electricity industry, more tailored and innovative risk management instruments will emerge. But for the time being, the lack of long-term electricity specific financial risk management products limits the possibilities for generation companies to diversify their risks exposure.

2.3 From macroeconomic to microeconomic diversification incentives

Besides the possible 'short-termism' of investors, one might also worry about the ability of decentralised decision-making to take adequately coordinate individual decisions. Before liberalisation, traditional strategic planning emphasized long-term resource allocation (what type of plants, at what locations, etc.), and privately owned utilities' decisions were constrained by public utility commissions. In state-owned utilities, the link between energy policy and investment choice was more direct, making it easy to influence investment decisions to achieve the desired fuel mix.

Electricity markets may not appropriately signal for the need of diversity and flexibility at the macroeconomic level. Consider the case of increased gas dependency, where Britain faces an increased risk of large price increases for imported gas. Plant that uses fuel whose price does not move sympathetically with gas (such as nuclear and wind, and to some extent coal) would be an attractive complement in the portfolio of either a generator or investors holding shares in power companies, and to that extent diversity will be rewarded. However, the macro-economic risks associated with a large increase in the price of imported gas will not be reflected in the profit of generation from other fuels, and may even be penalised if the macro-shock causes an economic downturn and a fall in overall demand. Individual plant choices may therefore not respond to the social risks of increased fuel specialisation and reduced diversity.

A perfect market should motivate individual investment decisions leading to the socially optimal fuel mix, but the conditions for this to hold are strong – the usual General Equilibrium assumptions of a complete set of spot and forward markets or perfect foresight, price-taking behaviour by producers and consumers, risk neutrality (or adequate risk-sharing contracts), and convex production possibilities (Arrow and Debreu, 1954, Debreu, 1959). The lack of informative distant futures markets may lead to a suboptimal degree of diversity. In particular, herd behaviour (in which investors observe others' decisions, and assume they are based on superior information that justifies imitating their choices)

2 Commonly used electricity derivatives traded in OTC markets include forward price contracts, swaps, options, and spark spreads. Several designs for electricity futures also appeared briefly on the NYMEX, CBOT, and MGE exchanges before being withdrawn. Although derivatives that focus on price risk *per se* have had mixed success in the electricity industry, three interesting tangential derivatives for managing risk in the industry are also being used: emissions trading, weather derivatives, and insurance contracts. SO2 and NOx allowance trading has flourished in the US in recent years and the recently launched EU Carbon Emission Trading Schemes is already experiencing large trading volumes. To manage weather risk, some independent power producers have weather adjustments built into their fuel supply contracts. Other large energy companies and power marketers are now using 'weather hedges' in the form of custom OTC contracts that settle on weather statistics. Lastly, to cover the risk from low-probability events such as a plant breakdown, multiple-trigger derivatives and specialty insurance contracts can be used to complement normal derivative products (DOE, 2002).

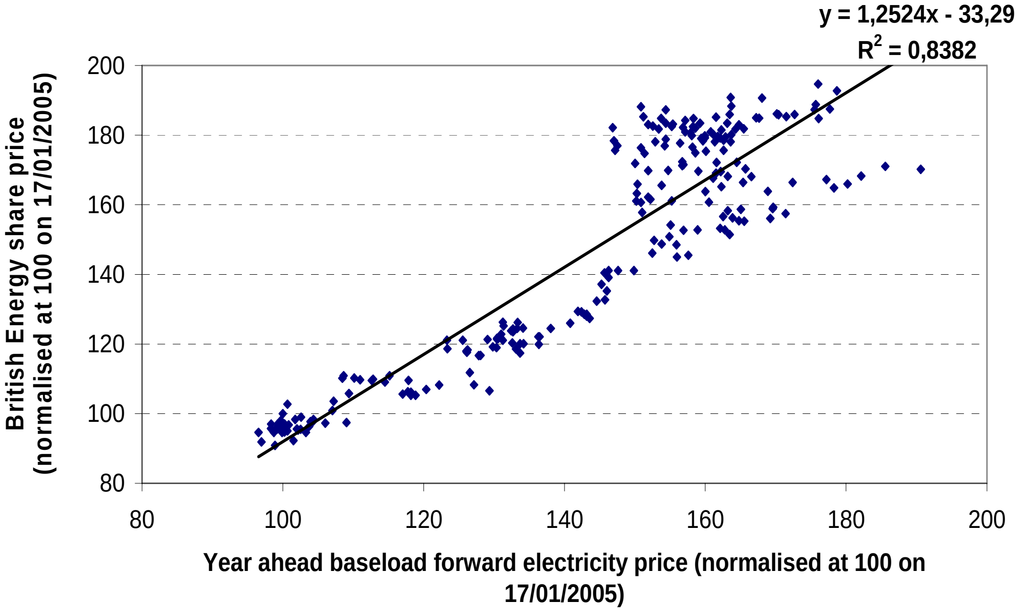
may encourage investment in one or two dominant technologies, as well as waves of investment leading to boom-and-bust investment cycles (Ford, 1999 and 2001, and Olsina et al., 2005).

Moreover, imperfections in capital markets may limit the ability of utilities to diversify their risk exposure. Technology diversification does not appear as a primary motivation for cross-participations in utilities' equity. However, alternative diversification strategies to handle fuel risks have developed in response to capital market imperfections. Long-term fixed-price fuel procurement contracts are the most common such strategy, which does not require physical ownership of the production assets. For example, the gas and electricity utility Centrica took steps in 2004 to diversify its power generation portfolio by agreeing its first coal-indexed power purchase deal with International Power. The three-year agreement starting in October 2004 is linked to the monthly average of the API2 coal market index and will see International Power’s Rugeley coal station supplying 250MW of peak electricity to Centrica’s British Gas domestic energy business. Centrica owns a number of gas-fired power stations in the UK and also has an off-take agreement with nuclear generator British Energy. It had been seeking exposure to the coal power market to balance its power generation book and had considered taking an equity stake in a UK coal-fired power plant or off-take agreements from coal stations. The coal-indexed deal will allow Centrica to diversify into the coal power market without the cost of buying ageing coal power plant.

2.4 Technology diversification and the consumer interest

The standard Arrow-Debreu economic theory of decision-making under risk postulates a complete set of competitive risk and futures markets on which all goods and services can be traded now to ensure that investment decisions are efficient (see e.g. Arrow and Hahn, 1971). While this is wildly unrealistic, it serves as a useful benchmark for identifying possible market failures. The institutional counterparts to the imagined full set of Arrow-Debreu markets are claims on the profits of companies (i.e. shares in those companies) and futures markets. These can go some way towards offering hedging instruments to share and hence reduce the cost of risk.

Figure 1: Correlation between British Energy share price and baseload forward annual power price in 2005



In the present context of risky future energy prices, consumers would (if they were well-informed) wish to hedge such risks. To be more precise, high gas prices that translate into high electricity prices will harm consumers who buy electricity. High gas prices are likely to lead to high profits in gas producing companies. One natural hedge would be for consumers to hold shares in companies that specialised in producing gas (or buying gas on long-term fixed price contracts). Another hedgewould be for consumers to hold shares in a specialised nuclear power generating company that would earn higher profits when selling at higher electricity prices. For instance, from the time when British Energy was relisted on 17 January 2005 and the end of 2005, British Energy Shares have exhibited a 91% correlation to the one-year forward electricity price in the UK (see Figure 1).

In both cases the extra profits from the shares could offset the extra costs of electricity. Note that holding shares in a gas-fired electricity company would be no use at all, as higher gas and electricity prices would leave their profits more or less unchanged. Finally, consumers could theoretically hedge directly by buying futures in gas (or more directly in electricity). These would pay off in high gas/electricity states of the world and compensate for the high electricity prices.

However, only an extremely small number of commodities are competitively supplied and both storable and homogenous enough to support liquid futures markets. Oil products and gas satisfy these conditions in some jurisdictions (notably the US) where there are futures markets, but gas is not sufficiently competitively traded in most of Europe to offer reliable hedges or sustain liquid futures markets. Electricity (whose value can vary each hour and across space) is not sufficiently homogenous for really low cost liquid futures markets to take off, although some products (base and peak seasonal and annual) are traded in some markets (though with relatively low turnover/physical traded volume).

Shares in companies also offer some insurance, but few companies are sufficiently specialised to offer pure hedges, perhaps because their value as such is attenuated by the information costs facing individual consumers. For many purposes, these information and transaction costs give an advantage to portfolio companies (or mutual funds for small investors), and as such remove the hedging options needed to reflect consumer demand for diversity.

All of this suggests that utilities are likely to have to bear much of the cost of risk in their investment decisions, unless they can find counter-parties with complementary risk attitudes. Again the simple story above is illuminating – risks that profit companies may harm consumers and vice versa, giving rise to the prospect of profitable exchange (as the Centrica example shows). A supply company selling electricity at fixed prices to final consumers is one natural counter-party to a generation company selling electricity at variable prices but burning fuel whose price is un-correlated with the electricity price. Vertical integration between such companies avoids the need for contracts or cross-ownership of shares and is common in these markets. Energy-intensive consumers such as pulp and paper manufacturers may be willing to equity-finance nuclear power plants for similar reasons (and do so in Finland). One test of how well such risk markets or their surrogates might work is whether a nuclear power company's shares are seen as complementary or substitutable in consumers' portfolios or whether ignorance and/or information costs give an advantage to energy companies in constructing physical rather than financial portfolios of plants.

This suggests that utilities are likely to have to bear much of the cost of risk in their investment decisions, unless they can find willing counter-parties with complementary risk attitudes. The working assumption in the rest of this paper is that ignorance of risks and/or information costs give an advantage to energy companies in constructing physical rather than financial portfolios of plants, and that therefore the best case for plant diversity is probably within the portfolio of large well-capitalised energy companies, rather than stand-alone share-issuing specialised companies (which theoretically ought to offer more adaptable portfolio hedging options for consumers). The rest of the paper explores the potential of Mean-Variance Portfolio Theory as an analytical framework for private investors to value technology and fuel-mix diversity in liberalised electricity markets.

3. Applying MVP Theory to Determine Optimal Generation Portfolios in Liberalised Electricity Markets

Mean-Variance Portfolio (MVP) theory, initially developed for financial securities, can be applied to generation assets to determine the optimal portfolio for a country or generation company. MVP theory makes assumptions on the assets considered and investors' behaviour (such as risk aversion), which are discussed in detail in the Appendix in the context of investment in electricity markets. The important implication of portfolio-based analysis is that the relative value of generating assets must be determined not by evaluating alternative assets, but by evaluating alternative asset portfolios. Energy planning therefore needs to focus less on finding the single lowest cost alternative and more on developing efficient (i.e. optimal) generating portfolios.

