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1. INTRODUCTION

In recent years, declining domestic gas production and the escalation of foreign imports have raised concerns over British energy security. Since the turn of the century gross domestic production has fallen by 64% to the lowest level since 1984, whilst 2012 imports were 21 times greater than in 2000[1]. The trend does not seem to be slowing; the Chief Executive of British utility company Centrica recently warned that the UK will source 70% of its gas from imports by the year 2020. This trend has invoked considerable debate within the government and industry. Doubts remain, however, over the appropriate solution.

As fuel costs have risen, carbon prices have moved in the opposite direction. Since peaking in January 2011 the price of a European Union Allowance (EUA), which permits the emission of one tonne of CO_2, has fallen by 46%. Meanwhile, the EU has introduced a policy framework for the period up to 2030 to ensure the necessary conditions and targets are in place to tackle climate change. An important element of this plan is to increase the share of renewable energy to 27%. A question thus arises: which technologies should be present in an optimal portfolio of generation assets?

This paper focuses on investment incentives for private investors, considering fuel-mix diversification to be a way of mitigating exposure to uncertain electricity, fuel and carbon prices. Firstly, we discuss how electricity market liberalisation has affected investment incentives. We then introduce the case for using diversification as a risk-mitigation strategy under a Mean-Variance Portfolio theory framework. In so doing, we extend the approach developed by Roques *et al*. (2008) to assess the impact of adding renewable generation to the energy mix. This is useful in the context of liberalised energy markets and facilitates the consideration of electricity and carbon price risks in addition to fuel price risks examined by previous applications of MVP theory. We assess the impact of correlation between these variables. Roques *et al*. (2008) found that the strong correlation between electricity and gas prices reduces the incentive to diversify away from CCGT into coal or nuclear assets. This appears concerning given the potential benefits of fuel-mix diversification. We question whether this is still the case today, and whether the inclusion of renewable energy alters the outcome.

The implications of this study are extensive as investment decisions are both long-term and capital intensive. At the same time, the government is responsible for achieving a socially optimal fuel mix. Therefore, it is necessary to identify mechanisms that align the interests of electricity generators with those of the government, particularly given that a significant proportion of installed capacity within the UK is scheduled to go offline over the next decade.

The next section reviews the previous studies on this topic. Section 3 discusses Mean-Variance Portfolio Theory and optimal portfolios in the context of a liberalized electricity sector. Section 4 presents the results and their analysis of them. Section 5 concludes this paper.

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[1] Source: the Department of Energy and Climate Change, 2013: https://www.gov.uk/oil-and-gas-uk-field-data

2. PREVIOUS STUDIES

2.1 Diversification of technologies

Traditionally, the UK power sector consisted of vertically integrated, state-owned utilities that were involved in all segments of the value chain: generation, transmission, distribution and supply. This was true of Scotland and Northern Ireland, whereas the English and Welsh markets had a slightly more specific structure in which generation and transmission were the responsibility of the Central Electricity Generating Board (CEGB) whilst 12 regional Area Boards governed distribution and supply. These models shared important characteristics; there was no competition and consumers had no say in where they purchased their electricity.

After the electricity market was liberalised, the investment risk fell on producers, rather than consumers, as utilities could no longer shift costs directly to consumers. This meant that volatility and uncertainty in electricity, fuel and emission prices presented risks to private investors. Technology diversification offers a strategy for utilities to incorporate risk in their investment decisions (Roques *et al*., 2008). In contrast to a centrally planned system, liberalised electricity markets create an incentive to invest in capital-intensive technologies such as coal and nuclear (Averch and Johnson, 1962).

Stirling (1994) highlights that the revocation of European Community legislation preventing gas powered electricity generation was an example of a political decision aimed at diversifying the technology mix. Matthews and McGowan (1992) note that diversification must not be used to protect specific industries or firms. According to the UK Department of Energy and Climate Change (2012), approximately 20% of existing plants are scheduled to close down over the next decade and be replaced by technologies with intermittent supply of electricity, e.g. wind, or an inflexible supply, e.g. nuclear.

Stirling (1994) takes a quantitative diversity index from information theory to derive a value for the government's inclination to pay for a diverse UK energy supply mix. Grubb *et al*. (2006) extend this to investigate the impact of low carbon objectives on the diversity and security of the UK electricity system. Whereas Stirling applied only the Shannon-Weiner diversity index to the UK system to measure diversity, the latter also applied the Herfindahl-Hirschmann measure of concentration to the scenarios proposed by the DTI (2003) for the period from 2000 to 2050. They found that an increase in diversity would be observed under a 60% emissions target and that, importantly, insecurity declines as a result of reliance on multiple fuel sources. This study also finds that the reliability of wind generation does not have a significant impact on the first finding – i.e. low-carbon scenarios can maintain security of supply despite higher intermittency than conventional fuels. This casts doubt over a whole body of literature that suggests the contribution of renewable energy to the UK fuel mix is inhibited by concerns over its reliability (Spiecker and Weber, 2014; Trainer, 2013; Röpke, 2013).

It is important to distinguish between an individual firm and the industry in which it operates. Some diversification benefits discussed hereafter will be more prominent when isolating a particular company and some become more prominent when examining the power sector as a whole. However, this paper intends to analyse optimal generation portfolios for a utility that acts as a proxy for the sector and as such, assumes that all firms in the sector are affected in the same way.

Roques (2008) points to a disparity between what is likely to happen in the short run and what is likely to happen in the long run. He asserts that in the short run diversification offers a natural hedge against unexpected shocks that could increase the cost or decrease the quantity of available fuel, maintaining that it is also necessary to diversify between geographical sources of imports. Coal is traded internationally but gas tends to be available from fewer locations, attributing greater import risk to each exporting nation. In the long run greater fuel mix diversification reduces the macroeconomic impact of high fossil fuel prices (Roques, 2008).

Gas prices are usually correlated with oil prices, because of explicit indexation of prices and competition between the two fuels. However, even in Britain where formal links to oil prices are present in few gas supply contracts, gas prices are generally aligned with oil prices as a result of fuel switching (IEA, 2006). Consequently, a higher dependence on combined cycle gas turbine (CCGT) generation should increase the sensitivity of the economy, and the power sector, to fossil fuel price shocks.

2.2 Risk management in the power market

The range of financial risk management tools available to power generators is not wide. Roques (2008) suggests that this may have an impact on the technologies that they employ, as some contain a higher level of 'self-hedging' than others. CCGT plants, for example, due to the strong correlation between gas and electricity prices in the UK, generate stable revenues.

The DOE (2002), cited in Roques *et al*. (2006, p. 6), points out that when the electricity market was liberalised analysts envisaged a boom in electricity derivatives markets. By the start of 2002, however, the three major US exchanges trading electricity futures contracts had de-listed them and suspended trading, causing uncertainty over their future. In the case of the power market, this is not particularly informative as the Over-The-Counter (OTC) market is the primary channel through which power is traded (ECORYS, 2008). Indeed, there is an array of options if one considers forward contracts, swaps and plain vanilla options.

A common electricity derivative is a forward contract, which obliges the buyer to purchase and the seller to supply a fixed quantity of electricity at a certain price (the forward price), at a pre-specified time in the future. Due to the nature of electricity use, this type of contract differs slightly from forward contracts on other commodities as delivery of electricity spans a period of time. Thus, there are peak, off-peak and 'around the clock' forwards depending on when the electricity is delivered (Deng and Oren, 2006). UK electricity market reform incorporates forward contracts by using a Feed-in Tariff (FiT) with Contracts-for-Difference

(CfD), whereby the generator is entitled to the designated strike price, a measure of the incurred cost of investing in low-carbon technologies less what is defined as a 'reference price', a measure of the wholesale price of electricity (DECC, 2013b). The CfD mechanism allows generators to stabilise income at a predetermined level across the contract period (DECC, 2011), thereby alleviating volatility of cash flows and reducing risk.

Forward contracts in electricity markets are well documented. The 2000 electricity crisis in California shows the risk of spot markets. Utilities were not allowed to use forward contracts to hedge against the risk of rising wholesale power prices. When prices began to rise a retail rate freeze was implemented, meaning utilities were buying wholesale power at high prices and having to sell it to consumers at fixed low prices, leaving them insolvent (Joskow, 2001). Ausubel and Cramton (2010) argue that forward markets solve some of the problems and protect the solvency of utilities. Anderson and Hu (2008) make a similar argument, building on previous literature which explains how generators can exercise market power and attain higher prices. These models assume that the contract price is equal to an expectation of the spot market price, within a rational expectations and zero arbitrage framework (Newbery, 1998; Green, 1999).

Electricity futures are similar to forward contracts but are marked to market daily meaning payment is made over the period of the contract. Furthermore, rather than often being a custom contract arranged between the buyer and the seller, futures are more homogeneous and are exclusively traded on exchanges (DOE, 2002). Electricity price swaps are another form of electricity derivative that encompass a predetermined quantity of power which is linked to the spot price either at the generator's location or the purchaser's location, making it possible to secure a fixed price at a separate location to the point of delivery specified under a futures contract. If a consumer cannot predict how much electricity they will use, option contracts provide the right, without an obligation, to acquire a specified quantity of electricity at a certain price in the future. In the electricity industry, spark spreads are options created to protect against disparities between the price of electricity and the cost of generating it.

Whilst these products are all used to some extent, several authors have noted the existence of barriers to their wider use. Weron (2000), for example, argues that the electricity market is unique because electricity cannot be stored and therefore derivatives cannot be priced using the usual arbitrage models; the cost of carry (insurance, storage and wastage costs) for electricity is effectively infinite so the formula for pricing a forward contract[2] breaks down.

These findings suggest that the use of derivatives to diversify risk exposures remains challenging in the absence of a better understanding of industry specifics and more customised instruments. A few products that are not based on the underlying electricity spot price have already materialised in the form of weather derivatives, emissions permits and insurance contracts so it will be interesting to see how they develop.

2. [2] $K=U(1+rT)+C$ where K is the fixed price of electricity, U is the current price of electricity, r is the risk-free interest rate, T is the time period of the contract and C is the cost of carry (insurance, storage, obsolescence and spoilage).

