Carbon tax or carbon permits: the impact on generators' risks

Richard Green[*]

Institute for Energy Research and Policy
University of Birmingham
Birmingham B15 2TT
Tel: +44 121 415 8216
Email: r.j.green@bham.ac.uk

September 2006

This work is provisional: please check before citing it!

Abstract

Volatile fuel prices affect both the cost and price of electricity in a liberalised market. Generators with the price-setting technology will face less risk to their profit margins than those with a technology that is not price-setting, even if its costs are not volatile. Emissions permit prices may respond to relative fuel prices, further increasing volatility. This paper simulates the impact of this on generators' profits, comparing an emissions trading scheme and a carbon tax against predictions for the UK in 2020. The carbon tax reduces the volatility faced by nuclear generators, but raises that faced by fossil fuel stations.

JEL: L94
Keywords: Electricity, emissions trading, emissions taxes, fuel price risk

[*] This research is supported by the Engineering and Physical Sciences Research Council through its Supergen FutureNET consortium, grant GR/S28082/01. I hope that my intellectual debt to the researchers of the Cambridge Electricity Policy Group for many of the concepts used in this paper is clear, and I would like to thank them for hospitality at conferences, and on sabbatical.

1. INTRODUCTION

Emissions trading schemes and carbon taxes work by raising the cost of producing electricity from fossil fuels. The more polluting the technology, the more its variable cost increases. This should provide an incentive to shift generation towards low-carbon technologies. We know that taxes and permit schemes should have equivalent results in a world of certainty, but that they perform differently in an uncertain world. This paper considers their different impact on the profit risk faced by electricity generators with a choice of technologies.

The standard analysis of investment choices in electricity uses a cost-minimising approach. Investors do not choose to build new power stations solely on the basis of their expected costs, however. Companies wish to make profits, and to avoid excessive risks. Roques *et al.* (2006b) show that a probabilistic analysis is needed to give the full picture of the expected return on an investment, and its distribution. One particular issue discussed by Roques *et al.* (2006c) is that if the cost of gas is correlated with the price of electricity, the profit margin of a gas-fired generator can be less risky than either its costs or its revenues, considered in isolation. The profit margin of a nuclear generator may be much more risky than that of the gas-fired station, since its costs will not be as correlated with the price of electricity.

This paper asks how the choice between a carbon tax and an emissions permit scheme (based on auctions) affects the risk of investing in gas-fired or in nuclear generation. With a carbon tax, the variable cost of gas-fired generation is raised by a fixed amount, which will normally feed through into electricity prices. With carbon permits, the price of emissions depends upon market conditions. In the specific case of the electricity industry, the key factor is the relationship between coal and gas prices. Taking a slightly Euro- and electricity-centric view, the price of carbon will be set so that the electricity industry within the EU reduces its emissions to the level that is needed in order that the demand for emissions permits equals the supply. Assuming that fuel prices are such that coal-fired generation would be cheaper than gas-fired, in the absence of the ETS, this implies that the price of carbon has to rise until enough coal-fired stations have been displaced by gas generation. The price of carbon is then at the level which equalises the cost of some gas-fired and coal-fired stations (Newbery, 2006). A rise in the price of gas will tend to raise the price of permits. The higher gas price thus has both a direct effect on the price of electricity, and an indirect effect via the cost of emissions.

The aim of this paper is to discover whether this magnified relationship between gas and power prices has a significant impact on the relative risk of different kinds of generator, compared to the alternative of a carbon tax that was not linked to the level of fuel prices. The paper follows the same basic approach as the papers already cited, but uses a more detailed model of the relationship between input prices and the wholesale price of electricity, that of Evans and Green (2005). This allows us to calculate the expected profitability of each type of power station, taking into account the way that its operating pattern will depend upon its variable cost relative to other stations.

The next section briefly discusses the background to the Emissions Trading Scheme and the economics of a liberalised electricity industry. Section 3 outlines the supply function model used to determine the relationships between fuel and carbon prices and generator profits. Section 4 presents the data used, drawn from the DTI Energy Review (2006) and Supergen FutureNET scenarios (Elders *et al*., 2006). Section 5 presents the results and section 6 concludes.

2. THE ELECTRICITY INDUSTRY AND THE EMISSIONS TRADING SCHEME

Traditionally, the electricity industry has largely been vertically integrated. Large companies that combined generation and transmission might sell power to smaller distribution utilities, but this was usually done via contracts or tariffs, rather than with any kind of market mechanism. Following Chile, England and Wales, and Norway, many countries have now adopted wholesale markets for electricity, with competition between generators. While the details vary across countries, the key elements are that generation has been split from transmission, that entry into generation is largely deregulated, and that generators compete to sell their output, through a centralised market, bilateral contracts, or both.