Bar-Lev and Katz (1976) pioneered the application of MVP theory to fossil fuel procurement in the U.S. electricity industry. By applying an MVP approach on a regional basis, they determined the theoretical efficient frontier of fossil fuel mix for various regulated utilities and compared it to the actual experience of the electric utilities. Bar-Lev and Katz (1976) showed that generally the electric utilities efficiently diversified, but that their portfolios were generally characterised by a relatively high rate of return and risk, which they interpreted as being a consequence of the 'cost-plus' regulatory regime encouraging utilities to behave in a risky way.

Humphreys and McClain (1998) use MVP theory to demonstrate how the energy mix consumed in the U.S. could be chosen given a national goal to reduce the risks to the domestic macro economy of unanticipated energy price shocks. They note that the electric utility industry has moved towards more efficient points of production since the 1980s, and that the switch towards natural gas in the 1990s might be driven by the desire for higher returns to energy investment in the industry.

Awerbuch (1995 and 2000) evaluates the U.S. gas-coal generation mix and shows that adding wind, photovoltaics, and other fixed-cost renewables to a portfolio of conventional generating assets serves to reduce overall portfolio cost and risk, even through their stand-alone generating costs may be higher. Awerbuch and Berger (2003) use MVP to identify the optimal European technology mix, considering not only fuel price risk but also O&M, as well as construction period risk.

3.1 Applying MVP theory in liberalised electricity markets requires to focus on profits risk rather than production costs risk

The literature applying MVP theory to identify optimal fuel mix portfolios has concentrated on regulated utilities (Bar-Lev and Katz, 1976) or adopted a national perspective (Humphreys and McClain, 1998, Awerbuch, 1995, 2000, and 2004, Awerbuch and Berger, 2003). The focus of these studies has therefore been on the *production costs* of different generation technologies. These studies define portfolio return in the case of electricity generating assets as the reciprocal of unit generating cost (reciprocal of cost per kWh) and price risk in terms of price volatility per holding period (per year). Based on projected unit costs and volatility covariation patterns, they determine 'efficient' (i.e., optimal) portfolios of generating assets. Efficient generating portfolios therefore expose society to the minimum level of risk needed to attain given energy cost objectives. As stated in Awerbuch and Berger (2003):

> Our analysis is cost-based, since from a societal perspective, generating costs and risks are properly minimised […]. Since the analysis and the expected portfolio returns are cost-based, variations in electricity market prices are not relevant.

This approach is not appropriate to identify optimal fuel-mix portfolios for electric companies in liberalised electricity markets. Private investors cannot be expected to compare different generating technologies on their production *costs*, but rather on their expected risks and *returns*. Electricity price risk (and in Europe CO_2 price risk) is also relevant for determining optimal portfolios.

3.2 Applying MVP theory when fuel, CO_2*, and electricity prices are uncertain*

Those studies that focus on generation *costs* are usually based on traditionally estimated levelised generation costs taken from various sources, such as IEA (2000) used by Awerbuch and Berger (2003). The estimation of market or historic cost risk for each technology derives therefore in a straightforward manner from the market or historic cost variations of the fuel costs associated with each technology. Data requirements consist of historical time series of yearly average fuel prices, and the correlation between such prices.

Introducing electricity and CO_2 price risk complicates the calculation of the optimal generation portfolio.[3] Indeed, when the electricity price is set at the levelised cost of production, both the level and correlation between the returns of different generation technologies derive directly from the level and correlations of fuel costs of these different technologies. However, when electricity and CO_2 prices are determined in liberalised markets, the level of correlation between the returns of the different technologies can no longer be deduced directly from the underlying fuel costs and their correlations.[4] One needs to take into account the impact of electricity and CO_2 price risk on the different technologies' return correlations.

Data on the correlation between electricity price, CO_2 price, and the different fuel prices are therefore required in addition to data on the correlation between different fuel prices. Because the correlation of the returns of the different technologies when both costs (fuel prices, CO_2 prices) and returns (electricity prices) cannot be inferred directly from empirical data, we introduce an intermediate step using a Monte-Carlo simulation to get a proxy of the correlation of the returns of the different technologies.

We define the returns and risks of different generation technologies as respectively the expected Net Present Value (ENPV) per unit of capacity (per GWe) of an investment in any technology, and the standard deviation of the ENPV per unit of capacity (per GWe).[5] Similarly, the correlation between the returns of different technologies is defined as the correlation between the ENPVs of the different technologies.[6]

The different steps of the analytical procedure used to compute the efficient MVP portfolios can be decomposed as follows:

- A discounted cash flow model of the different technologies is implemented.
- Historical time series of daily electricity, CO_2, and fuel (gas and coal) prices are used to derive the volatility and cross correlations of each of these parameters in the UK market (discussed in the Appendix).
- A Monte Carlo simulation is run to compute the distribution of Net Present Value (NPV) of an investment in the different technologies. The fuel, electricity, and CO_2 prices are represented by

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3 Awerbuch and Berger (2005) point out that multiplying their cost-based portfolio returns, [kWh/cent], by the price of electricity [cent/kWh] yields a dimensionless measure of return that is precisely analogous to the financial measure of return. They notice, however, that this procedure raises questions regarding the appropriate electricity price to use. They suggest that a relevant, dimensionless return measure for our purposes would be based on an averaged cost representative of long-term equilibrium electricity market prices.

4 One can imagine building a merit order model in which the price of electricity is set by the marginal cost of generation at different levels of demand, which will in turn be determined by the capacity stock and fuel prices, so that there are links between fuel costs and electricity prices, but they depend on the plant portfolio and demand as well.

5 The normalisation of risks and returns per unit of capacity is equivalent to a normalisation per unit of output as we assume an identical availability factor of 85% for the base-load three technologies considered.

6 Financial returns generally reflect a benefit divided by an input, where both are dollar-dimensioned: i.e. 'dollars returned/dollars invested. The financial return measure is therefore dimensionless, a property that does not hold for our NPV return measure (£million/GWe). We could make it dimensionless by dividing the ENPV by the initial 'overnight' capital investment per GWe.

normally distributed random variables, whose cross-correlations and standard deviations are calibrated using data derived from the UK historical time series.

- An econometric regression of the 100,000 simulations of the different technologies returns is run to determine the correlation of the returns of the different technologies.
- MVP theory is applied to compute the returns (Expected NPV) and risks (standard deviation the NVP) of different portfolios of the three technologies considered, using the correlation factors between technologies computed at the previous step.

3.3 Model data inputs

The parameters of the discounted cash flow model correspond to three base-load technologies (CCGT, coal and nuclear plants) available for new build in the UK over the period 2001-2005. All the costs are expressed in real 2005 British Pounds. Cost and technical parameters are derived from the MIT *'The Future of Nuclear Power'* study (Deutch et al., 2003), updated with the International Energy Agency Costs of Generating Electricity study (IEA, 2005). *Table 2* summarises the model costs and revenues assumptions.

Table 2 - Cost and Technical Parameters

Parameters	Unit	Nuclear	Coal	NGCC
		Technical parameters		
Net capacity	MWe	1000		
Capacity factor	%	85%		
Heat rate	BTU/kWh	10400	8600	7000
Carbon intensity	kg-C/mmBTU	0	25.8	14.5
Construction period	year	5	4	2
Plant life	year	40	30	20
		Cost parameters		
Overnight cost	£/kWe	1140	740	285
Incremental capital costs	£/kWe/yr	11.4	8.6	3.4
Fuel costs	£/mmBTU	See distribution parameters		
Real fuel escalation rate	%	0.5%	0.5%	1.2%
Fixed O&M	£/kWe/year	36	13	9
Variable O&M	£/MWh	0.23	1.93	0.3
O&M real escalation rate	%	0.5%		
Nuclear Waste fee	£/MWh	0.6	0	
		Financing parameters		
Projected Inflation rate	%/year	3%		
Real Discount rate	%	10%		
Marginal Corporate Tax	%	30%		
		Regulatory actions		
Carbon tax	£/tC	See distribution parameters		
Carbon price esc. rate	%	1%		
		Revenues		
Electricity price	£/MWh	See distribution parameters		
Electricity price esc. rate	%	0.5%		

The model provides a fairly realistic description of the specificities associated with an investment in the three different technologies in the UK over the period 2001-2005. For example, the investment time lag is five years in the case of nuclear, four years in the case of coal, while it is only two years in the case of the CCGT plant.[7] The capital costs ('overnight cost' and 'O&M incremental cost') are much higher for the nuclear plant, and to a lesser extent for the coal plant, than for the CCGT plant,

7 These investment lags are estimates of the construction times, assuming that the construction permit and regulatory approval have been obtained.

while the converse is true for fuel costs. Nuclear plant incurs a 'nuclear waste fee' to cover the cost of decommissioning and nuclear waste treatment. The cost of CO_2 emissions related to the European Emission Trading Scheme is represented by a 'carbon tax'.[8]

The three plants are assumed to operate base-load with an average annual capacity availability factor of 85%.[9] Operating flexibility (and hence volume risk) is modelled by assuming that they can stop generating whenever electricity, gas, and CO_2 prices make it uneconomic (although as the fuel prices are annual averages this amounts to either making the plant available for the whole year or mothballing it for that year. More subtle variations in annual load factors cannot be readily addressed.)

The financing structure of the model is kept simple. The corporate tax rate is 30% in England, and we model three scenarios for the real weighted average cost of capital (WACC), 5%, 8% and 10%. Plant life-times of respectively 20, 30, and 40 years for gas, coal and nuclear plants represent also the capital recovery period.

3.4 Costs and revenues uncertainties

Contrary to the previous literature applying MVP theory to determine the optimal technology mix portfolio, the focus of this paper is on both cost and revenue risks in liberalised electricity markets. We limit the costs and revenues uncertainties to market risks, namely the fuel costs (gas, coal, and nuclear fuel) and CO_2 allowance price. We do not consider cost or revenue uncertainties related to technical or operational risks (e.g. construction costs overruns, plant availability factor, etc.). This simplification is assumed not to change optimal portfolios significantly since the fuel cost risks and the CO_2 allowance price risk represent a large part of the total generation costs risk for CCGT and coal plants. These other risks are a subject of a companion paper (Roques, Newbery and Nuttall, 2006).[10]

When modelling commodity prices, it is important to distinguish price variability from price risk. In the case of electricity, price variability corresponds to usual daily and seasonal fluctuation patterns which are easy to forecast (Geman, 2005). The focus is here on price risk. Fuel and CO_2 allowances are assumed to be bought and sold on spot markets, or through contracts indexed on the spot market price, thereby subjecting generators to annual price volatility.[11]

In order to Monte Carlo simulate the net present value of an investment in any of the three technologies, empirical data on fuel costs, CO_2 allowance prices, and electricity prices are needed. These risky parameters are modelled by a normally distributed random variable. The mean value, standard deviation, and correlation coefficients between these different distributions are required.