2.3 Mean-Variance Portfolio (MVP) Theory

Markowitz (1952) first conceived Mean-Variance Portfolio theory. He refuted the claim that investors should maximise the value of future returns, given a particular discount rate, on the basis that without market imperfections this would imply that there is no diversified portfolio that is preferable to all non-diversified portfolios. He also challenged the assertion that due to the law of large numbers, which insures that the true yield of the portfolio and the expected yield will be broadly the same (Williams, 1938), there exists a rule suggesting investors should diversify their holdings, while maximising their expected return, by holding those securities that yield the maximum expected return. Markowitz contends that when applied to a portfolio of securities, the assumption that the law of large numbers holds true is unacceptable as the intercorrelation between security returns is high, meaning diversification can only partially eradicate variance. Therefore, a portfolio that maximises return is not automatically the portfolio that minimises the variance and it becomes possible for an investor to achieve higher expected returns by accepting variance or to forego variance by targeting lower expected returns. The result is that there exists an 'efficient frontier' along which any combination of assets maximises returns for a given level of risk.

Whilst this theory was originally intended for financial securities, there have been several applications to power generation assets to ascertain an optimal portfolio for a firm or a country. The assumptions required to perform this kind of analysis are discussed in the methodology section of this paper. The application of this theory to the power sector implies it is imperative that we assess alternative portfolios of assets as opposed to alternative individual assets to determine the value of electricity generation assets. Bar-Lev and Katz (1976) produced one of the first studies when they applied MVP on a region-by-region basis to the US electricity industry. Comparing their results to observations within the sector, they found that whilst utilities seemed to have efficiently diversified their portfolios, the combinations of assets they held was characterised by high rates of risk and return. They attributed this to the 'cost-plus' regulation at the time. Under such a regime, utilities cannot vary their prices without consent from the regulatory commission. The authors argue that a utility will fare better if it can prove that it bought a cheap combination of fuels, as the regulator pays little attention to risk and instead emphasises the return, leading a usually conservative sector of the economy to conduct risky behavior.

Awerbuch and Berger (2003) assess the usefulness of MVP theory for developing efficient frontiers of generation assets in the European Union to meet both diversification and energy security objectives. Building on Awerbuch's work, different models are presented that incorporate the risk associated with fuel, construction periods and operation and maintenance costs. The reason this technological distinction improves the analysis is that it allows different cost and risk estimates to be produced for existing versus new technologies. The common factor in these models is that technologies with fixed costs, e.g. renewables, are necessary for an efficient portfolio. We explore this to establish whether the same is true of the UK. Furthermore, Awerbuch (2006) reiterates the importance of renewables using case studies from the EU, the

US and Mexico to illustrate that adding more costly technologies can lower the generating cost of the portfolio if one evaluates different resource portfolios instead of individual resources. DeLaquil *et al*. (2005) take a similar approach and focus on the commonwealth of Virginia to assess the benefits of different portfolios under the Renewable Portfolio Standard legislation that was being considered at the time. Their results mirror those of previous studies, showing that portfolios containing renewables "significantly reduce electricity cost-risk while increasing cost only slightly".

Since investors do not evaluate investment opportunities in terms of production costs, but in terms of risk and return, it is not appropriate to use a cost-based model such as the one used by Awerbuch and Berger (2003) in liberalised electricity markets (Roques *et al*., 2008). Whereas these studies estimate historic cost risk per technology using historic fuel cost variations, the introduction of electricity price risk and, in the EU, CO_2 price risk obscures the optimal portfolio calculation. If the electricity price is regulated and set at the levelised cost of production, the returns and intercorrelation of returns between different technologies can be derived directly from the magnitude and intercorrelation of the fuel costs used by the different types of electricity generator. In a liberalised environment where prices are determined by supply and demand the price risks need to be accounted for. This consideration will be factored into the approach taken in the following section.

In summary, a defining feature of the power market is the lack of risk mitigation tools. DECC (2013b) explains how electricity market reform has incorporated a type of forward contract through a Feed in Tariff with Contracts-for-Difference, allowing generators to limit the volatility of their earnings. Ausubel and Cramton (2010) and Anderson and Hu (2008) argue that forward contracts are beneficial as they encourage investment in new resources, mitigate the risk of high prices during shortages and eliminate the incentive for market participants to distort bids. Whilst other derivatives exist, such as futures contracts, Weron (2000) points out that complexity limits their use. Therefore, the extent to which they constitute an alternative for diversification is questionable. Awerbuch (2006) showed that adding more expensive technologies can lower the cost of the overall portfolio if one considers entire resource portfolios instead of individual resources. Nevertheless, a different approach is required since cost-plus regulation is no longer in use. Liberalisation makes it necessary to account for electricity and CO_2 price uncertainty and assess portfolios in terms of risk and return rather than production costs. Hence, a study of this type is informative.

3. MVP Theory and Optimal Portfolio in a Liberalised Power Sector

Cost-based studies typically use estimates of the levelised cost of generating electricity, such as those presented by the EIA (2013), which corresponds to the cost per kilowatt hour of constructing and running a power plant for an assumed number of years. Hence, an examination of prior fuel cost fluctuations facilitates a simple estimation of the cost risk associated with each technology, and one needs only a time series of average annual fuel prices and their cross-correlation (Roques *et al*., 2008). With this approach the returns and the cross-correlation between returns from different technologies can be deduced from the fuel costs and their respective correlations.

However, introducing the price risk associated with electricity and CO_2 permits calls for a more sophisticated approach and for using the correlation between electricity generation fuels (gas, coal and uranium) and CO_2 prices. The correlation between investment returns for different technologies cannot be identified directly, meaning an extra step is required in the form of a Monte Carlo simulation which generates an appropriate proxy and allows us to model the distribution of returns.

Whilst different measures of return can be used, we choose the expected Net Present Value per megawatt of capacity. Similarly, we define the risk of an investment as the standard deviation of the expected NPV that it generates. Finally, the correlation between returns of different technologies is defined as the correlation between their NPVs.

Following Roques *et al*. (2008) we consider three conventional technologies: gas, coal and nuclear (more specifically Combined Cycle Gas Turbine (CCGT), Integrated Gasification Combined Cycle (IGCC) and Advanced Gas-Cooled reactor (AGC) technology). However, we extend their research by considering the addition of renewable energy to the generation mix. Introducing multiple renewable technologies is outside the scope of this paper. Instead, we adopt a similar approach to Awerbuch and Berger (2003) by using wind technology as a proxy for a varied set of renewable sources. This is justifiable given that it is the only renewable option mature enough to significantly contribute to the resource mix in the short term (Grubb *et al*., 2008).

The optimal technology mix of is obtained using the following steps:

- A discounted cash flow valuation model is built for each technology
- The standard deviation and cross-correlations of electricity prices, carbon prices and fuel prices are obtained from historical time series data
- A Monte Carlo simulation is used to estimate the distribution of returns from investments in each technology. Electricity, CO_2 and fuel prices are assumed to be normally distributed random variables and their respective standard deviations and cross-correlations are calibrated using the historical time series data
- A regression of 5,000 simulations of the returns from each technology is run to calculate their correlation coefficients
- MVP theory is applied to determine the risks and returns of different generation portfolios. The correlation coefficients are provided by the previous step.

3.1 Model Inputs

The model used for this study uses the most accurate parameters available. For example, the average load factors were provided by the DECC (2013a) and the construction period and overnight costs[3] have been extracted from a RAE (2009) study. Furthermore, fixed and variable operating cost data were made available by the DECC (2010). The cost of emitting CO_2 into the atmosphere is represented by the price of purchasing a EUA. The financing parameters are somewhat simplified; the marginal tax rate in the UK is 30% and we assume the weighted average cost of capital (WACC) to be 8%[4]. The plant life durations of 20 years for wind, 30 years for CCGT and coal and 40 years for nuclear are consistent with the DECC (2010) report mentioned above. Finally, we assume that all plants begin operation in 2009. The parameters used in the discounted cash flow for each technology relate to the years 2009-2013. *Table 1* summarizes the model inputs.

In order to identify the optimal mix of technologies we first determine the distribution of NPVs of an investment in each technology. The NPV is derived from the 'free cash flow' - that which is left over after all projects with a positive return have been funded (Lehn and Poulsen, 1989) - which in turn depends on cost and revenue streams. For all of the technologies considered here, revenues stem largely from the available electricity price and we assume the operating costs to be constant, and then adjusting them in line with inflation.

Whilst costs and revenues cannot be estimated with precision, uncertainties have been limited to electricity prices, fuel costs and CO_2 allowance prices. We assume that fuel and CO_2 allowances are traded on spot markets or via forward contracts linked to the spot market price and are therefore subject to volatility. These uncertain variables are modelled as normally distributed random variables. It must be noted that this is a conjecture as they are unlikely to exhibit normal distributions, however in order to apply the MVP theory it is a necessary step (Copeland and Weston, 1988).

In order to simulate the NPV, or returns from each technology, we require data on electricity prices, fuel costs and CO_2 allowances. From this we derive the mean values, the standard deviations and the cross-correlations. Time series' of daily one-month forward gas, coal and base load electricity prices, as well as daily European Union allowance prices were examined. Average monthly uranium prices were provided by UxC and include enrichment and conversion costs. There are no available data on fabrication costs, however the WNA (2008) estimates their proportion of total fuel costs to be 13% so this assumption is used to arrive at a predicted cost. As uranium is replaced every 18-36 months, we assume that a fuel cost is incurred every other year.

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[3] 'Overnight cost' is the capital cost of constructing a power plant, exclusive of financing costs (DECC, 2010). In this instance, the overnight cost for a nuclear plant includes a provision for decommissioning costs.
[4] This is consistent with information provided by the Power, Utilities & Renewable Energy investment banking advisory team at Citigroup.

Parameters	Unit	CCGT	Coal	Nuclear	Wind
Technical Parameters					
Generating Capacity	*MW*	1000			
Load Factor	*%*	30	57	71	27
Carbon Intensity	*kgC / mmBTU*	116	260	0	0
Plant Life	*years*	30	30	40	24
Cost Parameters					
Overnight Cost	*£/kW*	718	1964	2919	1520
Fuel Costs	*£ / mmBTU*	See parameters			
Fixed Operating Costs	*£ / kW/ year*	26	51.5	61.5	34.2
Variable Operating Costs	*£ / MWh / year*	2.2	2.5	1.8	0
Financing Parameters					
Projected Inflation Rate	*%*	2.2			
Discount rate	*%*	8			
Corporate tax rate	*%*	30			
Regulatory Parameters					
Carbon tax	*£ / tC*	See parameters			
Revenues					
Electricity Price	*£ / MWh*	See parameters			

Table 1: DCF Model Inputs

Source: DECC (2013a), RAE (2009), DECC (2010)

The period considered is the past 5 years, consistent with Roques et al. (2008) and Bonacina (2013), as this analysis is focused on assessing up-to-date diversification incentives and a longer time period would necessitate alterations to reflect changes in the fuel mix. The correlation coefficients between electricity, fuel and CO_2 prices are presented in Table 2. The parameters used in the Monte Carlo simulation are presented in Table 3.