This has changed the way in which companies need to think about investment. Traditionally, investment plans were made with the objective of minimising the expected cost of meeting the forecast level of demand. There could be a trade-off between capital costs and fuel costs – plant that was expected to run for most of the time could incur high capital costs in return for lower fuel costs (the standard example being nuclear power) while still being competitive against plant with lower capital costs but high fuel costs. For plant that was not expected to run for much of the time, it would not be worth incurring the high capital costs. Most newly-built plant *was* expected to run nearly continuously on base load, however, and so valid cost comparisons could be made on the basis of the expected cost per kWh generated at a standardised, high, load factor. The option with the lowest expected levelised cost would normally be the front-runner for investment. The classical investment appraisal appeared to take little notice of risk or uncertainty.

In a market-based system, companies invest to earn profits. Their first criterion will not be to minimise the expected cost of meeting demand, but to maximise the expected difference between their costs and their revenues. In a fully competitive market, in which the company was not able to influence the prices a plant received, this would come down to minimising its expected cost, as with the pre-liberalisation approach. This equivalence between the outcome of a perfect competitive market and a perfect social planner is, after all, one of the arguments for liberalisation.

Companies in the market-based system have a second criterion beside the level of profits, however. Typically, they wish to avoid taking on excessive risk. One approach for this is to sign long-term contracts for fuel inputs and electricity sales at the start of construction, locking in the plant’s selling margin. This depends on finding counter-parties willing to take on the risk of these contracts. In Finland, a group of energy-intensive industrial customers has contracted to take the output from a new-build nuclear plant, which should give them stable power costs throughout their own long-lived investment cycle. A company selling to captive customers would also be a natural counter-party for the electricity contract, but liberalisation may have deterred electricity retailers who might lose their customers from taking on such commitments (Newbery, 2002). In the absence of a contract to lock in the risk, companies will have to trade off risk and expected profit when deciding on investments.

In a liberalised market, the wholesale price of power should be related to its marginal cost. The more competitive the market, the closer prices should be to marginal cost. At times of peak demand, this marginal cost should be understood to include the cost of rationing demand if this is necessary to match it with the available capacity. At other times, marginal cost consists of fuel and variable operations and maintenance costs, with fuel costs dominating.

The marginal cost of the system naturally depends upon which plants are operating, since the most expensive of these will determine the system’s marginal cost. The approach used in the traditional system was essentially to stack the plants in a merit order of increasing marginal cost, and to call on the lowest-cost plants first.[1] Nuclear plants were expected to run on base load, while high (marginal-) cost open cycle gas turbines would only operate at times of high demand. These stations suffered from both a low thermal efficiency and a fuel that was usually expensive. Other stations might trade off a higher fuel price against a greater thermal efficiency – this was the situation with Combined Cycle Gas Turbines in the UK for much of the 1990s, which paid more per kWh of fuel than coal-fired plants did, but needed less fuel per kWh generated, giving them a lower marginal cost. When fuel costs change, however, the merit order will change.

In the European Union, a new component has recently been added to generators' marginal costs, with the introduction of the Emissions Trading Scheme. Adopted in response to the Kyoto Treaty on greenhouse gas emissions, the ETS requires all large combustion plants in the EU to surrender an emissions permit for each tonne of carbon dioxide that they emit, or pay a penalty. These permits are issued by Member States, following national allocation plans that have to be approved by the European Commission. The intention is that the plans will be consistent with each country's commitments under the Kyoto Treaty and the EU's burden-sharing agreement, which provides for differential reductions relative to each country's 1990 baseline, depending on its individual circumstances. If "business as usual" would involve more emissions than are compatible with these commitments, then there will not be enough permits to go round. Their price will rise, and this should signal a need for companies to change their behaviour.

The first phase of the scheme runs from 2005 to 2007, with a second phase from 2008 to 2012, covering the Kyoto commitment period. So far, permit prices do appear to be passed through into electricity prices. In 2005, prices in Germany and the Netherlands rose by between 60% and 117% of carbon costs (Sijm *et al*, 2006). This is in line with the predictions of economists, but not perhaps of politicians who expected that if most permits were granted free of charge, keeping companies' average costs unchanged, then they would not change their prices (Gabriel, 2006).

The free allocation can have important effects on companies' investment behaviour, however (Green, 2005). If permits are given away to plants that continue to operate or are newly built, but not to those that close, this can be seen as a subsidy towards their fixed costs, coupled with a tax on their marginal costs. The tax is passed through to prices, while the subsidy gives an incentive to keep more capacity open. To the extent that peak prices depend on the margin of capacity, this effect can offset some of the scheme's impact on marginal costs, limiting the overall effect on average prices in the long run. The way in which permits are given away can also affect the choice of technology. If the allocation is linked to past emissions, or to the technology chosen by a new plant, then more polluting plants will tend to get a more valuable allocation of permits. They will also need more permits, of course, but the greater allocations reduce the incentive to switch investment decisions towards cleaner technologies, and closure decisions towards more polluting ones. A technology-neutral allocation (which should even include giving away permits to nuclear stations) would maximise the scheme's impact on the choice of technology.