The focus is on the UK market. Time series of daily UK forward base and peak-load electricity prices, daily forward gas and coal prices from January 2001 to August 2005, and daily European CO_2 allowances prices from October 2004 to August 2005 were analysed (see Appendix 2 for a detailed study of these time series). The period investigated was limited to these 5 years of data as it corresponds to the start of the New Electricity Trading Arrangements (NETA) in England and Wales. Analysing a longer time period would have required us to correct for the structural changes introduced by the change of electricity market rules in Britain in 2001 and the change in market structure

8 Note that to express this as a cost per tonne of CO_2 multiply by 3.67.

9 This value represents a low estimate for nuclear (most nuclear plants are currently running at a capacity factor higher than 90% in Europe and in the US), but a relatively high estimate for gas which might be cycling up and down.

10 Awerbuch and Berger (2003) take into account operation and maintenance (O&M) cost uncertainties and construction cost uncertainties on top of fuel cost uncertainties, but show that this does not alter their findings significantly as compared to the case in which they only consider fuel cost risk.

11 The model does not account for long-term fixed-price gas procurement contracts, which are unusual in liberalised electricity markets. See Neuhoff and von Hirschausen (2005) for a discussion of the shortening of gas procurement contracts in liberalised markets.

immediately preceding this rule change. Moreover, the focus is on current diversification incentives, such that a longer time period would have required corrections for fuel mix changes over the long term.

The correlation coefficients between these different market prices were also computed, and are shown in *Table 3*. Daily quarter–ahead forward prices for base-load electricity and gas in the UK market from 2001 to August 2005 exhibit a correlation factor of 89%. The correlation between electricity and CO_2 prices from the start of trading in October 2004 until September 2005 stands at 73%. These results are consistent with Awerbuch and Berger (2003) correlation estimates.

Table 3 - Empirical prices correlation coefficients, 2001-Sept. 2005

Correlation coefficient	Base Electricity price	Gas price	Coal price	CO2 price
Base Electricity price	1			
Gas price	0.89	1		
Coal price	0.56	0.77	1	
CO2 price (Nov 04-Aug 05)	0.73	0.45	-0.46	1

The Monte Carlo simulation parameters are detailed in *Table 4*. The fuel, CO_2, and electricity prices are modelled using normal distributions, whose standard deviation and correlation coefficients correspond to the empirical estimates detailed in Appendix 2.[12] The mean of the distribution is based on 2005 average prices.

Table 4 - Monte Carlo Simulation Risk Distribution Inputs

Normal Distributions Parameters	Technology	Mean	Standard deviation
Cost parameters			
Fuel cost (£/mmBTU)	Nuclear	0.35	0.1
	CCGT	3.3	1.0
	Coal	1.3	0.6
Carbon tax (£/tC)	All	40	10
Revenue			
Electricity price (£/MWh)	All	40	10

There is no universally defined and accepted market place for uranium, such that reliable price time series are difficult to obtain. Moreover, nuclear fuel price risk is not sufficiently captured by uranium fuel prices alone, since the ore undergoes enrichment, conversion, and fabrication steps before it can be used for electricity. These additional processes are also subject to price volatility. We rely on estimates from Awerbuch and Berger (2003) for nuclear fuel price standard deviation and correlation with other fuels (the correlation coefficients of nuclear fuel with gas and coal stand respectively at -0.27 and -0.13).

12 Unless investors have a special type of utility function (quadratic utility function), it is necessary in the MVP theory to assume that returns have a normal distribution, [Copeland and Weston (1988) p. 153]. This is an approximation as actual fossil fuel and electricity prices are unlikely to be normally distributed.

3.5 Monte Carlo simulation results

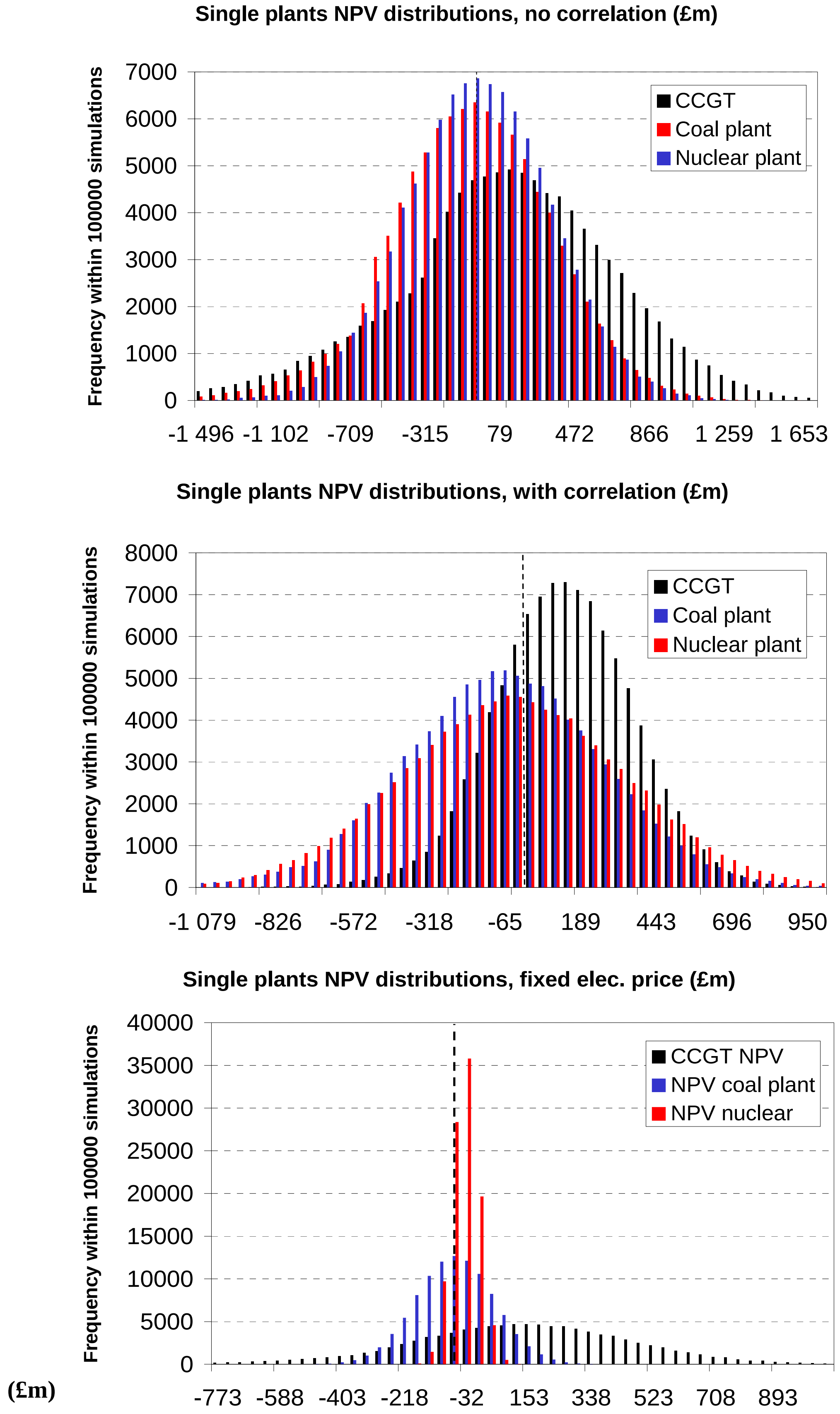
The Net Present Value (NPV) of an investment in the three technologies was simulated for three scenarios.

- In the *first scenario*, electricity, fuel, and CO_2 prices are risky but the correlation between them is set at zero. This is a benchmark scenario that would correspond to hypothetical isolated fuel, electricity, and CO_2 markets.
- In the *second scenario*, electricity, fuel, and CO_2 prices are risky and the correlation coefficients are set at the empirical values detailed in the previous section. This is the scenario representing investments in the current UK liberalised electricity market, without long-term fixed price fuel procurement or electricity power purchase agreements.
- In the *third scenario*, electricity prices are fixed while fuel and CO_2 prices are risky. This scenario corresponds to investments in the current UK liberalised electricity market for an electricity generation company which has a significant portion of its output contracted over the long-term through a fixed-price power purchase agreement. The financing of the new nuclear power plant in Finland is an extreme example of long-term power purchase agreement: the shareholders will have access to electricity at production costs during the full life of the plant in proportion to their share.

Figure 5 shows successively the NPV distributions of the different technologies in the three scenarios, for a commercial 10% discount rate (sensitivity analyses to the discount rate are presented in the Appendix).[13] In order to simplify the exposition, we assume in this section that generators cannot mothball or de-mothball plant.

13 According to the Capital Asset Pricing Model, the discount should change with the portfolio. For practical reasons, we do not vary the discount rate for each portfolio, but rather do a sensitivity analysis of the results to the discount rate, as is usual practice in investment valuation.

Figure 5 - Single plants NPV distribution, 10% discount rate



In all three scenarios, the expected Net Present Value (ENPV) of the coal and nuclear plants does not change much and is negative (respectively £m and £m), while the ENPV of a CCGT plant is positive. *Table 6* details these distributions statistics.[14]

However, the shape of the distribution of the NPVs of the different technologies varies greatly in the three scenarios.

- In the *first scenario*, with risky but not correlated fuel, CO_2, and electricity prices, the spread of the three NPV distributions is more similar, with the nuclear and coal plant still appearing less risky than the CCGT plant.
- In the *second scenario*, with risky and correlated fuel, CO_2, and electricity prices, correlation gives rise to an interesting phenomenon, as the spread of the NPV distribution of the CCGT plant becomes narrower than the spread of the NPV distributions of the coal and nuclear plants.
- In the *third scenario*, with risky fuels and CO_2 prices, but fixed electricity price, the CCGT, and to a lesser extent the coal plant, have a much more spread distribution, and therefore a much higher likelihood to make a loss.

Table 6 - Single plants NPV distribution statistics, 10% discount rate (£m)

Scenario	1st scenario: No correlation btw. fuel/C/elec.			2nd scenario: With correlations btw. fuel/C/elec.			3rd scenario: Fixed electricity price (PPA)		
Statistics	CCGT	Coal	Nuclear	CCGT	Coal	Nuclear	CCGT	Coal	Nuclear
Mean	111	-76	-42	139	-73	-43	134	-68	-41
St. Deviation	586	426	378	233	336	377	331	116	39
Minimum	-2699	-2310	-1990	-1042	-1706	-1872	-1782	-593	-208
Maximum	2447	1749	1698	1118	1462	1694	1530	451	120
Range	5146	4059	3688	2159	3169	3566	3312	1044	329

3.6 Analysis of the technologies returns correlation

In order to apply the MVP theory to identify the optimal portfolios of the three base load technologies, the data required are the returns (the ENPV per GWe) and the risks (the standard deviation of the ENVP per GWe) of the three technologies, as well as the correlations between the returns of the three technologies. An econometric regression of the 100,000 simulations of the different technologies NPVs is run to determine the correlation between the NPVs of the different technologies. The results are presented in *Table 7* for the three scenario described in the previous section and for the two cases with and without operating flexibility (i.e. the ability to mothball or de-mothball plants).