Correlation Coefficient	Base Electricity Price	Gas Price	Coal Price	Uranium Price	CO_2 Price
Base Electricity Price	1.00				
Gas Price	0.91	1.00			
Coal Price	0.58	0.48	1.00		
Uranium Price	-0.43	-0.40	0.42	1.00	
CO_2 Price	-0.41	-0.65	0.18	0.68	1.00

Table 2: Price correlation coefficients, 2009-2013

Source: Authors' own calculations

Normal Distribution Parameters	Technology	Mean	Standard Deviation
Cost Parameters			
Fuel cost (£/mmBTU)	**Nuclear**	6.77	1.12
	CCGT	6.71	1.45
	Coal	1.81	0.39
	Wind	0.00	0.00
Carbon tax (£/tC)	**All**	10.51	4.13
Revenue			
Electricity price (£/MWh)	**All**	50.19	6.55

Table 3: Risk Distribution Inputs – Monte Carlo simulation

Source: Authors' own calculations

Normal distributions are used to model fuel costs, carbon prices and electricity prices using these distribution parameters and coefficients of correlation. The mean values of the distributions are based on 2013 prices. The following section will explore the fluctuations in electricity prices, fuel prices and CO_2 prices. This should provide a context underlying the results generated by this model, as the correlation between these different variables is important to accurately assess diversification incentives.

3.2 Electricity, Fuel and CO_2 Costs in the UK

Electricity, fuel and CO_2 price data were retrieved from Bloomberg[5] whilst UxC provided uranium price data. All fuel costs are converted into pounds per megawatt-hour. *Figure 1* shows daily month-ahead electricity prices, gas prices and coal prices, daily European Union CO_2 allowance prices and average monthly uranium prices for 2009-2013. Electricity and gas prices fell sharply at the start of 2009, whilst CO_2, uranium and coal prices fell to a lesser extent due to the recession: Q2 2008 was the first quarter in which the UK economy contracted, whilst in Q4 2008 and Q1 2009 growth declined at the fastest rate; 2.08 and 2.3% respectively (Bank of England, 2010). Depressed economic activity and low stock market contributed to lower demand for electricity, fuel and CO_2. Later electricity and fuel prices began to recover along with economic activity. CO_2 prices fell into another downward trend towards the latter half of 2011. This was partly due to concerns about the Greek economy and a vote to allow the European Commission to distribute 300 million additional permits to the European Investment Bank (EIB), to be sold into the market. After 2011, the carbon market remained depressed due to oversupply of allowances. The reason that uranium prices peaked in 2011 and continued to fall was the Fukushima disaster in March 2011 and doubts over the safety of nuclear reactors.

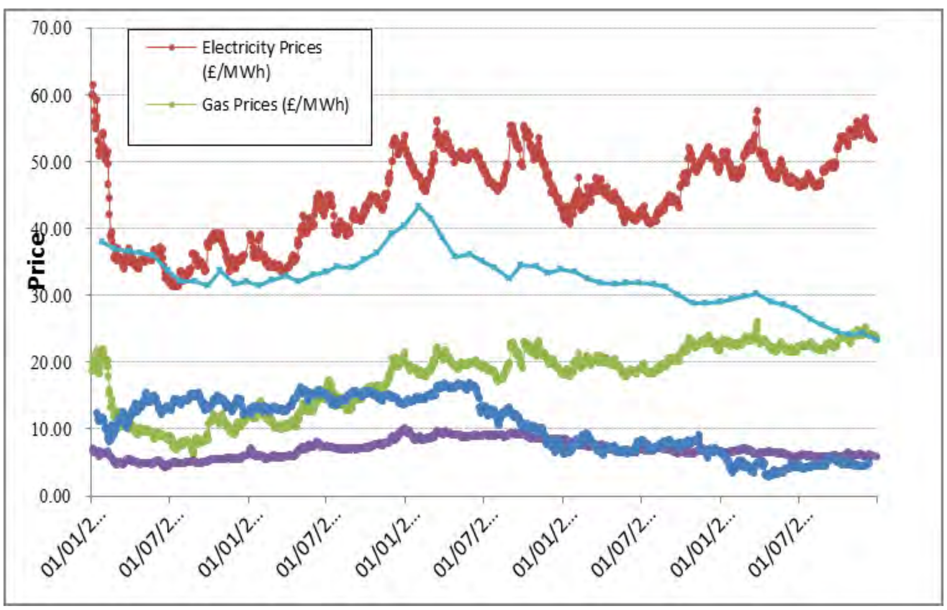

Figure 1: Daily one month forward electricity and fuel prices and EUA CO_2 prices (2009-2013)

Source: Bloomberg

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[5] The Bloomberg tickers are as follows: Electricity – ELUB1MON, Gas – NBPG1MON, Coal – API21MON, CO_2 – EEXX02EA / EEXX03EA.

A strong correlation between electricity and gas prices is also evident from the chart. This is confirmed by *Figures 2* and *3*, which present linear regressions of gas and coal prices against electricity prices. Uranium price data were only available on a monthly basis, rather than daily, meaning no such comparison could be made.

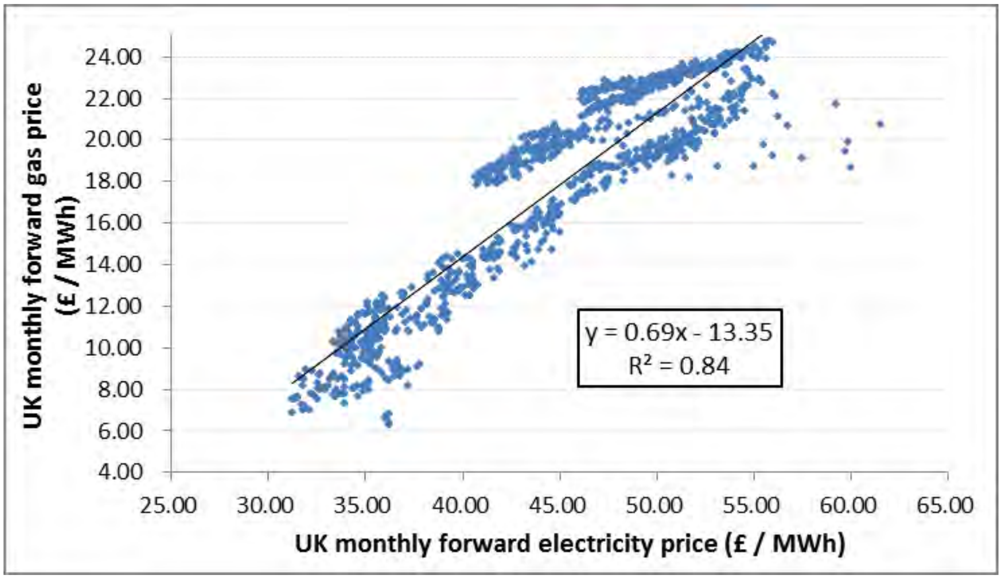


Figure 2: Correlation between daily forward electricity and gas prices (2009-2013)

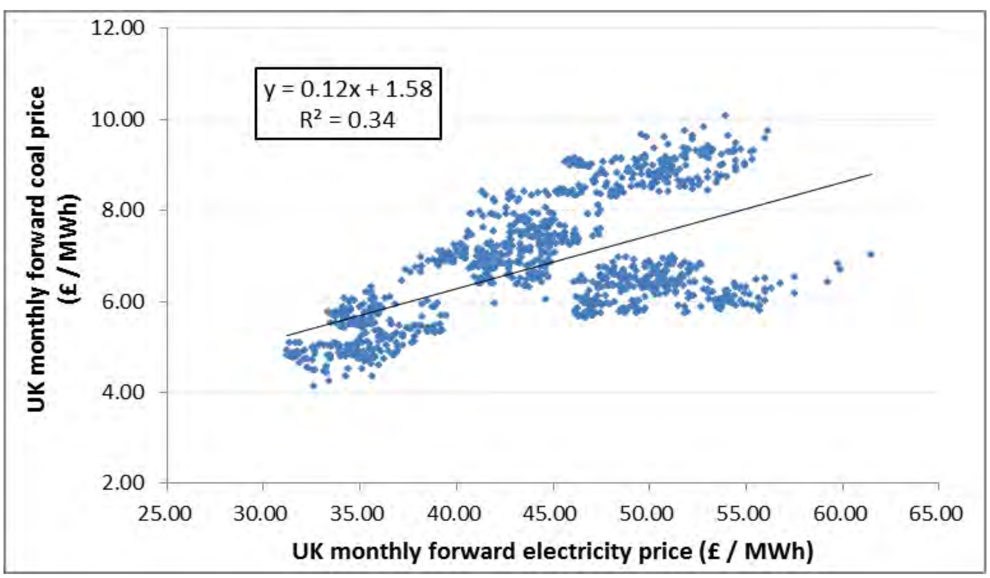


Figure 3: Correlation between daily forward electricity and coal prices (2009-2013)

Whilst the correlation coefficients over the entire 5-year period are displayed in *Table 2*, *Table 4* displays the annual correlation coefficients between electricity prices with gas, coal, uranium and CO_2 prices.

Correlation with UK base load electricity prices	2009	2010	2011	2012	2013
One-month forward gas price	0.94	0.98	0.82	0.98	0.93
One-month forward coal price	0.84	0.96	0.55	-0.27	0.11
Monthly uranium price	0.50	0.77	-0.06	-0.79	-0.27
CO2 Price	-0.46	0.57	0.38	0.03	0.25

Table 4: Correlation between base load electricity price and gas, coal, uranium and CO2 prices (2009-2013)

Source: Authors' own calculations

The correlation between electricity and gas prices has been stable across the 5 years, however all other sets of correlations experience significant variation, fluctuating between positive and negative relationships.

The relationship between electricity and fuel prices is complex. The EIA (2014) notes that natural gas has a strong influence on the price of power but that decomposing this link into different explanatory factors is challenging. Nevertheless, the report suggests that the share of power generation coming from gas plants, the cost of transmission and distribution systems and the proportion of power purchased directly from wholesale markets are all relevant. Roques *et al*. (2008) point out that the fuel used by the marginal price-setting plant can also affect the correlation between fuel and electricity prices. This is consistent with the data used in this study since gas is often the marginal price setting plant (DECC, 2012a) and gas prices have the highest correlation coefficient with electricity prices.