If giving away carbon emissions permits to nuclear plants seems politically unattractive, an alternative would be to auction the permits. Since the combination of free

[1] In practice, a more complicated optimisation is required to take account of constraints such as limits to the rate at which plants can change their output, and the cost of starting up a plant to meet a peak in demand, which tends to raise the true marginal cost at the peak well above the "steady state" variable cost of meeting that level of demand if it were to persist for a long time. Similarly, it is expensive to restart a plant after switching it off when demand is low, and the benefit of avoiding this reduces the marginal cost at times of low demand. These complications are not important for the purposes of this paper.

allocation and permit prices feeding through to power prices gives electricity generators a windfall profit, auctioning the permits would claw this profit back to governments. The UK government has announced that it will auction 7% of its permits in phase II of the ETS – the rules for the scheme set an upper limit of 10% for this phase. It remains to be seen whether this limit will be relaxed in future phases (and indeed, whether there will be any future phases).

In a world of certainty, auctioning permits starts to look very like an alternative method of dealing with externalities, a Pigovian tax. If the price of the permit could be predicted, the same amount could be imposed as a tax, with very similar economic effects. It is quite possible, however, that the costs of administering the tax would be lower than those of trading permits. In an uncertain world, the two schemes will have different effects, as one fixes the quantity of emissions, while the other fixes the amount that companies are prepared to spend to avoid it. Weitzman (1974) shows that if the marginal damage from pollution and the marginal cost of avoiding it are uncertain, the optimal economic choice between the two systems depends on the relative slopes of the functions relating marginal damage and cost to the level of pollution. In the case of global warming, the marginal damage is believed to be quite insensitive to the level of emissions in any one year, implying that a tax would be a more suitable economic instrument. The politics of rent-seeking favour a permit system, however, as interest groups can argue for the free allocation of valuable permits, as has happened with the ETS.

What determines the value of permits? The answer is supply and demand, or rather perceived supply and demand. When the scheme started, data on carbon emissions in the EU was very incomplete, and the release of the first comprehensive data in May 2006 caused a significant fall in permit prices. Market participants realised that emissions had been lower, relative to the supply of permits, than they had believed, implying that the price needed to align the two was also lower. It is unlikely that there will be significant investment effects during phase I of the ETS, given the short timescales involved, and balancing emissions with the supply of permits depends upon operating decisions. If the price of electricity rises, demand for it should fall, reducing emissions, but the key operating decision will be between gas- and coal-fired power stations. Gas contains carbon and hydrogen, while almost all the energy content of coal comes from carbon, implying that burning coal will produce more CO2 per unit of energy than burning gas. Furthermore, many gas-fired stations in Europe are combined cycle gas turbines with higher thermal efficiencies (lower heat rates) than coal-fired plants. This implies that switching from coal-fired to gas-fired stations will typically reduce emissions. If the price of gas is low, gas-fired plant will naturally be above coal plants in the merit order, and emissions will be low. If the price of gas is high, however, coal will be favoured. If this is incompatible with the number of permits available, then the price of permits should rise in order to reduce coal's cost advantage and give generators an incentive to burn more gas. We would then expect the price of permits to be positively correlated with the price of gas, and negatively correlated with that of coal.

These correlations, and the correlations between fuel and electricity prices, are at the heart of what follows. If generators are worried about profit risks, then they will have an incentive to choose technologies with costs that are correlated to power prices. The costs of gas-fired stations have this property, while those of nuclear stations do not. If carbon prices are also correlated with gas prices, then this will increase the volatility of both power prices and gas-fired generators' costs, while they remain correlated. Nuclear stations are not exposed to carbon prices and will be relatively more risky. The next sections of the paper set out the model that is used to test this theory.

3. A SUPPLY FUNCTION MODEL

This paper uses a supply function model to predict generators' profits, given input costs and the level of demand. Klemperer and Meyer (1989) introduced the supply function equilibrium, while Green and Newbery (1992) applied it to the British electricity market. As argued in that paper, the supply function equilibrium is a close approximation to the workings of the Pool, in which companies effectively had to submit offers of prices and quantities (from each of their many power stations) that would hold throughout the following day.[2] These offers can be represented by a supply function, and the equilibrium price and output in each period are given by the intersection of the aggregated supply function with the market demand curve. Demand varies over time, which is mathematically equivalent to the stochastic variation considered by Klemperer and Meyer.

Formally, demand is denoted by $D(p,t)$. Assume that $dD/dp < 0$, and that $d^2D/dp^2 \leq 0$. There are n generators, which compete by submitting supply functions $(q(p): R \rightarrow R,\ i = 1...n)$ which state the amount they would be willing to produce (q) at any price (p). These functions must be non-decreasing in p - the Pool's rules ensure this by ranking plants in order of increasing bids. The price at each time is determined by a market-clearing condition. The total output supplied at the market-clearing price must just equal the demand with that price at that time:[3]

$$D(p^*(t),t) = \sum_i q_i(p^*(t)) \tag{1}$$

An equilibrium consists of a set of supply functions, one for each firm, such that each firm is maximising its profits, given the supply functions of the other firms, at every time. We can write each firm's profits π_i (revenues, less the cost $(C(q))$ of production) at each time as a function of price, assuming that it produces the residual demand (that is, total demand less the other firms' supply at that price) in order to meet the market-clearing condition:

$$\pi_i(p,t) = p\left(D(p,t) - \sum_{j \neq i} q_j(p)\right) - C_i\left(D(p,t) - \sum_{j \neq i} q_j(p)\right) \tag{2}$$