14 It should be noted that these negative NPV estimates correspond to cost and price assumptions in the UK over the period 2001-2005, characterised by relatively low gas and electricity prices by historical standards. Lower prices for coal in countries such as the US or some countries in continental Europe over the same period would yield different results and make coal more competitive.

Table 7 - Correlation coefficients between the three technologies NPVs, 10% discount rate (£m)

No operating flexibility			
Correlation of returns	**CCGT/Nuclear**	**CCGT/Coal**	**Coal/Nuclear**
Fixed electricity price	0.002	0.118	0.007
No correlation elec/gas/C prices	0.797	0.789	0.953
With correlation elec/gas/C prices	0.594	0.596	0.959
With operating flexibility			
Fixed electricity price	0.003	0.114	0.007
No correlation elec/gas/C prices	0.767	0.770	0.945
With correlation elec/gas/C prices	0.593	0.594	0.957

The first insight is that the correlation between different technologies returns is relatively high in the first two scenarios in which fuel, CO_2, and electricity prices are risky (greater than 50%). In contrast, in the third scenario with fixed electricity price, the returns of the three technologies are only slightly positively correlated.

Second, comparing the first two scenarios, the three technologies returns correlation is reduced by the correlation between electricity, fuel, and CO_2 prices. Looking at the technologies themselves, the returns of the coal and nuclear plants are generally more correlated than the returns of the CCGT and nuclear plants, or the returns of the CCGT and coal plants.

The last interesting result is that the correlation coefficients between the different technologies returns are very similar in the cases with and without operating flexibility (i.e. the possibility to mothball or de-mothball plant). Hence, in the rest of this paper, we will only consider portfolios of technologies without operating flexibility, as this does not alter significantly the results.

4. Optimal Portfolios of Two Technologies

In this section, we use the returns, risks, and correlation data from the last section to identify the optimal portfolios of the three base-load technologies, using Mean-Variance Portfolio (MVP) theory. Section 4.1 introduces Mean-Variance Portfolio theory and illustrates the impact of the correlation between nuclear and CCGT returns on optimal portfolios of the two technologies assuming some arbitrary correlation coefficients. Section 4.2 and 4.3 then examine optimal portfolios of the two technologies using the correlations coefficients derived from empirical data in the UK markets over the period 2001-2005 and shown in the previous section.

4.1 The portfolio diversification effect

Financial portfolio theory was initially developed by Markowitz (1952). It does not prescribe a single optimal portfolio combination, but a range of efficient choices.[15] Graphically these correspond to the portfolio above the *risk-return efficient frontier* when drawing the graph (portfolio return, portfolio standard deviation). Investors will choose a risk-return combination based on their own preferences and risk aversion.

Lagrange multipliers can be used to compute the efficient frontier (Bar-Lev and Katz 1976). Optimisation procedures are also available and practical (Awerbuch and Berger 2003). In such

15 See e.g. Fabozzi et al. (2002) for a recent review of the developments of Portfolio theory.

optimisation procedures, the program calculates all possible portfolio combinations and finds the efficient frontier using an iterative approach (Kwan, 2001).

When there are two assets, the calculation of the portfolios risks and returns is done by using the following procedure. The expected return $E(r_P)$ of portfolio P containing the assets A (expected return r_A, standard deviation σ_A) and B (r_B, σ_B) in proportion X_A and X_B is simply the weighted average of the two assets expected returns:

$$E(r_P) = X_A E(r_A) + X_B E(r_B)$$

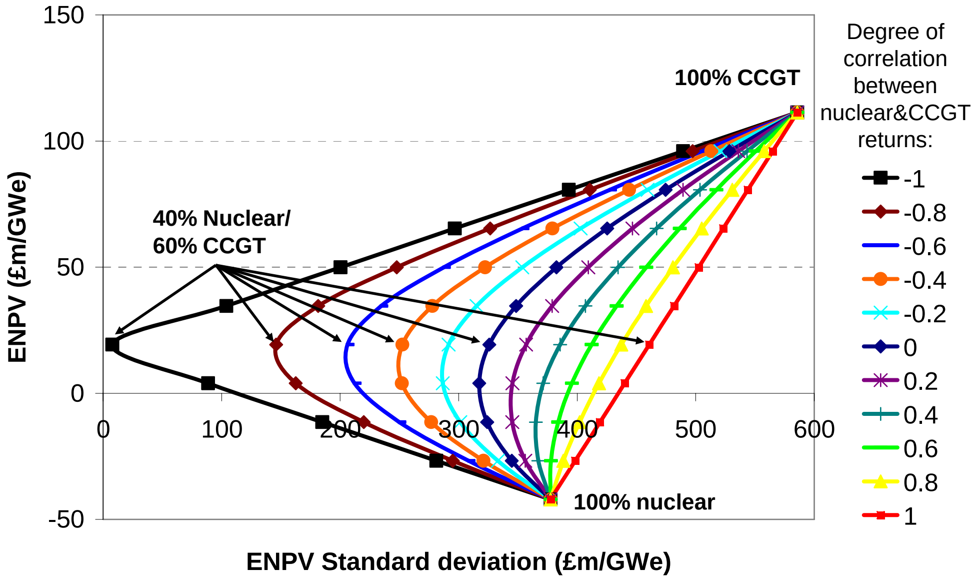
The portfolio standard deviation σ_p is defined by the following formula:

$$\sigma_p = \sqrt{X_A{}^2 \sigma_A{}^2 + X_B{}^2 \sigma_B{}^2 + 2 X_A X_B \rho_{AB} \sigma_A \sigma_B},$$

where ρ_{AB} represents the correlation between the returns r_A and r_B of the two assets.

Figure 8 illustrates the efficient frontiers of portfolios of nuclear and CCGT plants for different *hypothetical* degrees of correlation between the two technologies. A portfolio consisting of 100% CCGT plants has a higher return but also a higher risk measured by standard deviation than a 100% nuclear portfolio.

Figure 8 - Efficient frontiers for portfolios of nuclear and CCGT plants for various degrees of *hypothetical* returns correlation (10% discount rate)



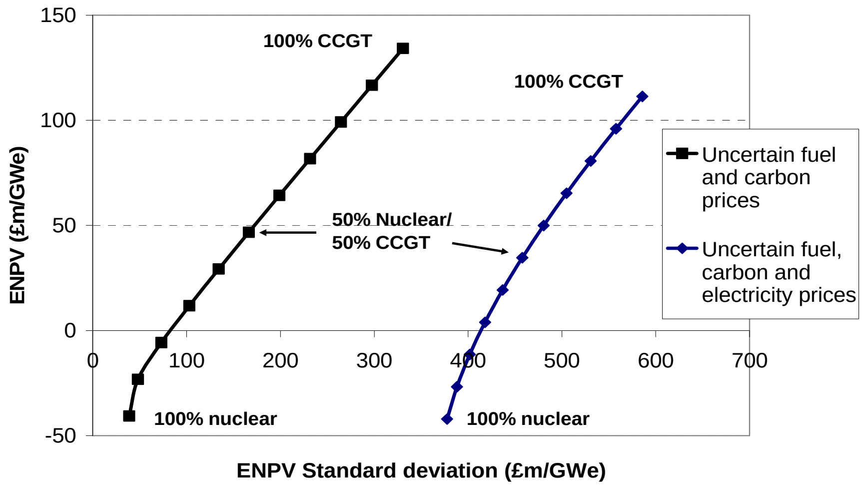
With a high correlation factor between the returns of the two technologies (such as 0.8 or 1), when nuclear is added to a 100% CCGT portfolio, returns and risk change in simple almost linear fashion. There is no particular advantage of a portfolio of 50% CCGT and 50% nuclear plants. While its risk is lower than the portfolio of 100% CCGT plants, its return is lower as well (see the right-hand end lines).

However, if the returns of a CCGT plant and a nuclear plant are less strongly correlated, then the addition of nuclear to a portfolio dominated by CCGT will produce a significant risk-reducing ‘portfolio effect’. For example, for negative correlation factors, the addition of nuclear to a portfolio of CCGT plants produces significant risk reduction relative to the decreased return. Finally, if returns of nuclear and CCGT plants move in perfect opposition (i.e. r = -1) then it will be possible to construct a portfolio with no variance as illustrated by the black line on *Figure 8*.

4.2 Optimal portfolios without correlations in fuel, CO_2*, and electricity prices*

Using now the correlation factors between the two technologies computed in the previous section, one can compute the efficient frontier for portfolios of CCGT and nuclear power plants in the UK market. *Figure 9* illustrates the efficient frontier for portfolios of nuclear and CCGT plants in two scenarios, with only fuel and CO_2 price risk (left plot, squares), and with uncorrelated fuel, CO_2, and electricity price risk (diamonds). The addition of electricity price risk without taking into account the correlation with fuel and CO_2 price makes both technologies more risky, such that the efficient frontier is just shifted to the right. This is quite intuitive insofar as a long-term power purchase agreement reduces the risk of both technologies.

Figure 9 - Efficient frontier for portfolios of nuclear and CCGT plants with and without electricity price risk, *no correlation* (10% discount rate)



In the case in which only fuel and CO_2 prices are risky (left plot, squares), the correlation of the returns between a nuclear plant and a CCGT plant is quite low (0.002), such that the addition of nuclear to a portfolio dominated by CCGT will produce a significant risk-reducing 'portfolio effect'. On the contrary, when considering the scenario with uncorrelated risky fuel, CO_2 and electricity prices (right plot, diamonds), the addition of nuclear to a portfolio dominated by CCGT does not produce a significant risk-reducing 'portfolio effect' because of the relatively high correlation of returns of the two technologies.

Nevertheless, the large difference in risk between the two technologies makes it optimal for investors to build a diversified portfolio of CCGT and nuclear plants, the choice of the preferred portfolio on the efficient frontier being determined by the risk aversion of the investor.

4.3 The impact of fuel, CO_2 *and electricity price correlation*

The two scenarios investigated in the previous subsection did not take into account correlations between fuel, CO_2, and electricity prices. When such correlations are introduced, they significantly alter both the risk-return profile of the different technologies (see NPV distributions on *Figure 5*), but also the correlation between the returns of the different technologies.