The correlation between coal and electricity prices is strong throughout the period 2009-2011 but falls sharply in 2012 and 2013. *Figure 4* shows the correlation between these two variables.

After peaking in the last quarter of 2011, both electricity prices and coal prices begin to decline. Unlike electricity prices, which regain an upward trajectory in the 3rd quarter of 2012, coal prices continue to fall throughout 2013. The EIA (2013) suggests that this is due to the relative competitiveness of US gas-fired production following the emergence of the shale revolution. Gas prices in the US dropped so low in 2012 that gas plants became more economical than coal plants, meaning the balance of power generation shifted towards gas technologies. This also had an impact in the UK because the excess coal no longer consumed by the US was exported and the abundance of coal depressed global prices.

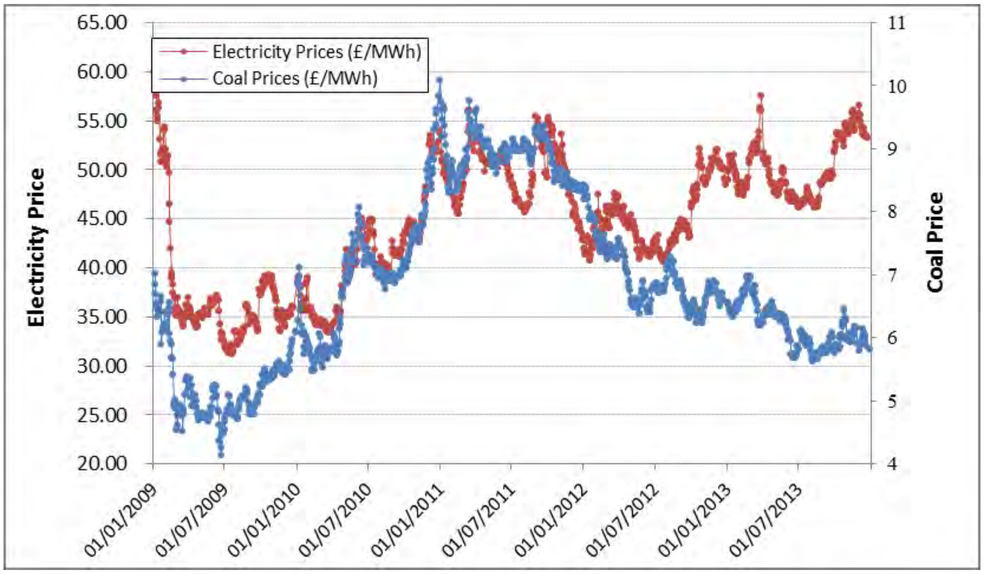


Figure 4: Time series comparison, coal and electricity prices (2009 – 2013)

Source: Bloomberg

4. RESULTS AND ANALYSIS

4.1 Simulation Results

Having examined the underlying relationships between the different variables in the model, this section presents the results obtained from the Monte Carlo simulation. Investment returns were simulated for investments in the different technologies under three scenarios:

1. A hypothetical scenario whereby electricity, fuel and CO_2 prices are uncertain but completely independent of one another.
2. A scenario appropriate for the structure of today's electricity market whereby the price of electricity, fuel and CO_2 are uncertain and the correlation coefficients are equal to those displayed in *Table 2*.
3. A scenario whereby electricity markets are liberalised and the correlation coefficients between electricity, fuel and CO_2 are set equal to those in *Table 2*. Real electricity prices are held constant at the 2009 level to simulate the existence of a power purchase agreement established at the beginning of the plant's life, covering the entire life of the plant.[6]

Figures 5-7 show the distribution of returns from every fuel technology under each scenario. Note that we assume that plants cannot be mothballed or de-mothballed when the expected NPV falls below zero.

[6] The assumption that the power purchase agreement covers the entire life of the plant is to simplify the analysis. In reality the term may vary (Thumann and Woodroof, 2009).

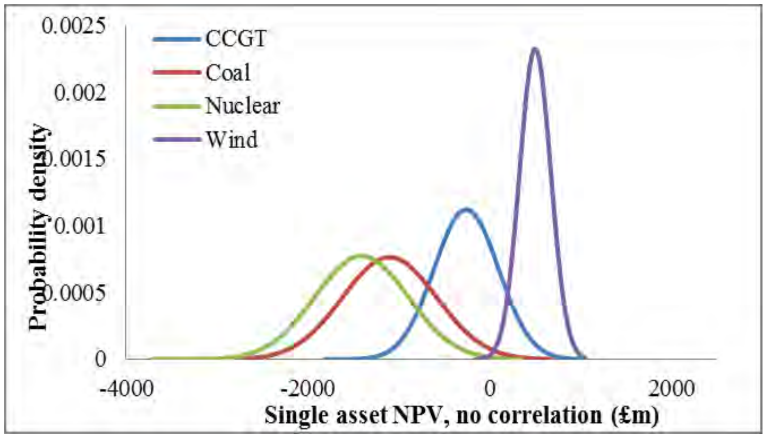


Figure 5: Distribution of asset returns - uncorrelated prices

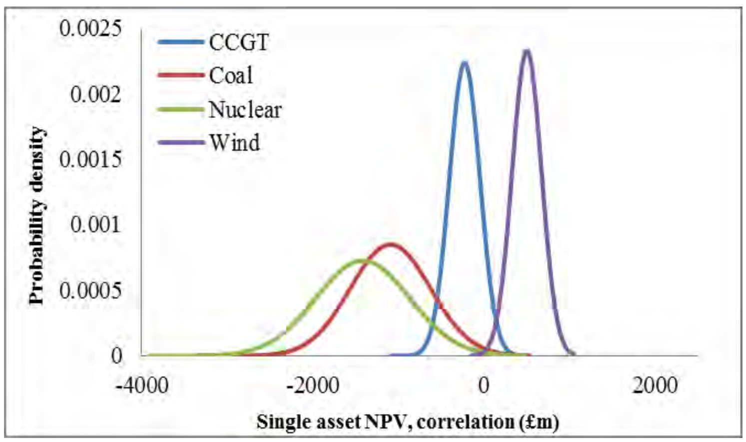


Figure 6: Distribution of asset returns - correlated prices

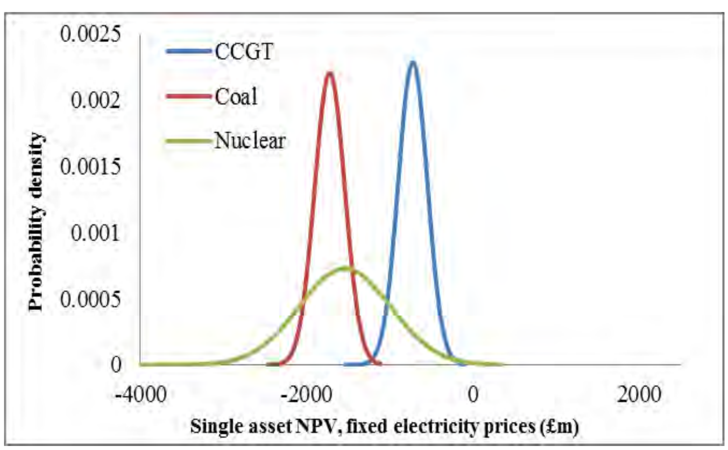


Figure 7: Distribution of asset returns – PPAs

Both the nuclear, and to a lesser extent the coal plant seem relatively unaffected by the liberalisation of electricity markets as they have similar expected NPVs under the two scenarios. *Table 5* displays the distribution statistics in more detail.

Scenario	**Independent electricity, fuel and CO_2 prices (Scenario 1)**				**Correlated fuel, electricity and CO_2 prices (Scenario 2)**			
Statistics	**CCGT**	**Coal**	**Nuclear**	**Wind**	**CCGT**	**Coal**	**Nuclear**	**Wind**
Mean	-255	-1099	-1408	503	-223	-1090	-1413	503
Standard deviation	355	521	514	171	179	469	549	171
Minimum	-1815	-3270	-3697	-145	-1088	-3361	-3911	-145
Maximum	1031	676	342	1052	384	527	469	1052
Range	2847	4396	4039	1197	1471	3889	4381	1197

Table 5: Returns distribution statistics by technology, £m

Source: Authors' own calculations

Comparing the distributions of the four categories of technology reveals larger discrepancies. Whilst the spread of coal and nuclear NPVs does not vary significantly between Scenarios 1 and 2, and they are in both cases the most risky assets, the spread of CCGT NPVs is narrower, indicating that gas assets are less risky in Scenario 2. This is intuitive since the correlation between electricity and gas prices is very high, meaning the technology is partially self-hedged and higher fuel prices are approximately matched by higher electricity prices. The distribution of the NPVs for wind remains unchanged between the scenarios since a wind generator does not incur fuel or CO_2 costs. The introduction of PPAs has the greatest influence on coal returns, dramatically reducing the spread. Wind is not included in this instance since fixed electricity prices eliminate uncertainty from the model.

4.2 MVP theory application

MVP theory states that a rational investor will seek to achieve the maximum possible return without exceeding her risk tolerance (Maginn *et al*., 2007). The efficient frontier is a graphical representation of all possible efficient portfolios and is one section of the 'minimum-variance frontier' (MVF), which plots all portfolios that minimise the variance of each given level of return. The MVF has a turning point that is known as the 'global minimum variance' (GMV), the left-most point of the curve, representing the portfolio with the lowest variance out of every minimum-variance portfolio as demonstrated in *Figure 8*. The efficient frontier consists of the section of the MVF that is above the GMV.