This profit function can be differentiated with respect to price:

$$\frac{\partial \pi_i(t)}{\partial p} = D(p,t) - \sum_{j \neq i} q_j(p) + \left(p - C_i'\left(D(p,t) - \sum_{j \neq i} q_j(p)\right)\right)\left(\frac{\partial D(p,t)}{\partial p} - \sum_{j \neq i} \frac{\partial q_j}{\partial p}\right) \tag{3}$$

Setting this derivative to zero gives the profit-maximising price level at a particular time, and it also gives the profit-maximising output (i.e., the residual demand) at that price level. Assume that $\partial^2 D/\partial p \partial t = 0$, and then this price cannot be optimal for a different level of demand. The (price, quantity) pair will then form a point on the profit-maximising supply function. We can manipulate the first-order condition to give a differential equation for the firm's supply function:

[2] Companies could vary their available capacity each half-hour, but very rarely did so in a strategic manner (as opposed to not bothering to staff a peaking plant which would not run overnight, for example).

[3] For completeness, we assume that if there is no price which solves this condition, the price will be zero.

$$q_i(p) = \left(p - C_i'\left(q_i(p)\right)\right)\left(-\frac{\partial D}{\partial p} + \sum_{j \neq i} \frac{\partial q_j}{\partial p}\right) \quad (4)$$

A supply function equilibrium consists of a set of solutions to equation (4), one for each firm, such that the resulting functions are sloping upwards for every price that might be obtained from the intersection of a demand curve and the aggregate supply function. If the firms are symmetric, there is a wide range of potential supply functions, although it narrows as the variation in demand increases.

Evans and Green (2005) were able to simulate electricity prices from April 1997 to March 2005, using a symmetric approximation of the industry supply function. They modelled the industry as if it contained $\hat{n}$ symmetric strategic generators, together with a competitive fringe. In each month, $\hat{n}$ was the inverse of the Herfindahl index, calculated using the capacity of the strategic generators. This gives a straightforward differential equation:

$$q_i(p) = \left(p - C_i'\left(q_i(p)\right)\right)\left(-\frac{\partial D}{\partial p} + (\hat{n}-1)\frac{\partial q_i}{\partial p}\right) \quad (5)$$

Since only the industry supply function is required to predict prices and (overall) operating patterns, it is not necessary for $\hat{n}$ to be an integer. Following Evans and Green, this paper uses the highest-priced supply function that includes all of the firms' capacity – it starts from the price that the firms would charge if they were selling their full capacity in a Cournot equilibrium. This industry supply function is then combined with the supply curve of nuclear stations bidding at their near-zero marginal cost to give an overall supply curve, shown in figure 1. The predicted equilibrium price for a given period is then given by the intersection of this supply curve with the demand curve for that period. We can also find the marginal cost at this point, and hence infer which stations are generating.[4] This implicitly assumes that the industry truly *is* symmetric, since a smaller generator will produce more, relative to its capacity, than a larger one, and so marginal costs would not be equalised across asymmetric generators. For the purposes of this paper, this simplification is unlikely to create important effects.

4. CALIBRATION

Much of the data for this paper comes from the UK government's recently-published Energy Review (DTI, 2006, Annex B). Demand in 2020 is expected to be around 400 TWh in the DTI's central case. The pattern of demand within the year is assumed to be the same as in 2003-5, scaled up by 28% to give the desired total.

The review includes information on the costs of a range of generating technologies, and predictions of fossil fuel prices, expressed as central, high and low cases. The variable cost of a power station is equal to the price of its fuel and carbon (permit or tax) per kWh of fuel, divided by its thermal efficiency, plus its variable operations and maintenance costs. The review also gives information on fixed operations and maintenance costs, capital costs

[4] With continuous marginal costs, there is a specific marginal point on the cost function, and all capacity with marginal costs below this level would be operating. This paper uses a step function, and so it will typically be the case that not all of the marginal tranche of capacity will be operating – we assume that each plant in the tranche has the same chance of running. When calculating the variability of profits, however, we treat a 50% chance of running as a deterministic period of operation at 50% of capacity.

(per kW) and the expected life of the plants. The capital costs were converted to annual figures with a discount rate of 10%. Where the DTI gives two figures, the mid-point is used.

The three main technologies considered in the industry supply function are new coal-fired stations, combined cycle gas turbines, and nuclear stations. A small amount of oil-fired plant, and prototype stations with carbon capture and storage, was also included in the model. These higher-cost plants have the effect of raising the industry's marginal cost at the far end of its supply function, and hence raising the price received by all the other plants. The amounts of coal- gas- and nuclear plants were taken from one of the Supergen FutureNET scenarios for 2020 (Elders *et al.*, 2006), "supportive regulation". This scenario has a slightly greater demand for electricity than the DTI's base case, however, and so this paper assumes slightly less CCGT capacity than the scenario. We assume a Herfindahl index of 1/6, equivalent to six equal-sized firms, when deriving the supply function for the industry's non-nuclear capacity. Nuclear stations are assumed to run on base load and not to affect the market price.