Figure 10 - Efficient frontier for portfolios of nuclear and CCGT plants for various *hypothetical* degrees of correlation between electricity/gas/CO_2 prices (10% discount rate)

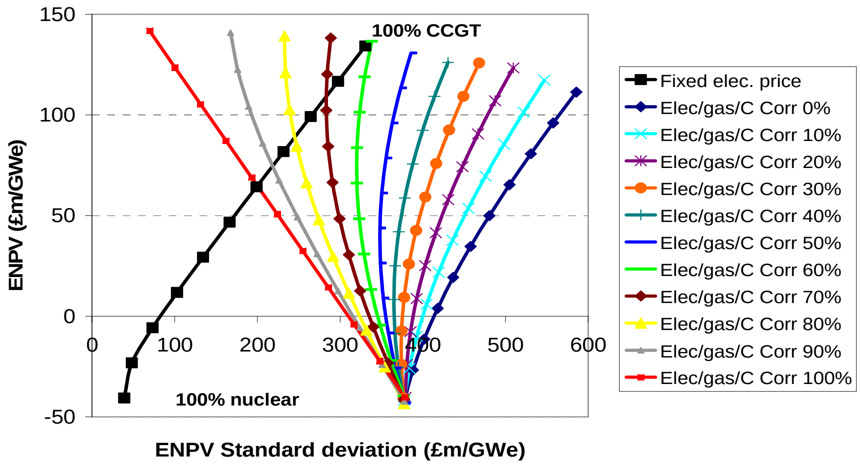
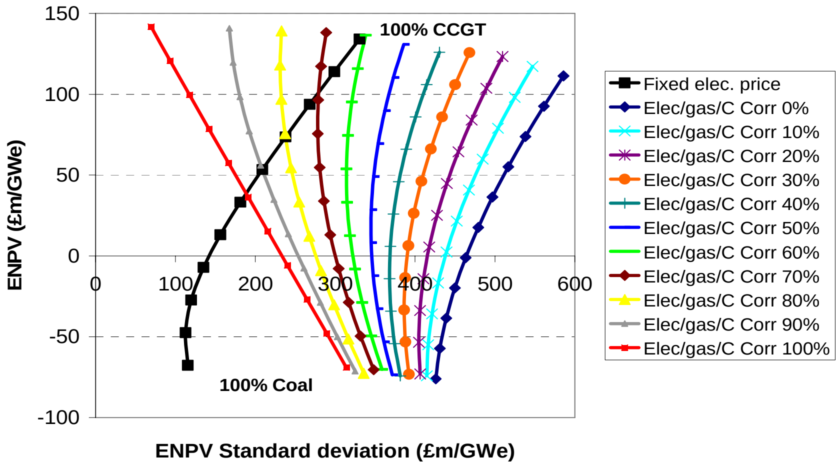


Figure 10 shows a sensitivity analysis of the efficiency frontier for portfolios of CCGT and nuclear plants with different degrees of (identical) correlation between electricity, gas, and CO_2 prices. As costs and revenues of the CCGT become more correlated, it becomes less risky while the risk return profile of the nuclear plant remains unaffected. As a result, for correlation factors greater than 50% between electricity, CO_2 and gas prices, the CCGT becomes not more risky than the nuclear plant, while yielding a higher expected return. Therefore, because of the relatively high correlation factor between the returns of the two technologies, it makes little sense for an investor to diversify a portfolio dominated by CCGT plants by investing in a nuclear plant when the correlation factor between electricity, CO_2 and gas prices is greater than 50%.

In other words, at a commercial discount rate (10%) and with the observed degrees of correlation between electricity and gas prices (89%, c.f. previous section), and between electricity and CO_2 prices (73%), a portfolio of 100% CCGT plants strictly dominates any other portfolio of nuclear and CCGT plants. This finding is consistent with the observed trend in the British market, in which most of the new capacity added recently has been CCGTs.

A graph showing the efficient frontier for portfolios of coal and CCGT plants is presented on *Figure 11* below, and leads to similar conclusions.

Figure 11 - Efficient frontier for portfolios of Coal and CCGT plants for various degrees of theoretical correlation between electricity/gas/CO_2 prices (10% discount rate)



5. Optimal Portfolios of Three Technologies

The portfolio selection method outlined above can easily be extended to portfolios of three or more assets. When there are more than two assets, portfolio risks and returns are calculated as follows (Elton and Grubber, 1994). The expected return $E(r_P)$ of portfolio P containing N assets i (expected return r_i, standard deviation σ_i) in proportion X_i is simply the weighted average of the N assets expected returns:

$$E(r_P) = \sum_{i=1}^{N} X_i E(r_i)$$

The portfolio standard deviation σ_p is defined by the following formula:

$$\sigma_p = \sqrt{\sum_{i=1}^{N} X_i^2 \sigma_i^2 + \sum_{i=1}^{N} \sum_{\substack{j=1 \\ i \neq j}}^{N} X_i X_j \rho_{ij} \sigma_i \sigma_j}\ ,$$

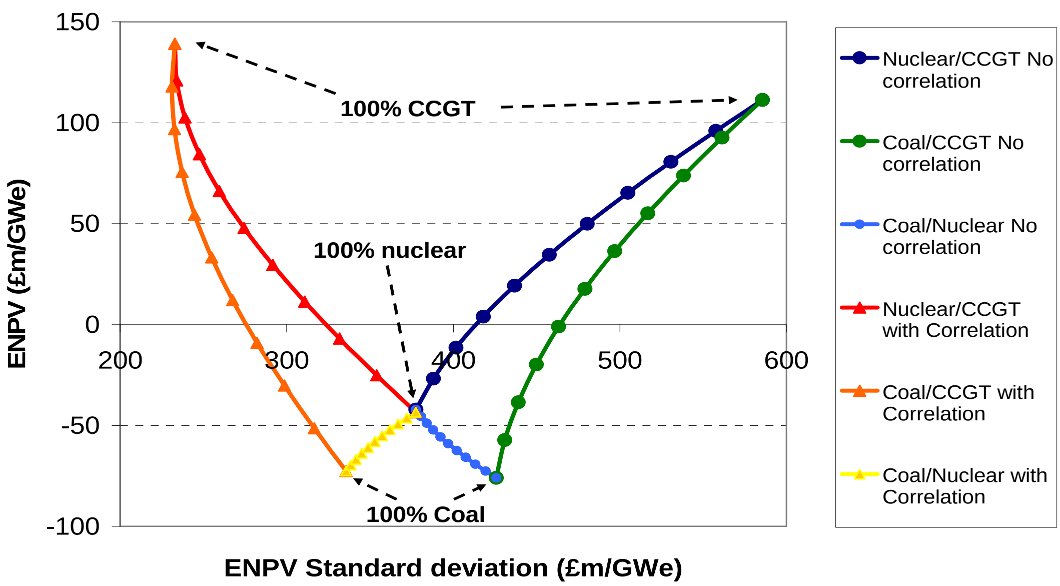
where ρ_{ij} represents the correlation between the returns r_i and r_j of the two assets.

When there are three base load technologies available (coal, CCGT, and nuclear plant), the different risk returns combinations characterising portfolios mixing the three technologies in different proportions will delineate an area in a risk-return plan. None of the interior portfolios are efficient since other mixes are available that yield either a lower risk for the same profit, or a higher profit for the same risk.

5.1 The impact of correlation between fuel, CO_2*, and electricity prices*

Figure 12 shows the feasible portfolios of Nuclear, Coal and CCGT plants in the first two scenarios. Only the frontier delineating the feasible combinations of plants is shown to clarify the graphic. In both scenarios, fuel, CO_2 and electricity prices are risky.

Figure 12 - Feasible portfolios of Nuclear, Coal and CCGT plants with and without *empirical* correlation between electricity, fuel, and CO_2 prices (10% discount rate)



The first scenario (triangle on the right-hand side) corresponds to the fictitious case in which there is no correlation between electricity, fuel and CO_2 prices, as if the electricity, fuel, and CO_2 markets were independent. In this scenario, a CCGT offers the greatest return, but is more risky than a nuclear or coal plant. The efficient frontier corresponds to the convex line with circle markers, and consists of pure combinations of nuclear and CCGT plants. There are no coal plants in the efficient portfolios, as a coal plant has both lower returns and higher risks than a nuclear plant. In this hypothetical case in which the electricity, fuel and CO_2 markets are independent, diversification strategies according to MVP theory would therefore conduce investors to invest in a mix of CCGT and nuclear plants. The greater the risk aversion of investors, the more nuclear plants there would be in the optimal portfolio.

However, in the current UK liberalised electricity industry, electricity, fuel and CO_2 prices are correlated (c.f. the times series for the UK in Appendix). The second scenario on *Figure 12* calculates the actual returns and risks of portfolios of nuclear, CCGT and coal plants given the empirically observed degrees of correlation between electricity, fuel, and CO_2 prices in the British market. The left-hand triangle delineates the set of possible portfolios.

As seen in the two-technologies case, introducing correlation dramatically decreases the riskiness of the CCGT technology, and slightly lowers the riskiness of the coal technology, such that a nuclear plant becomes the most risky investment. The optimal portfolio for an investor in this scenario is to invest only in CCGTs, as any other portfolio would both reduce returns and increase risks. This dramatic impact of the empirical correlation between electricity, fuel, and CO_2 prices is consistent with the observed behaviour of investors in the British market, which have invested heavily in CCGTs during the last decade, and have not seemed to value highly fuel mix diversity.

Figure 13 - Interaction between project cost and cash-flow – Source: Awerbuch (2004)

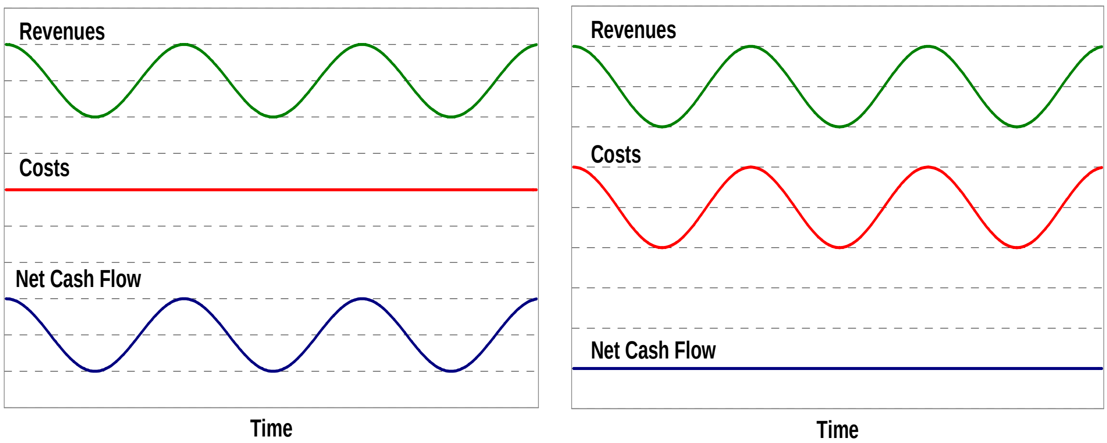


Figure 13 from Awerbuch (2004) illustrates the point. It shows how revenue, cost and net cash flow interact for two planned project alternatives that produce the same product using different production processes. The project on the left-hand side has a variable revenue (electricity price) and steady cost (nuclear fuel), so that its net cash-flow fluctuating. The project on the right-hand side is characterised by both risky cost (gas price) and risky revenue (electricity price), but has a riskless cash-flow as cost and revenue are perfectly correlated.