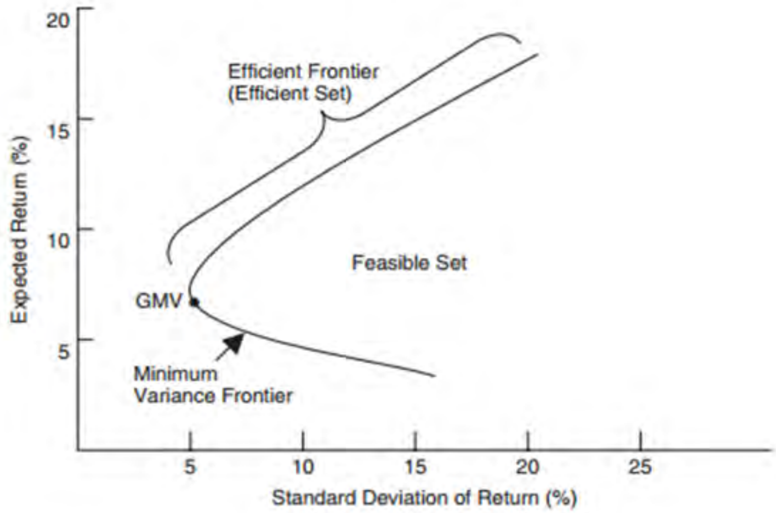


Figure 8: The Efficient Frontier

Source: Maginn *et al*. (2007)

MVP theory provides a framework to identify a range of efficient portfolios from which investors can choose, based on their risk preferences. In the case of a portfolio of two assets the following formulae can be used to calculate the risks and returns:

$$E(R_P) = X_A E(R_A) + X_B E(R_B)$$

That is, the expected return of portfolio P is the weighted average of the expected returns on the two assets, A and B, when they are held in proportions ⍰⍰ and ⍰⍰ respectively. The standard deviation of the portfolio can be written as:

$$\sigma_P = \sqrt{{X_A}^2{\sigma_A}^2 + {X_B}^2{\sigma_B}^2 + 2X_A X_B \sigma_A \sigma_B \sigma_{AB}}$$

rσ_{AB}epresents the correlation between the return from asset A and that from asset B.
In the case of a portfolio that consists of more than two assets the equivalent equation is as follows:

$$E(R_P) = \sum_{i=1}^{N} X_i E(R_i)$$

In other words the expected return of a portfolio P that consists of N assets is equal to the weighted average of the expected returns of the N assets when they are held in proportion X_i.The standard deviation of the portfolio is given by the following equation:

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

Where ρ_{ij} corresponds to the correlation between the returns of asset i and those of asset j.

4.3 Net present value correlations

For the application of MVP theory we require the return and risk of an investment in each technology. In this paper we use the expected net present value and the standard deviation of the net present value respectively. We also require the correlation between the returns of the different assets. These are displayed in *Table 6*. The correlation between the returns on different technologies is very low for every combination except CCGT and coal plants. This initial observation suggests that the addition of coal to a portfolio of CCGT assets will have an insignificant risk-reduction effect, whereas the addition of any of the other technologies to the same portfolio of gas assets should have a more noticeable impact.

Correlation of returns	CCGT/ Coal	CCGT/ Nuclear	CCGT/ Wind	Coal/ Nuclear	Coal/ Wind	Nuclear/ Wind
Uncorrelated elec/fuel/CO_2 prices	0.97	0.02	0.006	0.014	0.008	0.003
Correlated elec/fuel/CO2 prices	0.99	0.02	0.006	0.017	0.007	0.003

Table 6: Correlation coefficients between returns of different technologies

Source: Authors' own calculations

4.4 Optimal portfolio: two assets

Since CCGT represents the majority of modern generation technology built in the UK (Wright, 2006) we have analysed different combinations of two-asset portfolios on the basis that they always include CCGT technology. *Figure 9* displays the efficient frontiers for portfolios of CCGT and coal assets with varying degrees of hypothetical correlation. When the correlation coefficient is greater than 0.2 an efficient frontier does not exist because the returns of coal assets are both lower and more variable than those of CCGT assets. Therefore, if the returns on CCGT plants are strongly correlated with returns on coal plants, it would make little sense to complement a pure CCGT portfolio with riskier, lower return assets. If the correlation coefficient of the returns is less than 0.2 it is possible to reduce overall portfolio risk by adding coal assets. A correlation coefficient of -1 corresponds to a scenario in which returns move in perfectly opposite directions so that the assets achieve their highest and lowest level of returns under directly opposite market conditions. Hence, the 'portfolio effect' becomes gradually larger as we tend towards this point, at which it is possible to reduce the risk of the portfolio to zero. This portfolio would yield an expected NPV of around -£450m. The observed correlation, however, is 0.99, meaning we cannot achieve risk-reduction through diversification, and that no efficient frontier exists. Similar to *Figure 9*, *Figure 10* illustrates the efficient frontiers for a combination of CCGT and nuclear using a range of hypothetical correlation coefficients between returns.

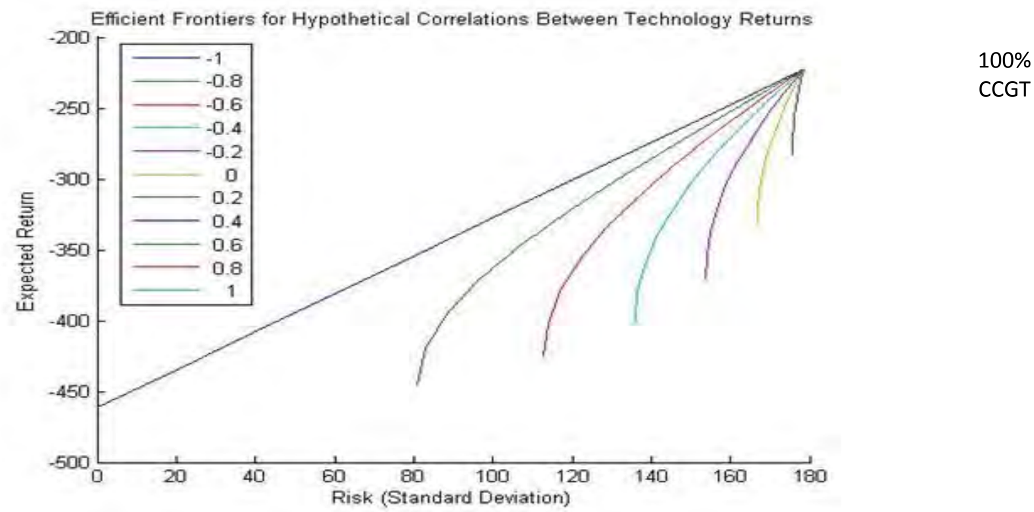


Figure 9: Efficient frontiers for portfolios of CCGT and coal – different hypothetical correlations, £m

Again, no efficient frontier exists beyond a correlation coefficient of 0.2. Additionally, the zero-risk portfolio has a slightly lower NPV of around -£500m, so if an investor must choose between the two technology combinations, assuming the correlation of returns for both is equal to -1, it is preferable to choose the former. This view changes when the observed correlation coefficient of 0.02 is recognised.

Figure 11 displays the efficient frontier of CCGT-nuclear portfolios. If an investor's risk tolerance is not high enough to warrant investing in a pure CCGT portfolio, she can reduce her risk by introducing nuclear assets.

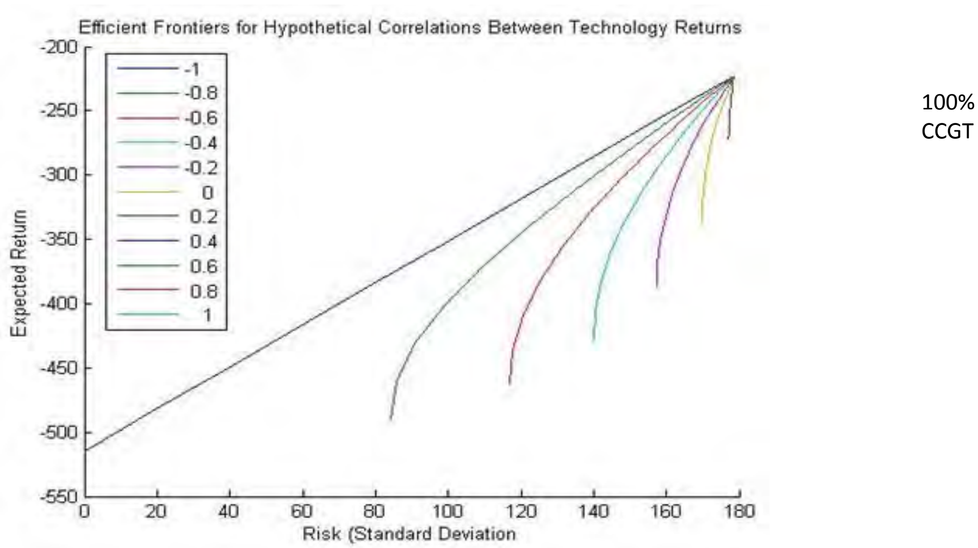


Figure 10: Efficient frontiers for portfolios of CCGT and nuclear – different hypothetical correlations, £m

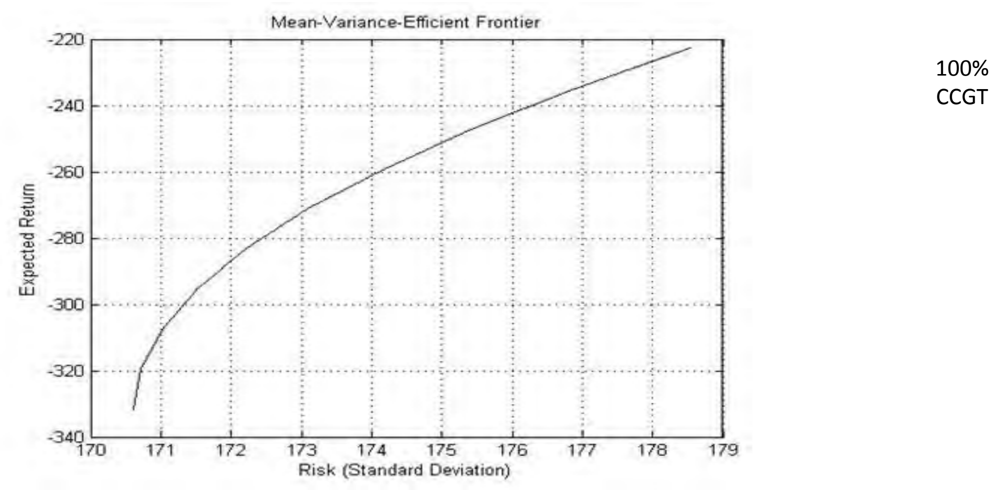


Figure 11: Efficient frontier for portfolios of CCGT and Nuclear, £m

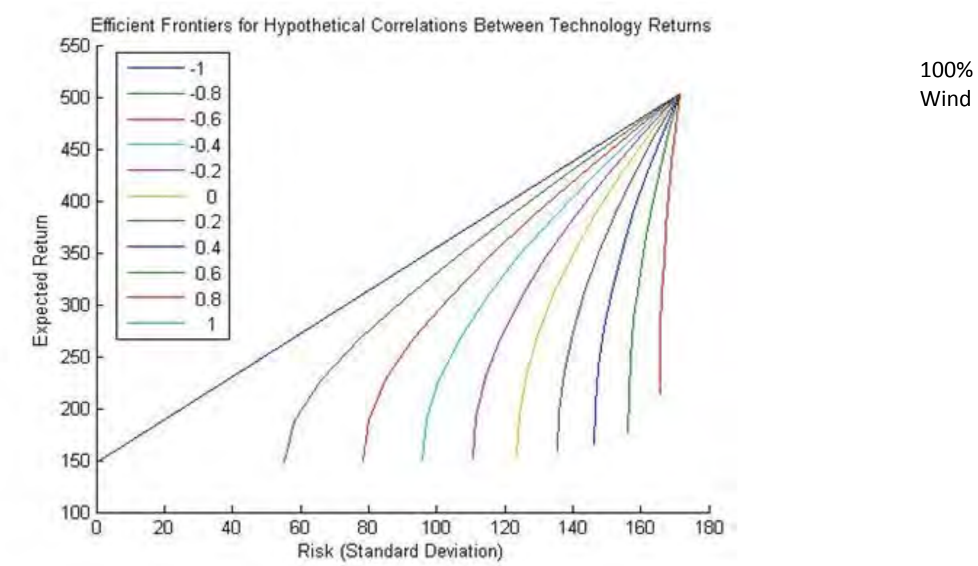


Figure 12: Efficient frontiers for portfolios of CCGT and wind – different hypothetical correlations, £m