Renewable generation is subtracted from the gross demand to give the net demand that must be met by large stations. Renewable output is stochastic, with a mean load factor of 33%, and a standard deviation (for nationwide output) of 5%. The net demand is then scaled up by a (deterministic) availability factor, to account for stations that are not able to generate. A factor of 80% is applied to the lowest demand levels (when more maintenance was performed), one of 90% to the highest levels (when only essential work kept plant out of service), and 85% to the rest. Without some adjustment for availability, low-cost plant would appear to generate too much, and prices would be too low. Previous work has involved different supply functions for different periods of the year, each adjusted by a different availability factor. Adjusting the level of demand (and then scaling the raw predicted outputs by the same availability factor) allows us to use a single supply function for the whole year, with a saving in computational time. Equilibrium prices and outputs are found for 51 representative demand curves (based the lowest level of demand, the 2nd percentile, and so on) for each set of fuel prices.

The prices of gas, coal, and oil are stochastic, with means equal to the DTI's central predictions for 2020. All three have a normal distribution. The price of coal is a linear combination of the price of gas, a constant, and a second normal variable, while the price of oil is a linear combination of the price of gas, a constant, and a third normal variable. This produces a correlation between the price of gas and of coal (or oil) of around 0.45, while the correlation between the price of coal and the price of oil is around 0.2. These correlations are in line with the correlation between the annual average fuel prices paid by major power producers in the UK in the last ten years. The standard deviations are chosen so that the DTI's high and low cases are around two standard deviations away from the mean (although this cannot be exact, as the DTI cases are not symmetric). Table 1 shows the mean prices and their standard deviations:

Table 1: Fuel prices (£/MWh)

	Coal	Gas	Oil
Mean	3.98	12.45	16.00
Standard Deviation	1.34	3.00	4.50

In the model runs for the ETS, the price of carbon is equal to twice the difference between the price of gas and the price of coal, plus a normal variable with zero mean and a standard deviation of £1/tonne. The first part equalises the cost of a CCGT emitting 0.4 tonnes of CO2 per MWh and the cost of a coal-fired station emitting 0.9 tonnes per MWh, while the second recognises that the relationship will not be exact in practice. This gave an average carbon price of £16.97 per tonne of CO2, close to the DTI central figure of £17/tonne. The carbon tax imposed in the second set of model runs was £16.97 per tonne, ensuring that a change in the average level of tax was not responsible for changes in the performance of different technologies.

5. RESULTS

The model was simulated 15,000 times for carbon trading, and 15,000 times for a carbon tax. The key results are shown in table 2, and figures 2 and 3.

Table 2: The impact of carbon policy

	Profits (£ per kW-year)			Price (Annual average)
Carbon trading	CCGT	Coal	Nuclear	£/MWh
Mean	21.54	3.86	9.44	38.92
Standard deviation	5.86	14.20	47.32	6.37
Carbon tax				
Mean	23.79	5.35	10.99	39.12
Standard deviation	9.64	27.74	32.53	4.38

In this model, prices are slightly higher with a carbon tax than with a system of carbon trading, and this feeds through into the general level of profits. With carbon trading, there is a very strong correlation between the gas price and the carbon price, leading to a more volatile level of marginal costs. In this model, the reduction in prices when marginal costs are lowest is greater than the increase in prices when costs are high. The overall effect is to reduce the average level of prices, compared to those with a carbon tax. The difference in prices (some £0.2/MWh) leads to a difference in profits, for the nuclear stations, of £1.55/kW-year (since each kW produces just under 8 MWh a year). There is a similar increase for coal-fired plant, while the mean profits for a CCGT rise by somewhat more. When gas prices are low, a carbon tax gives CCGT stations a greater advantage than emissions trading, since low gas prices are partly offset by low permit prices. The converse is true for high gas prices, but in this model, the advantage at low gas prices dominates for the effect on profits.

Looking at individual stations, investing in CCGT plant is clearly the most attractive option, with higher predicted profits and a lower standard deviation, whether carbon is traded or taxed. Coal-fired plants appear least profitable under either system, while the returns to nuclear plant have the highest standard deviation. However, shifting from carbon trading to a carbon tax results in a noticeable reduction in the volatility of nuclear profits – their variance is halved. The variance of the profits of a coal-fired plant rises by a factor of nearly four, and the variance of a CCGT plant's profits nearly triples.