5.2 The impact of long-term power fixed-price power purchase agreements

Our analysis differs from previous applications of MVP theory to identify optimal generation portfolios in that it explicitly includes electricity price risk, and is therefore not cost-based but profit based. This section explores the impact of long-term power purchase agreements on optimal generation portfolios, by comparing optimal MVP theory portfolios in the second and third scenarios (the latter corresponding to the case in which electricity prices are fixed thanks to a long-term contract).

Figure 14 - Efficient frontier for portfolios of Nuclear, Coal and CCGT plants with fixed and risky electricity prices (10% discount rate)

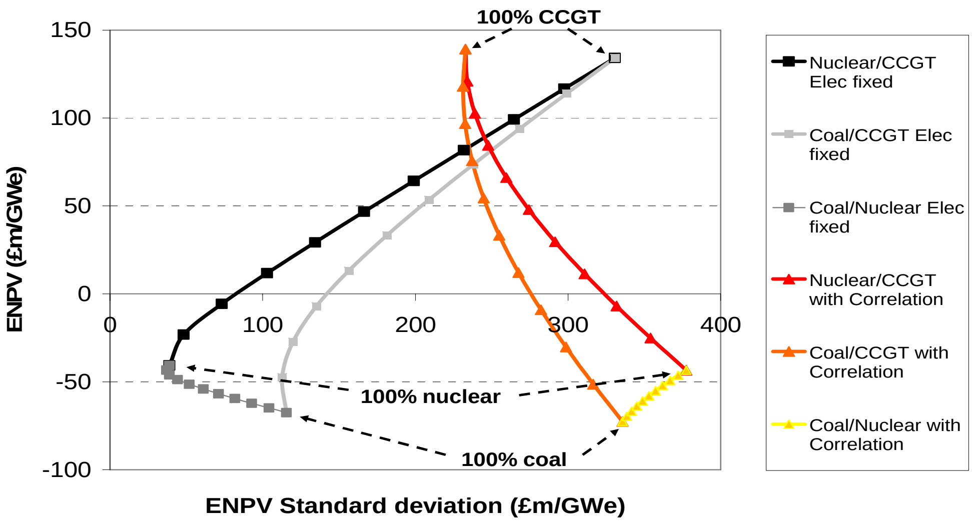


Figure 14 shows that the set of optimal portfolios in the two scenarios are very different. When the electricity price is fixed thanks to a long-term power purchase agreement, efficient portfolios lie on the efficient frontier represented by the line with square markers. The optimal portfolios consist of combinations of CCGT and nuclear plants in various proportions, depending on the investor's risk aversion.

When the electricity company sells its output on spot markets or with contracts which are indexed on the spot market, and is thereby exposed to annual electricity price risk, the optimal portfolios from a private electricity company perspective are very different. The efficient frontier consists of the upper left part of the line marked by triangles. Therefore, efficient portfolios for private investors in the current electricity market will be largely dominated by CCGT, with possibly a few coal plants.

This difference between the optimal MVP portfolios with and without long term power purchase agreements points towards a critical issue as regard to generating companies' investment risk management strategies. The first section discussed the possible risk hedging strategies for electricity companies, and concluded that utilities are likely to have to bear much of the cost of risk in their investment decisions, unless they can find counter-parties with complementary risk attitudes to sign long term contracts.

Such agreements are, however, quite rare in liberalised markets, such that the best case for plant diversity is probably within the portfolio of large well-capitalised energy companies. As a consequence, the second scenario seems more realistic, and is coherent with the observed dominance of portfolios of CCGTs, possibly with some coal plants in the UK electricity market. The third scenario shows, nevertheless, that if generation companies can find counter-parties with complementary risk attitudes, or if they are guaranteed a stable revenue stream (through for instance government subsidies or feed-in tariff), then diversifying away from CCGTs by investing in nuclear becomes the optimal strategy.

6. Conclusions and Policy Implications

MVP theory applications to the electricity sector have concentrated on identifying optimal generation portfolios at the country level or for regulated electric utilities, and have therefore focussed on generation *costs* when fuel prices are risky. This paper has applied MVP theory to identify optimal generation portfolio in a liberalised electricity industry. Fuel, CO_2 and electricity price risks have been taken into account, and the focus has been on *returns* rather than *costs* (encompassing therefore both costs and revenue risks).

A modelling approach combining empirical data with Monte Carlo simulation was introduced, which allows one to compute the correlation between different technologies expected NPVs per GWe of installed capacity when fuel, electricity, and CO_2 prices fluctuate, and then to apply MVP theory to identify optimal generation portfolios. The model was calibrated for the UK market, and we found that optimal portfolios for a private company contain mostly CCGT plants, possibly with some coal plants, depending on the risk aversion of the investors. This appears consistent with the empirical evidence which shows that almost all new power plants in the UK in the last decade have been CCGTs.

We also examined optimal generation portfolios when investors can secure a long term power purchase agreement, and showed that in that case optimal portfolios would contain a mix of nuclear and CCGT plants. While finding counter-parties with complementary risk attitudes might be difficult for investors in current liberalised electricity markets, recent experience with new nuclear build in Finland suggests that such long term arrangements might interest some specific industrial consumers. Moreover, this finding is also relevant in the current debate about the role of government in electricity markets, as it shows that if a generating company were granted a stable source of revenue through institutional (e.g. long-term capacity contract) or market changes (e.g. capacity mechanism), or through other support such as a feed-in tariff for nuclear, then optimal generation portfolios would integrate some share of nuclear power generation.

The dominance of CCGT in optimal generation portfolios can be traced back to the high empirical correlation between electricity and gas prices (and CO_2 prices) which reduces the return risk of this technology. The correlation between electricity and gas prices in particular warrants further research. By investing in one single fuel technology (e.g. CCGTs), private investors not only take into account the expected returns of this investment, but the positive externality effect of this investment on the correlation between electricity and gas markets. In a relatively isolated electricity market with little interconnection capacity, such as in England and Wales, the more investors invest in CCGTs, the higher the gas-fired plants' share of the fuel mix, the more closely correlated the electricity price with the gas price (see the Appendix for a discussion of the interaction of gas and electricity markets).

For an electric company, investing in an additional CCGT has therefore an externality value as it increases the correlation between electricity and gas prices, thereby not only reducing the volatility of the returns of the new CCGT investment, but also reducing the returns of the other CCGT units that the electricity company already operates. Our model shows that this externality effect outweighs the risk-reducing benefits of diversifying in other technologies, which suffer the opposite negative externality (especially coal plants) of reducing the correlation between electricity and gas prices.

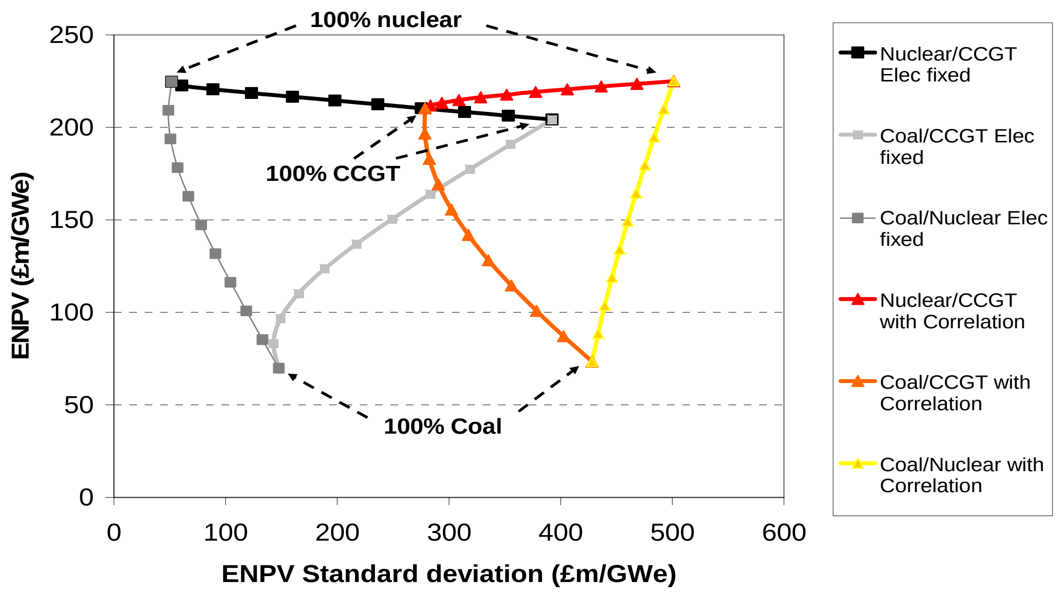
These findings raise questions as to whether and how policy makers or regulators should modify the market framework, given the macroeconomic and security of supply benefits of a diverse fuel-mix. Introducing taxes differentiated by technology, or a 'diversity obligation' quota system requiring suppliers to source their electricity from various technologies are the two typical alternatives that could be used by policy makers to align private investors' diversification incentives with the socially optimal fuel mix.

Finally, it should be emphasised that this paper concentrated on the UK market, with cost and price assumptions corresponding to the period 2001-2005, characterised by relatively low gas and electricity prices by historical standards. Application of the analytical approach developed in this paper to other countries with a different fuel mix and different prices and cost assumptions would be interesting to confirm the results of the paper. Besides, this study focussed on the three main base load options available over that period, and an extension to include other generating technologies such as renewables or peaking plant technologies would also be interesting.