This combination provides an interesting result. Firstly, for strong correlations, adding CCGT to a portfolio of wind assets does not have a substantial risk reducing portfolio effect. In fact, for a correlation greater than 0.8 an efficient frontier does not exist. This makes sense given that CCGT returns are lower than those of wind assets despite being more risky. As returns move towards a perfectly negatively correlated state, the risk reduction becomes larger relative to the reduction in returns. *Figure 13* shows the efficient frontier for these assets given the observed return correlation of 0.006.

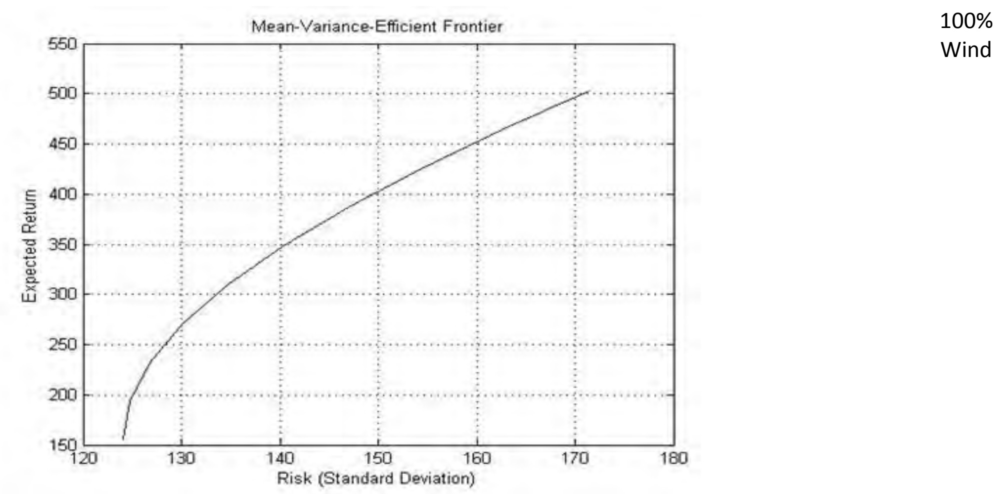


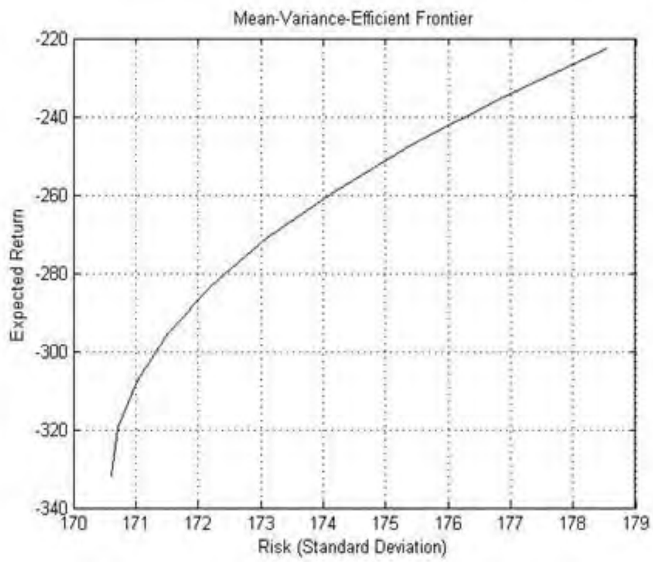
Figure 13: Efficient frontier for portfolios of CCGT and Wind, £m

Due to the lower variance of CCGT returns, an investor who has a lower risk tolerance than that required to invest in a pure wind portfolio can complement wind assets with gas generation. The GMV portfolio yields a NPV of around £150m, significantly higher than for any other two-asset combination. Hence, if an investor were restricted to investing in only two types of generation assets she would make the most efficient use of her capital by investing in this combination. The following section examines three-asset portfolios in order to assess whether further diversification offers any advantages.

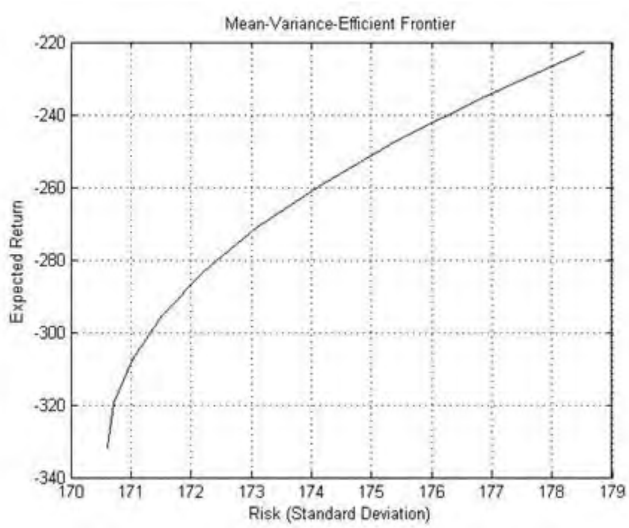
4.5 Optimal Portfolio: Three assets

Figure 14 displays an efficient frontier for combinations of CCGT, coal and nuclear plants given the observed correlation coefficients detailed in *Table 6*. For comparative purposes it is compared to a CCGT-nuclear portfolio since this offers a more attractive investment opportunity than a combination of CCGT-coal portfolio as noted in section 4.4.

As the high correlation between coal and gas returns means the inclusion of both technologies in a portfolio is inefficient, it is not surprising that graphs A and B are the same. There is no three-asset portfolio of gas, coal and nuclear assets that offers a more efficient outcome than portfolios of CCGT and nuclear alone. This is consistent with observations of the power industry today as the high carbon intensity of coal plants is attracting criticism from environmentalists and politicians alike, and means that coal plants are more sensitive to carbon prices than other technologies. For instance, the assumptions applied in this study are based on data provided by the DECC (2013a), which suggest that coal plants emit 886 tonnes of CO2 per GWh of electricity compared to the 355 tonnes per GWh emitted by gas plants. Hence, the cost of allowances to cover carbon emissions is higher for coal generation.



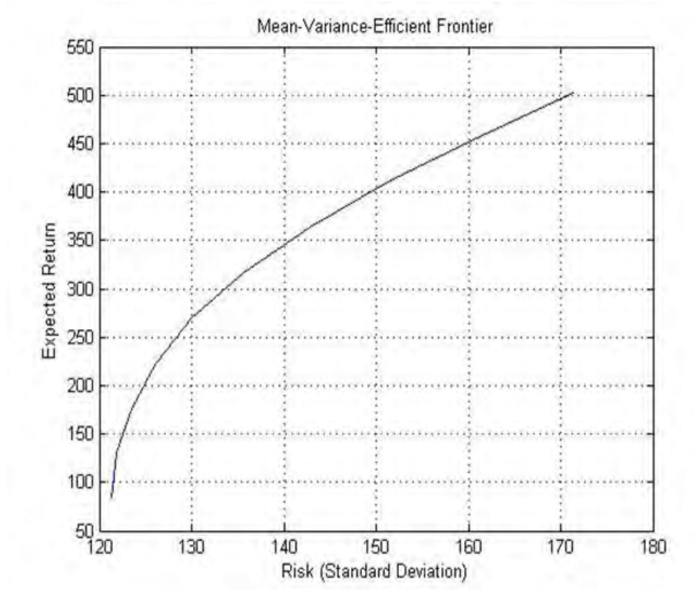
a) CCGT, Coal and Nuclear



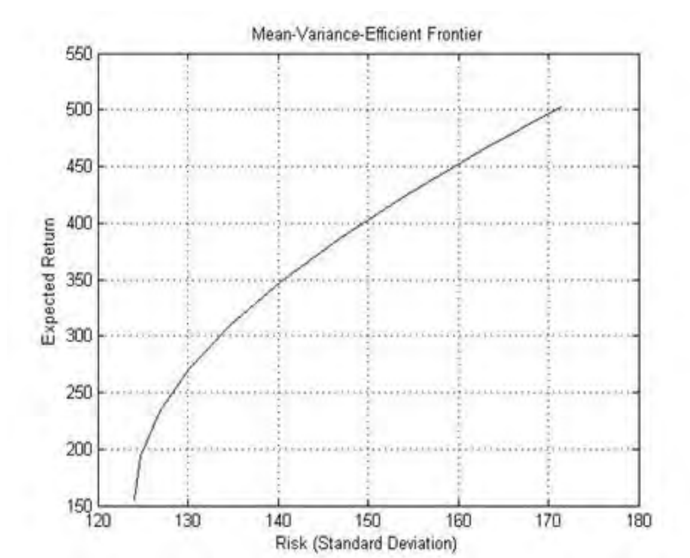
b) CCGT and nuclear

Figure 14: Efficient frontier for portfolios of CCGT, Coal and Nuclear – comparison to portfolios of CCGT and Nuclear, £m