These shifts are not enough to reverse the ordering of gas and nuclear investment, but they could affect the choice between the second-best options of coal and nuclear. For example, firms might try to maximise a mean-variance utility function, given by:

$$U = \pi - \tfrac{1}{2} \lambda \, \mathrm{var}(\pi) \qquad (6)$$

If λ takes a value of more than 0.04, then investing in nuclear power is always worse than investing in a coal-fired station, because of its greater variance. If λ takes a value of less than 0.04, however, then the nuclear station is better than the coal-fired station. At these levels of

λ, however, the distinction is somewhat irrelevant, since neither project would have a positive utility. If λ falls to 0.03, investing in the coal-fired station would have positive utility in the case of carbon trading, while if λ takes a value of 0.02 or less, investing in a nuclear station would have positive utility in the case of a carbon tax. The gas-fired station will still be a much more attractive option, but the example does illustrate the importance of mean-variance trade-offs.[5]

Any company large enough to consider a nuclear investment will have a portfolio of plants, however. Awerbuch (2000) has applied portfolio theory from the finance literature to show that including renewable generators in a portfolio of plant can improve the trade-off between expected generating cost and its variability. Twomey (2005) and Roques *et al.* (2006a) show how this theory can be applied to different portfolios of thermal plant. Figure 4 applies this analysis to our results.

The two lines show the expected profits of different combinations of CCGT and nuclear stations, under emissions trading and a carbon tax. The greatest expected profits are obtained with a portfolio consisting only of CCGT stations, while a portfolio of nuclear plants will give the lowest expected profits, under either policy. The profits of the gas-only portfolio also have a much lower standard deviation than those of the 100% nuclear portfolio. These points, at the extreme ends of the lines, are just another way of presenting the results from table 2.

The profits of CCGT stations are negatively correlated with those of nuclear stations. The correlation coefficient is -0.53 with carbon trading, and -0.59 with a carbon tax. This means that adding some nuclear stations to a portfolio of CCGT plants will reduce the overall risk of the portfolio, even though the nuclear stations are individually more risky than the CCGT plants. The lines therefore initially slope down to the left as we move away from the gas-only portfolio. As more nuclear plants are added, their greater variability becomes more important than their diversification effect. Quite soon, adding more nuclear plants to the portfolio makes it both more risky and less profitable, and would be undesirable. The markers along the lines show how much nuclear plant has been added, in steps of ten percent.

Moving from emissions trading to a carbon tax has the effect of rotating the portfolio line clockwise. The expected profits of any portfolio rise, as does the risk of a portfolio with a high proportion of CCGT plant (above 83%). A portfolio with more than 17% of nuclear plant, however, sees a reduction in the variance of its profits. The overall effect is to increase the range of the efficient portfolio line. This is the portion of the risk-return line that slopes up to the right, along which companies gain a higher expected profit in exchange for taking on more risk. Portfolios with a high proportion of nuclear plant are on the downward-sloping part of the line, and it is not efficient to take on more risk and simultaneously reduce your expected profits. With emissions trading, portfolios with up to 7% of nuclear power are on the efficient frontier, and might be chosen, depending on the company's attitude to risk. With a carbon tax, the efficient frontier includes portfolios with up to 18% nuclear power.

Whether a company wishes to diversify depends upon its attitude to risk. With λ = 0.1, a company would accept a portfolio consisting entirely of gas plants in an emissions trading system, but would want to have 10% of its capacity in nuclear power under a carbon tax. With less risk aversion, and lower values of λ, the company would reduce the proportion of nuclear power. With $\lambda < 0.046$, the optimal portfolio has no nuclear stations.[6]

---

[5] The appropriate value of λ depends upon the investor's wealth and their attitude to risk aversion. It is possible to use stock market data and Grinold's (1996) "grapes from wine" technique to estimate that UK investors would have a value of λ equal to 2.23 divided by their wealth, where wealth needs to be measured relative to the units in this model (here, kW of capacity) (Green, 2004). With profits of around £10/kW-year from the "inferior" technologies, and a discount rate of 10%, this could indeed produce a value for λ of very close to 0.02.

[6] An imminent extension to this paper will consider portfolios of coal, gas and nuclear plant.

6. CONCLUSION

This paper has used simulation methods to predict the mean and variance of the profits earned by different types of generators in a liberalised electricity market with different types of emissions policy. Using numbers appropriate for the UK in 2020, gas-fired stations appear to be both most profitable and to have the lowest variance of profits. This is due to the high correlation between their marginal costs and the price of electricity. It is likely to be self-reinforcing, since these characteristics make gas-fired stations more attractive to investors, and an increase in the proportion of gas-fired generation strengthens the link between the cost of gas-fired stations and the price of power.

Nuclear power stations have costs that are much less volatile than those of gas-fired stations, but their profits are lower and more volatile. If companies are sufficiently risk-averse, including nuclear power stations in a portfolio of plant could be worthwhile, given the negative correlation between nuclear and CCGT profits. The level of risk aversion required for this diversification argument to be effective, however, could be higher than that supported by estimates drawn from the UK stock market. A higher carbon tax, or more restrictive emissions trading scheme, could raise the profits of nuclear power, but will not reduce their volatility while wholesale prices are linked to the cost of gas. Long-term electricity sales contracts would be needed if the hedge that nuclear generation provides for the system's costs is to become a hedge for company profits.