7. Appendix 1: Sensitivity Analysis to the Discount Rate

7.1 Optimal portfolios of three technologies with and without long-term power purchase agreements

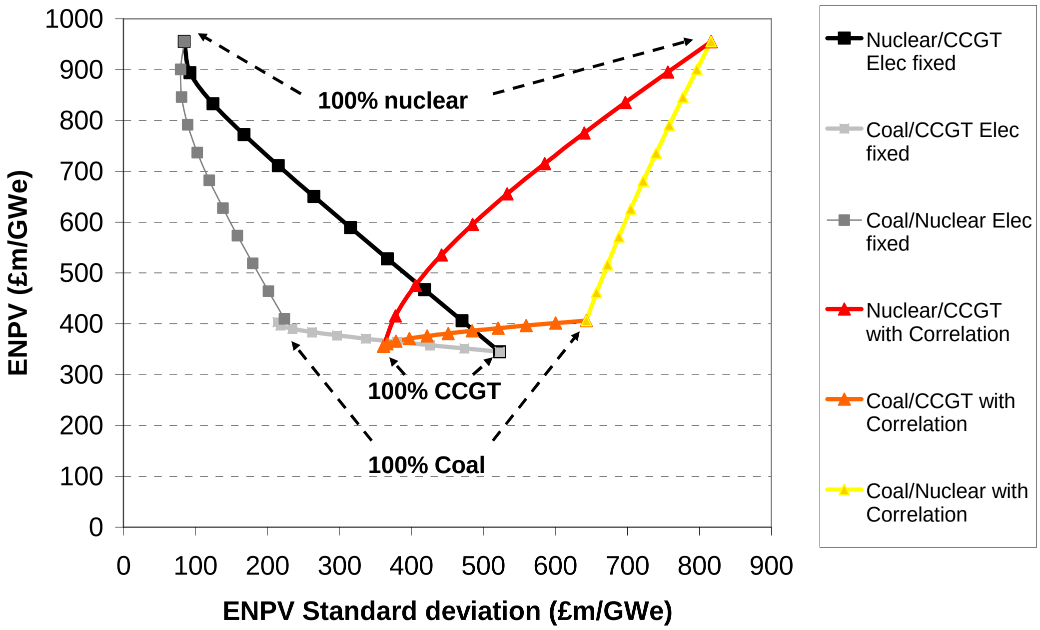
Figure 15 - Efficient frontier for portfolios of Nuclear, Coal and CCGT plants with *fixed and risky* electricity prices (*8% discount rate*)



For a discount rate (WACC) of 8%, all three technologies have positive ENPV. The nuclear plant ENPV is similar to the CCGT ENPV, and higher than the coal plant ENPV. The relative riskiness of the three technologies does not change significantly, with nuclear being less risky than gas and coal when only costs risk is taken into account, and the CCGT becoming much less risky than nuclear when both revenues (electricity price) and costs (gas price) risks are taken into account, due to the high correlation of these two streams in the British market.

As a consequence, the finding that optimal private investors portfolios are predominantly gas based when investors are subject to electricity price risk, while optimal portfolio contain a majority of nuclear when generators can obtain a long term power purchase agreement is the same as with a 10% discount rate (see *Figure 15*).

Figure 16 - Efficient frontier for portfolios of Nuclear, Coal and CCGT plants with *fixed and risky* electricity prices (*5% discount rate*)



With a 5% discount rate, the nuclear plant ENPV is much higher than the ENPV of a coal of CCGT plant, which are similar. The relative riskiness of the three technologies does not change significantly, with nuclear being less risky than gas and coal when only costs risk is taken into account, and the CCGT becoming much less risky than nuclear when both revenues (electricity price) and costs (gas price) risks are taken into account, due to the high correlation of these two streams in the British market.

Similarly to the 10% and 5% discount rate cases, optimal portfolios when generators can obtain a long term power purchase agreement contain a majority of nuclear. However, the much higher ENPV of nuclear implies that efficient portfolios for investors subject to electricity price risk do not contain exclusively CCGTs, but that any combination of nuclear and CCGT plants is efficient, depending on the risk aversion of investors (see *Figure 16*). Risk adverse investors, for instance, are likely to choose a portfolio dominated by nuclear plants.

7.2 Optimal portfolios of three technologies with and without correlation between fuel, CO_2*, and electricity prices*

Figures 17 and *18* contrast the hypothetical optimal generation portfolios in the case when electricity, fuel, and CO_2 prices are uncorrelated with the case in which these prices exhibit the UK electricity market historical correlation over 2001-2005 for a discount rate of respectively 8% and 5%. Both cases confirm the critical role of the correlation between gas, CO_2, and electricity prices in making CCGT the dominant technology.

Figure 17 - Feasible portfolios of Nuclear, Coal and CCGT plants with and without *empirical correlation* between electricity, fuel, and CO_2 prices (*8% discount rate*)

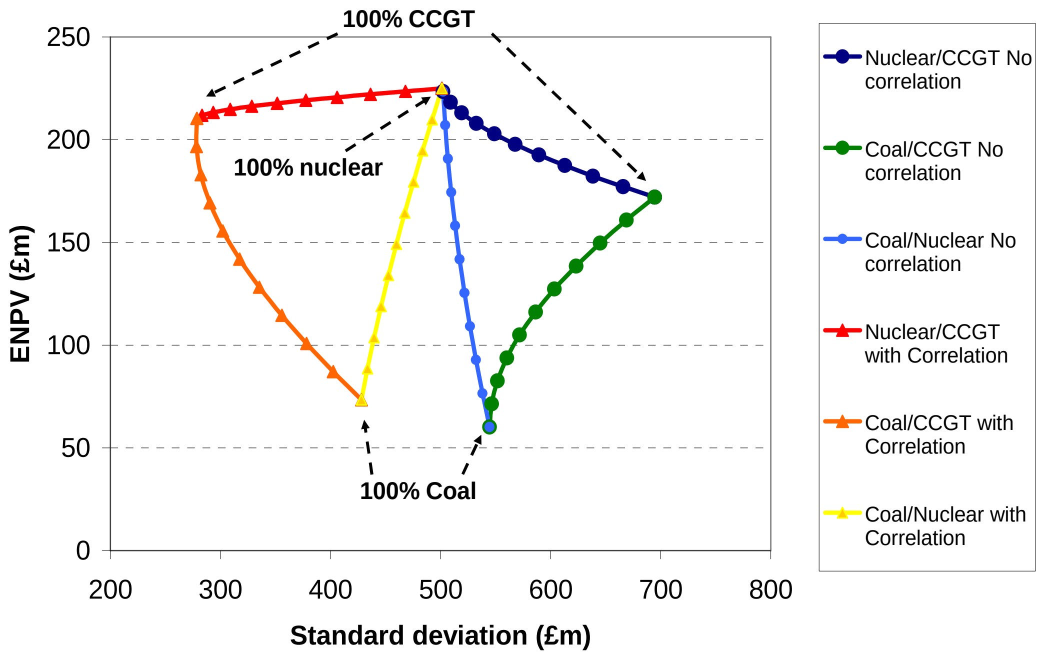
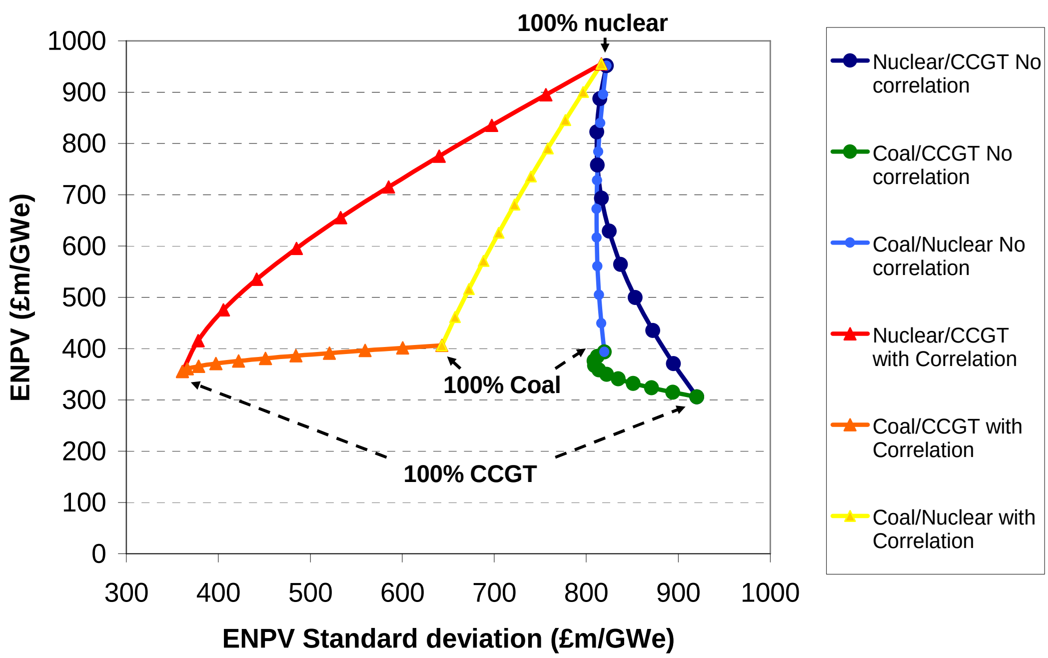


Figure 18 - Feasible portfolios of Nuclear, Coal and CCGT plants with and without *empirical correlation* between electricity, fuel, and CO_2 prices (*5% discount rate*)



8. Appendix 2: Empirical Correlation between Electricity, Gas, Coal and CO_2 Prices in the UK

Figure 19 shows times series of daily UK forward base-load electricity prices, daily forward gas and coal prices from January 2001 to August 2005, and daily European CO_2 allowances prices from October 2004 to August 2005.[16]

Figure 19 - Evolution of forward UK electricity, gas, coal and CO_2 prices (2001-2005)

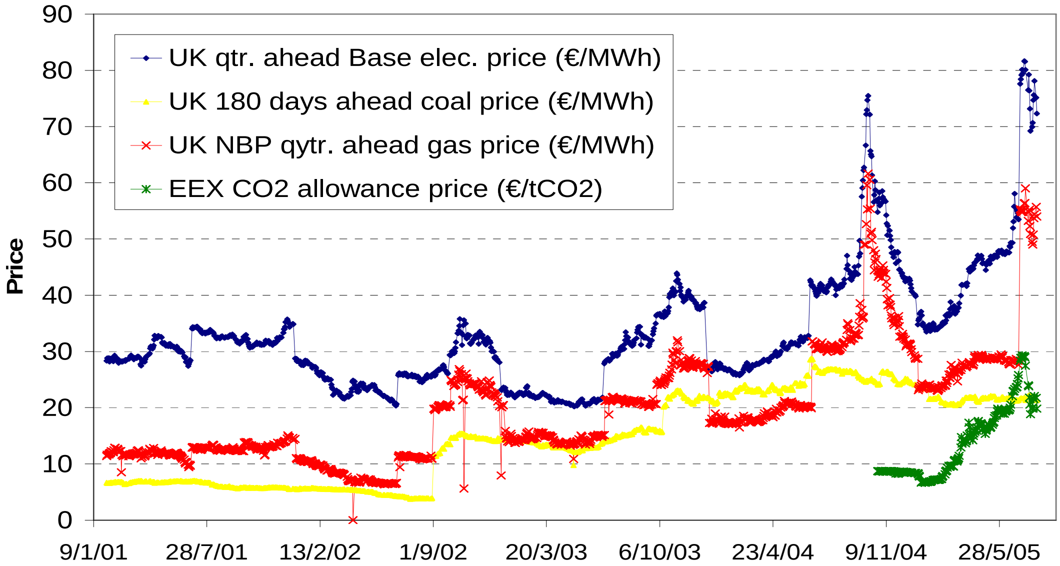


Figure 19 shows that daily forward prices for electricity and gas exhibit a strong seasonality pattern, with 'regime switches' corresponding to the transition from summer to winter periods. Besides, while electricity and gas prices remained fairly stable from 2001 to the summer 2003, they have been increasing since. Forward electricity and gas winter prices in particular have reached in 2004 and 2005 very high levels. Forward coal prices are subject to less seasonality effect, and have also substantially increased since 2001. *Table 20* shows the mean and standard deviation of these market prices.