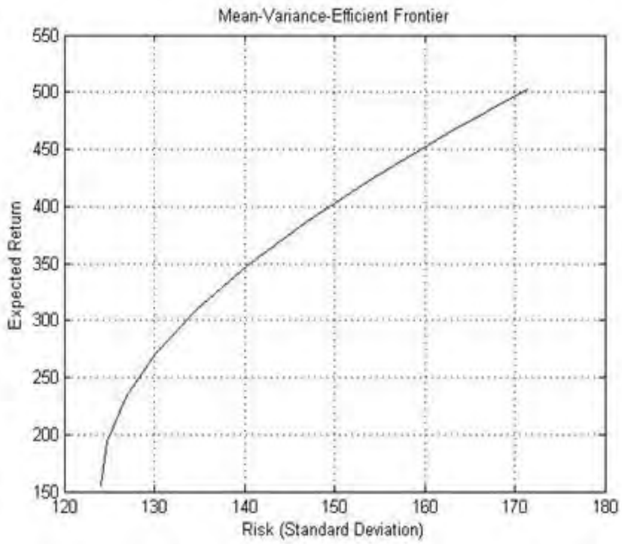
Figure 15 shows the efficient frontier of CCGT, nuclear and wind assets. For comparative purposes, the efficient frontiers of both CCGT-coal-nuclear portfolios and CCGT-wind portfolios have been provided.



a) CCGT, Wind and Nuclear



b) CCGT, Coal, Nuclear



c) CCGT and Wind

Figure 15: Efficient frontier for portfolios of CCGT, Nuclear and Wind, £m

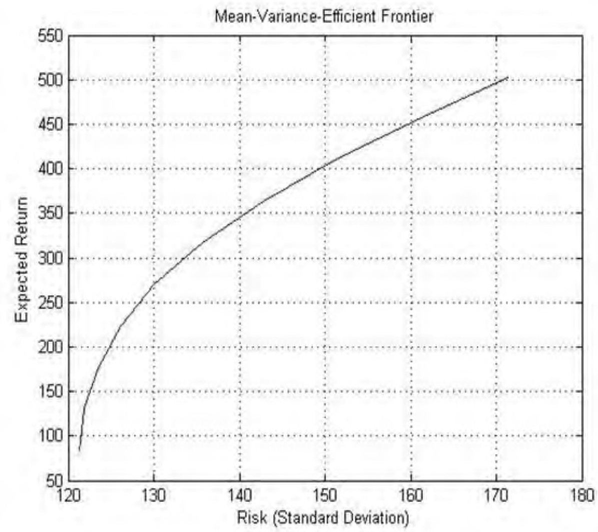
Replacing coal with wind assets has a dramatic effect. It is possible to construct a CCGT-wind-nuclear portfolio whose GMV portfolio is characterised by a NPV standard deviation of c. £122m, compared to over £170m for the CCGT-coal-nuclear combination. Furthermore, this portfolio yields an expected NPV of £80m versus -£330m.

Whilst it seems unlikely that a portfolio of all four generation technologies will produce any further benefits to the CCGT-wind-nuclear, or the CCGT-wind portfolio, the following section examines the efficient frontier of such portfolios.

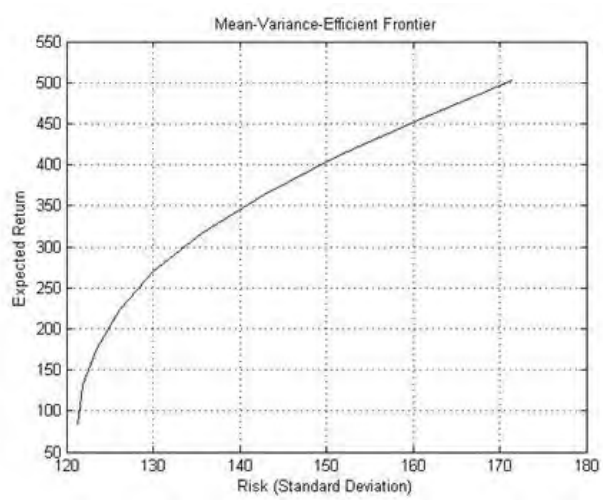
4.6 Optimal portfolio: four assets

Figure 16 displays this four-asset efficient frontier, comparing it to the two most attractive asset combinations previously identified.

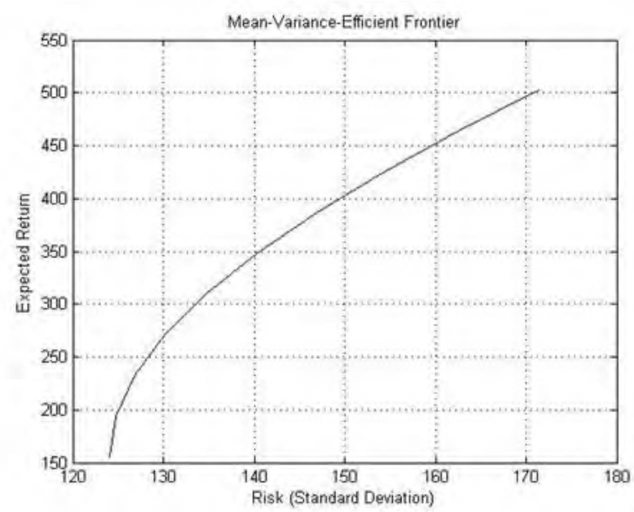
Graphs A and B are the similar, signaling that coal neither reduces risk nor enhances returns relative to a three-asset portfolio. Whilst coal plants have higher expected returns and a lower variance of expected return than nuclear plants, we have seen how the strong correlation between coal and gas returns means combining the two assets in the same portfolio makes little sense. Therefore it is not surprising that coal does not form part of an optimal portfolio.



a) CCGT, Coal, Nuclear and Wind



b) CCGT, Wind, Nuclear



c) CCGT and Wind

Figure 16: Efficient frontier for portfolios of CCGT, Coal, Nuclear and Wind, £m

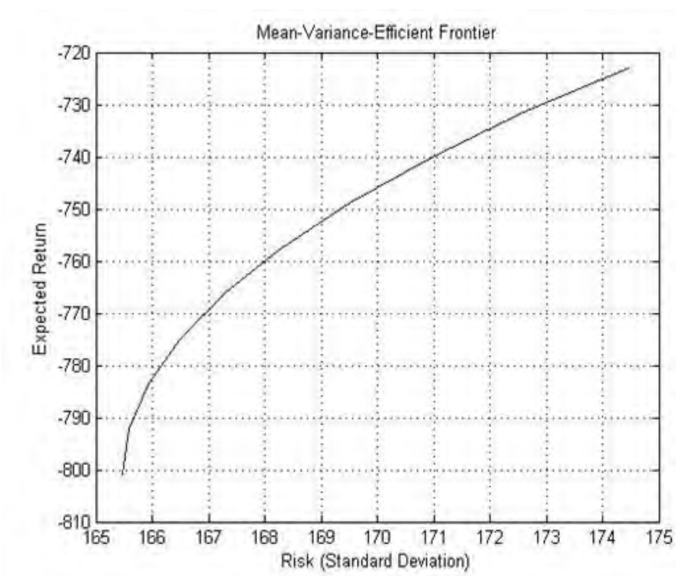
4.7 Optimal portfolios with Power Purchase Agreements

This analysis has so far focused on liberalised electricity markets with uncertain electricity, fuel and CO_2 prices. A power producer, however, could benefit from secure future revenues. For example, since investing in power infrastructure is by nature long-term, capital spending decisions are extremely important and it is helpful to be able to predict profits in advance. For this reason, power producers sometimes seek to lock in guaranteed prices for their power by signing long-term power purchase agreements (PPAs). These agreements consist of contracts between two parties that specify a particular quantity of electricity to be supplied at a specified price over a certain time period. Whilst many PPAs were between state utilities and private power producers, in liberalised electricity markets they often occur between two private parties.

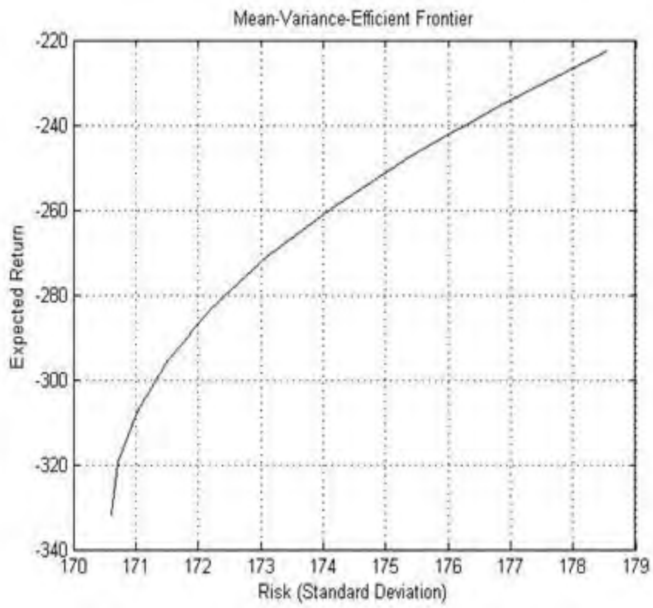
This section examines the impact of agreeing a constant electricity price on the optimal portfolio, taking first a three-asset portfolio excluding wind. To simplify the analysis we assume that a PPA is agreed upon the start of operation and covers the entire life of the plant. We also assume that the agreed upon rate is in line with electricity prices at the start of 2009. *Figure 17* shows the efficient frontier of CCGT-coal-nuclear portfolios under this scenario, with the CCGT-nuclear and CCGT-coal-nuclear frontiers from *Figure 14* displayed for comparison.

Recalling our observations from Figure 14, the frontier of a CCGT-nuclear asset combination is the same as that of a CCGT-coal-nuclear combination. Furthermore, we can see that the introduction of a power purchase agreement reduces the returns of a three-asset portfolio, with the GMV portfolio achieving an expected NPV of c. -£800m. The reason for this is that our analysis assumes the plant begins operation in 2009. Figure 4 shows that the electricity price was significantly depressed at the time of signing the contract, highlighting a potential danger in the negotiation of a PPA: unpredictable electricity prices mean that producers run the risk of missing out on any future upside to the power price. The standard deviation of this PPA-based portfolio is admittedly smaller, however an investor can achieve a marginally higher standard deviation of £170-£171m with a significantly higher expected NPV of around -£330m by investing in a CCGT-nuclear portfolio that is not characterised by power purchase agreements.