References

Awerbuch, S. (2000) "Getting It Right: The real cost impacts of a renewables portfolio standard" *Public Utilities Fortnightly*, Feb 15, 2000, pp. 44-52

Department of Trade and Industry (2006) *The Energy Challenge: Energy Review Report 2006*, Cm 6887, London, The Stationery Office

Elders, I., G. Ault, G. Burt, J. Koehler, R. Tumilty and J. McDonald (2006) *Scenarios of the Electricity Industry in Great Britain in 2020: Networks, Generation and Decarbonisation*, mimeo, University of Strathclyde

Evans, J.E. and R.J. Green (2005) *Why Did British Electricity Prices Fall After 1998?* Department of Economics Working Paper 05-13, University of Birmingham

Gabriel, S. (2006) *Germany remains at the forefront of climate protection*, downloaded from Federal Ministry for the Environment, Nature Conservation and Nuclear Safety web site on 26 July 2006, http://www.bmu.de/english/emissions_trading/current/doc/37401.php

Green, R.J. (2004) *Retail Competition and Electricity Contracts*, CMI Working Paper EP33, University of Cambridge

Green, R.J. (2005) "Electricity and Markets" *Oxford Review of Economic Policy*, vol. 21, no.1, pp. 67-87

Green R.J., and D.M.Newbery (1992) "Competition in the British Electricity Spot Market" *Journal of Political Economy* 100 (5), October, pp 929-53

Grinold, R.C. (1996) "Domestic grapes from imported wine", *Journal of Portfolio Management*, vol 26, special issue (December), pp 29 - 40

Klemperer, P. D. and M.A. Meyer (1989) "Supply Function Equilibria in Oligopoly under Uncertainty," *Econometrica*, vol. 57 no. 6, pp 1243-1277

Newbery, D.M. (2002) "Problems of liberalising the electricity industry" *European Economic Review*, vol. 46, pp 919-927

Newbery, D.M. (2006) *Climate change policy and its effect on market power in the gas market* Electricity Policy Research Group working paper EP06/06, University of Cambridge

Roques, F.A., W. J. Nuttall and D.M. Newbery (2006a) *Fuel-mix diversification incentives in liberalized electricity markets: a Mean-Variance Portfolio Theory Approach*, mimeo, University of Cambridge

Roques, F.A., W. J. Nuttall and D.M. Newbery (2006b) *Using Probabilistic Analysis to Value Power Generation Investments Under Uncertainty*, Electricity Policy Research Group working paper EP06/19, University of Cambridge

Roques, F.A., W. J. Nuttall, D.M. Newbery, R. de Neufville and S. Connors (2006c) "Nuclear Power: a Hedge against Uncertain Gas and Carbon Prices?" *The Energy Journal* vol. 27 no. 4, pp 1-23

Sijm, J., K. Neuhoff and Y. Chen (2006) "CO_2 cost pass-through and windfall profits in the power sector", *Climate Policy*, vol. 6 no. 1, pp.47-70

Twomey, P. (2005) *The non-CO2 benefits of renewables*, presentation to the Electricity Policy Research Group Spring Seminar, May 2005, available from http://www.electricitypolicy.org.uk/events/spring05/programme.html

Weitzman, M.L. (1974) "Prices versus quantities" *Review of Economic Studies,* vol. 41 no.4, pp. 477-91