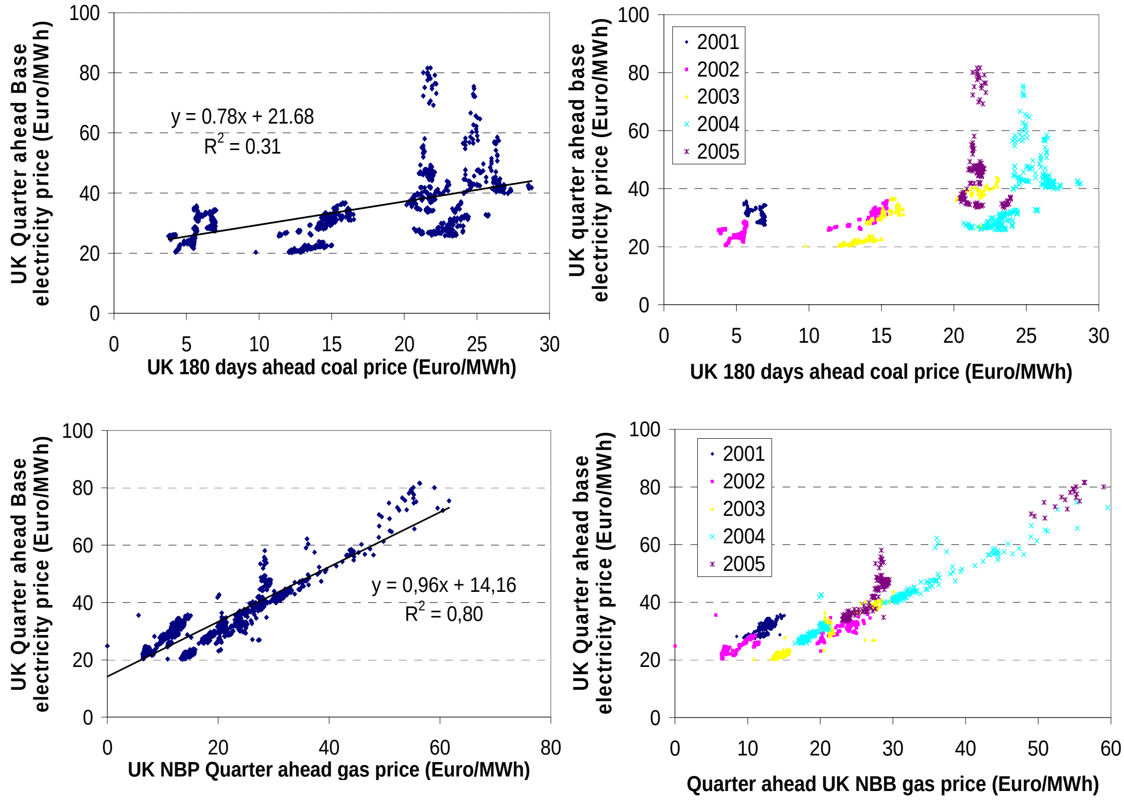
Table 20 - Empirical prices times series characteristics

Time series (Jan. 2001- Sept. 2005)	Unit	Mean	St. deviation
Quarter ahead UK base electricity prices	Euro/MWh	33.2	10.7
Quarter ahead UK peak electricity prices	Euro/MWh	41.9	13.2
180 days ahead UK coal prices	Euro/Mwh	14.9	7.7
Quarter ahead NBP gas prices	Euro/Mwh	19.9	10.0
EEX spot market CO2 prices	Euro/tCO2	13.59	6.25

Figure 19 suggests that there is a strong correlation between forward base electricity prices and forward gas prices, and a lower correlation between forward base electricity prices and forward gas prices. The linear regression showed on *Figure 21* confirms this intuition.

16 The reference of the daily quarter-ahead data on electricity base-load prices in the UK market from Platts is AAFPP00, and the reference for the daily quarter-ahead UK NBP gas prices from Platts is AACPV00, while the carbon prices data are from the EEX CO2 index.

Figure 21 - Linear regressions of forward daily UK electricity with forward daily gas prices and forward daily coal prices (2001-2005)



The correlation coefficients over the 5 years between these different market prices are shown in *Table 2*.

Table 22 shows, however, that these correlation patterns have been changing for coal from year to year. While the degree of correlation between forward base electricity prices and forward gas prices has remained high and stable in the British market from 2001 to 20005, the degree of correlation between forward electricity prices and forward coal prices has changed dramatically, with negative correlation in 2001 and 2005, and positive correlation from 2002 to 2004.

Table 22 - Yearly correlation of forward electricity prices with gas, coal, and CO_2 prices

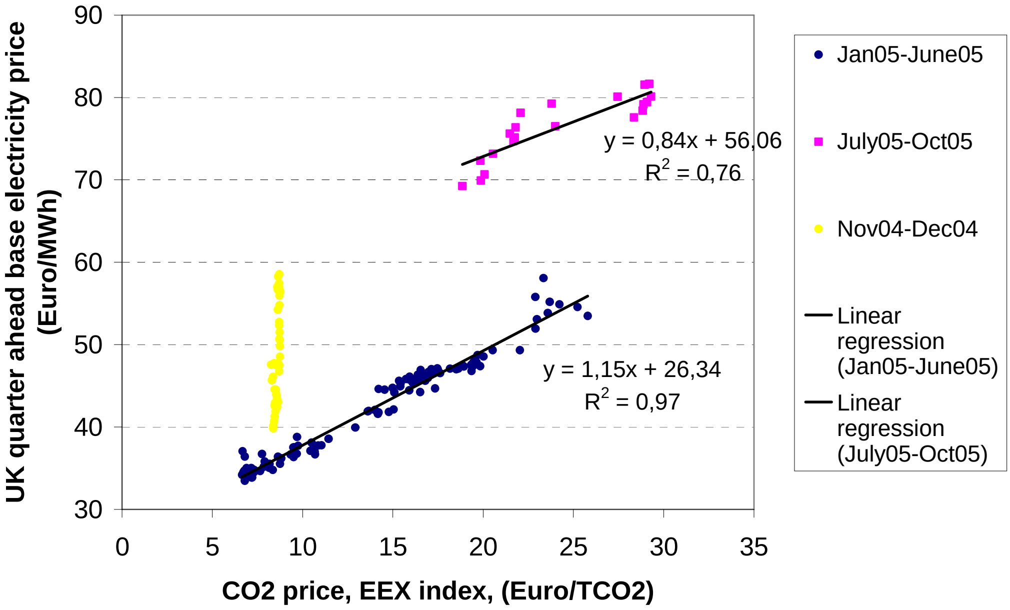
Correlation with quarter ahead UK base electricity prices	2001	2002	2003	2004	2005
180 days ahead UK Coal prices	-0,43	0,80	0,89	0,58	-0,03
Quarter ahead gas NBP prices	0,68	0,85	0,96	0,98	0,96
EEX CO2 allowance price	-	-	-	-	0,73

The correlation between fuel and electricity prices is the result of complex set of phenomenon, including the fuel used by the plants which have the highest marginal cots of production and are therefore clearing the market, but also other factors such as the terms and duration of fuel procurement contracts, the operational despatch strategies of electric companies holding portfolios of diverse generation technologies, and the behaviour of traders on electricity and fuel markets.

From 2001 to 2005, gas-fired plants have often been the marginal price setting plants in the British electricity market, which explains partly the very strong correlation between base electricity and gas prices. *Table 22* indicates that the correlation between coal and base electricity prices in 2001 and 2005 has been much less significant than in previous years. In 2005, the large increase in gas prices and the higher than expected price of the CO_2 allowances have brought much risk in the market.

Figure 23 looks in detail at the correlation between UK base electricity prices and the price of CO_2 allowances since November 2004. Three different regimes can clearly be distinguished: from November 2004 until the actual launch of the EUTS in January 2005, there was much risk on country allowances and the fluctuations of the CO_2 allowance price were not correlated with electricity prices. From the start of the EUTS in January 2005 until June 2005, and from July 2005 to October 2005, the correlation between forward base electricity prices and CO_2 allowance prices has been strong and similar during the two periods, the shift upward reflecting the seasonal effect of electricity prices.

Figure 23 - Linear regressions of daily forward UK base electricity and CO_2 prices (2004-2005)



9. Appendix 3: Assumptions and Limitations Affecting the Application of Mean-Variance Techniques to Generating Portfolios[17]

The application of mean-variance Markowitz Portfolio theory, originally developed for financial assets, to the creation of optimal portfolios of generating asset rests on a set of explicit and implicit assumptions and limitations:

1. MVP theory uses past volatility as a guide to the future. Following Stirling's (1998) distinction between 'risk', 'uncertainty', and 'ignorance', our focus is on (probabilistic) total risk, which will not reflect possible future 'surprise' events, which could cause major discontinuities to the electricity system but cannot be captured by a probabilistic approach.
2. The MVP model is based on the assumption that securities are infinitely divisible. The lumpiness of generation capacity additions is therefore an issue, but the application of MVP theory to generation portfolios can be justified when considering large companies or national generating portfolios (Awerbuch and Berger, 2003).
3. MVP theory assumes that the holding period returns are normally distributed. This is the reason why we model fuel, CO_2 and electricity price risk using normal distributions in our model. The Central Limit Theorem indicates that the NPVs distribution obtained in our Monte Carlo simulations should as a consequence be normally distributed. The limitations of our model rest therefore on the assumption that fuel, CO_2, and electricity prices are actually normally distributed. See e.g. Geman (2005) for a thorough discussion of commodity price modelling.
4. MVP theory relies on the assumption that assets are perfectly fungible: their value at any point in time must depend only on the amount, timing and certainty of expected cash flows. This may not always hold for generating assets where issues such as location and fuel availability may affect selection for various reasons (Awerbuch and Berger, 2003).
5. Financial returns generally reflect a benefit divided by an input, where both are dollar-dimensioned: i.e. 'dollars-returned/dollars invested'. The financial return measure is therefore dimensionless, a property that does not hold for our expected NPV return measure.
6. Transition costs from the actual to a future portfolio, as well decommissioning and salvage costs are not included in the current model formulation. This can be justified as long as we focus on new investment portfolios.
7. Generator owners tend to buy fuel through spot purchases and various contracts. We assume that gas and electricity are bought and sold on spot markets, or through contracts indexed on the spot market price. We therefore are likely to overestimate the fuel and electricity price risk. The focus is on the UK market. Times series of daily UK forward base and peak-load electricity prices, daily forward gas and coal prices from January 2001 to August 2005, and daily European CO_2 allowances prices from October 2004 to August 2005 were used to calculate standard deviation and correlation estimates (see Appendix for a detailed study of these time series).

17 This appendix draws heavily on Awerbuch and Berger (2003).

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