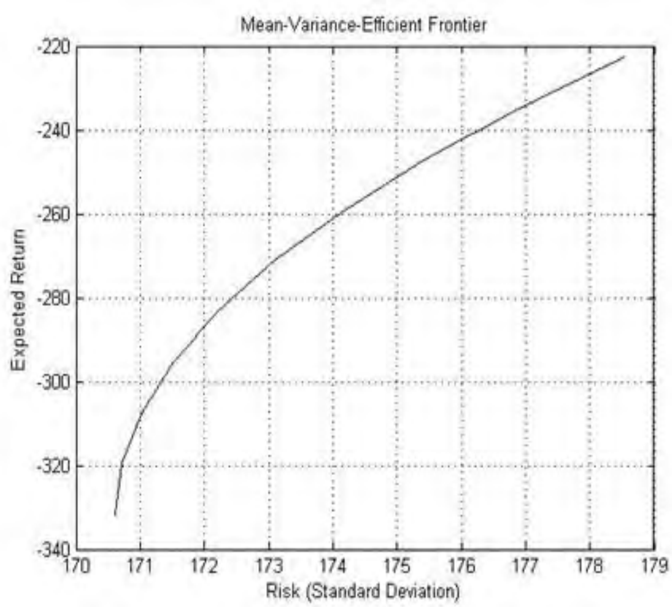
Introducing wind assets under the assumption of PPAs has an interesting conclusion. Table 7 displays the expected NPV and its standard deviation for each technology. Since wind plants do not have either a CO2 or a fuel cost, a PPA eliminates the only uncertain variable, meaning the risk of investing in a wind plant falls to zero. Of course this is a simplification since we assumed that all other variables in the discounted cash flow model are certain. In order to provide further clarity on the impact of PPAs for wind assets it would be necessary to make alterations to variables such as the load factor, operating and maintenance costs and ancillary revenues. In this simplified scenario, it is possible to reduce the standard deviation of the expected NPV to zero by holding only wind assets that have secured long-term PPAs. The expected NPV of this portfolio would be £276mn. Since the equivalent figures for each of the remaining three technologies are lower, and since the standard deviations are greater than zero, there is no point creating a multi-asset portfolio and an investor should allocate all of her capital to the wind asset.



a) CCGT, Coal and Nuclear – PPA



b) CCGT, Coal and Nuclear – No PPA



c) CCGT and Nuclear – No PPA

Figure 17: Efficient frontier for portfolios of CCGT, Coal and Nuclear – long-term PPA contract, £m

Technology	Mean	Std. Deviation
CCGT	-722.89	174.45
Coal	-1721.51	180.92
Nuclear	-1539.38	549.04
Wind	275.86	0

Table 7: Mean and standard deviation of expected NPV with PPAs

Source: Authors' own calculations

The simplification we have made is important, and if other variables were treated as uncertain then the revenues of a wind plant would not be risk-free. The analysis does, however, highlight the significant advantage of investing in power generation that is not affected by fuel prices. Whilst it would be interesting to include uncertain load factors for wind generation, we show that even with an assumed load factor of 27%, compared to 57% for coal, 71% for nuclear and 30% for gas generation, the returns on wind assets are relatively high.

It would also be useful to extend the analysis to cover the introduction of gas and coal procurement contracts for hedging fuel input risks, and the impact of contracts with different levels of flexibility. Flexibility is determined by the precise technology installed in a power plant as well as the terms and conditions of the contract and exposure to fuel prices depends on (1) the correlation between generation costs and fossil fuel prices, (2) the variance in fuel prices, (3) the risk allocation between investors in the power plant and other parties through long-term contracts, and (4) the investor's ability to mitigate the risk to which she is exposed (Roques, 2007).

In a separate study, Charalampous and Madlener (2016) use a multivariate GARCH model to identify the optimum forward contract for hedging power output and fuel input price risk simultaneously, concluding that spot electricity and coal prices should be hedged with long-term contracts, while natural gas prices are more effectively hedged with short-term futures. In light of this, it would seem plausible that procurement contracts of different lengths may be required for coal and gas generation.

It should also be noted that the determinants of the average load factor in a given year for a particular type of electricity generation are complex. The merit order, a ranking of energy sources in order of their short run marginal cost, changes over time. As the sole component of marginal cost for a renewable plant is the operating cost, price per unit of electricity generated is lower than that of conventional plants. As a result, transmission companies buy from renewable plants before turning to fossil fuel plants. Importantly, therefore, conventional plants are also susceptible to variations in the load factor, which depends on the load factor of the technologies that precede them in the merit order.

5. Conclusions and Policy Implications

This paper studies the extent to which fuel mix diversification can mitigate the risks associated with uncertain electricity, fuel and CO_2 prices and identify the incentives to invest in generation technology mixes. This has two important implications: firstly, it allows us to revisit current allocations of capital from private investors and ascertain whether they make choices consistent with Mean-Variance Portfolio theory. In other words, it allows us to identify whether investors are making efficient long-term diversification choices. Secondly, in the context of energy security, the government has an interest in directing investment towards technologies that ensure a secure future. By analysing the risks associated with different combinations of assets we can assess whether this objective aligns with the private objectives of investors. Furthermore, if incentives are not aligned, it may be possible to improve government policy.

The results show that when the correlation between electricity, fuel and CO_2 prices is taken into account, private investors would achieve the most efficient outcome by investing in a combination of CCGT, wind and nuclear generation assets. *Table 8* summarises the composition of power generation portfolios for each of the 'Big 6' utility companies in the UK.

Most of these companies source a significant proportion of energy from coal and an insignificant proportion from renewable technologies. We have even seen large utilities disposing of renewable energy portfolios since the financial crisis. When demand for power dropped, many of these firms were left over-invested and large proportions of installed capacity remained out of use. The consequence was that they streamlined their businesses by offloading 'non-core' assets, which included renewable technologies. Also, only EDF and Centrica have made the decision to invest in nuclear assets.

UK Utilities	**Parent Company**	**Installed Capacity (MW)**				
		Gas	**Coal**	**Nuclear**	**Renewable**	**Total**
British Gas	Centrica	3,400	-	1,800	540	**5,740**
EDF Energy	EDF	1,332	4,000	8,900	599	**14,831**
E.ON UK	E.ON	3,747	2,000	-	518	**6,265**
npower	RWE	1,998	600	-	-	**2,598**
Scottish Power	Iberdrola	1,967	2,304	-	2,189	**6,460**
SSE	SSE Group	5,055	2,000	-	3,326	**10,381**

Table 8: Installed capacity breakdown of 'Big 6' utility companies

Source: Company information, 2014

The Power of Wind

We showed that wind investment improves the characteristics of power portfolios for private investors. In addition, renewables form an important component of a secure energy mix; as we have seen, fossil fuel prices are subject to uncertainty. Domestically, the annual growth rate of primary energy production has been negative in every year since 1999[7]. In order to avoid over-reliance on fuel imports, it makes sense to utilise sustainable technologies and it is in the interest of both the private and public sectors to encourage investment in wind power. In this respect there are several informative findings of this study.

The Feed in Tariff system sets a 'strike price' for each type of technology, guaranteeing that generators will receive a certain price for the electricity they supply. If the market price is below this level, the government covers the deficit. On the other hand, if the market price is above the strike price, the generator pays the surplus to the government. Therefore, the volatility in revenue is limited to being a function of the volatility in electricity output, itself a function of load factor and plant efficiency, and electricity price risk is eliminated. Investors can predict with greater certainty the revenues from investing in wind technology, increasing the incentive to invest.

Secondly, a factor discouraging investors from investing in wind is that the levelised cost of energy (LCOE) is higher than for conventional fuels. The LCOE calculation, however, ignores the impact of future carbon costs. When these factors are considered, many estimate the cost of wind energy to be highly competitive with that of fossil fuel energy. A carbon price floor can also provide additional incentives to invest in low-carbon technology by increasing certainty over the future price of carbon.

The Old Guard: Implications for Conventional Fuels

This analysis indicates that coal should not be present in an optimal portfolio. Whilst gas prices in 2012 reached levels that shifted the balance of electricity generation from gas to coal (DECC, 2013a), the returns from gas generation outweigh those from coal over a five-year period. From an energy security perspective, one might argue that due to the added diversification of including coal, we should continue generating a proportion of energy from coal. Additionally, natural gas production has fallen by 64% since peaking in 2000. However, domestic coal production is also declining and coal imports were 38% higher in 2012 than 2011 meaning coal production remains susceptible to import risk in a similar way to gas.

To some extent, the findings suggest that IGCC coal plants can be phased out. The Emissions Performance Standard (EPS) limits the emissions of fossil fuel plants to 450g/kWh, which means that all new coal plants will require carbon capture and storage (CCS) technology, thereby eliminating IGCC plants without CCS technology installed. Furthermore, strike prices under the Contracts-for-Difference system apply to co-fired biomass generation. A proportion of the fuel used in fossil fuel plants can be substituted with biomass such as wood, olive cake and energy crops, providing the incentive to replace coal with a renewable

[7] Data provided by the DECC (2013a).

source. Whilst biomass generation is outside the scope of this research, removing the least efficient fuel from portfolios seems a step in the right direction.

Although there are concerns over the flexibility of nuclear power, it is central to the long-term plan of replacing aging capacity whilst meeting carbon objectives. Energy security concerns suggest that nuclear will be important due to the risks from imported gas and coal. We showed that regardless of the social benefits, nuclear power is a desirable component of a generation portfolio. Whilst a Contract-for-Difference charge was announced in 2014 in connection to the Hinkley Point nuclear plant, subsidies for the nuclear industry are generally ill defined.

Finally, the methodology presented in this paper has some potential drawbacks. The assumptions to simplify the analysis also prevent the results from being comprehensive. The simulations were run on the basis that generators cannot mothball plants and halt production when it becomes uneconomical. In reality the ease with which this can be done differs across technologies; CCGT plants have the shortest start-up time and coal and nuclear the longest. Furthermore, some types of gas, coal and nuclear plants are ignored in this paper. The characteristics of a CCGT plant without carbon capture and storage (CCS) technology are different from those with CCS capabilities, and the properties of an integrated gasification combined cycle (IGCC) plant - the specification used here as a proxy for all coal plants - differ from those of a pulverised coal plant or an IGCC plant with CCS technology.

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ABBREVIATIONS

AGC: Advanced Gas-Cooled

CCGT: Combined-cycle gas turbine

CCS: Carbon capture and storage

CEGB: Central Electricity Generating Board

CfD: Contract-for-Difference

DCF: Discounted cash flow

DECC: Department of Energy and Climate Change

DOE: Department of Energy

DTI: Department of Trade and Industry

EAC: Environmental Audit Committee

EIA: Energy Information Administration

EPS: Emissions performance standards

EUA: European Union allowance

FiT: Feed-in Tariff

GMV: Global minimum variance

IEA: International Energy Agency

IGCC: Integrated gasification combined cycle

LCOE: Levelised cost of energy

MVF: Minimum variance frontier

MVP: Mean-Variance Portfolio

NPV: Net present value

OTC: Over-the-counter

PPA: Power purchase agreement

R&D: Research and development

WACC: Working average cost of capital

WNA: World Nuclear Association