Figure 1: Industry supply function - DTI Base Case

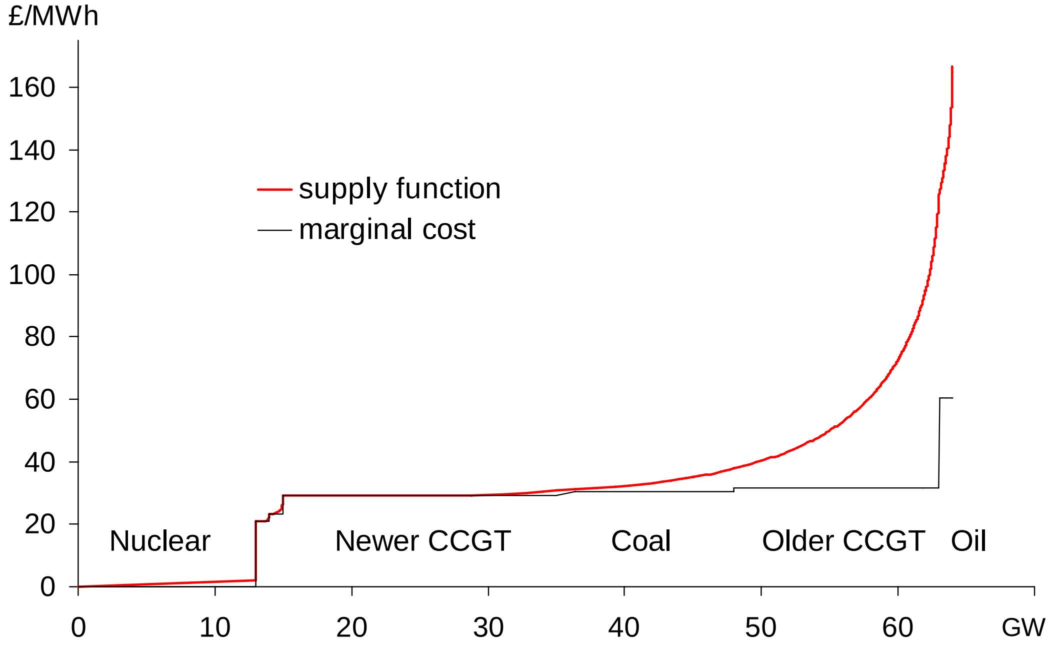

Figure 2: Profits with carbon emissions permits

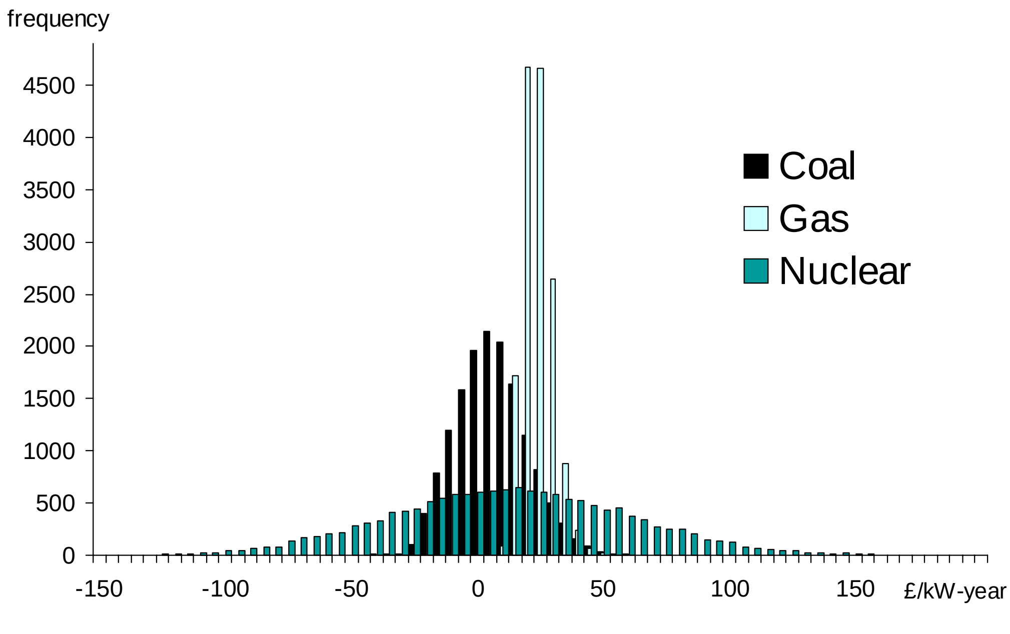

Figure 3: Profits with a carbon tax

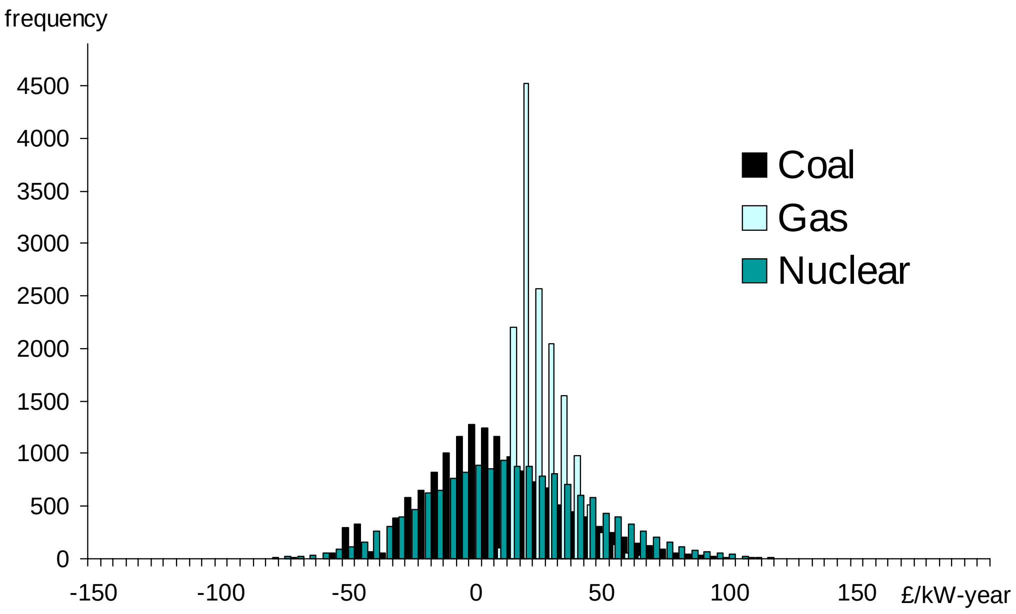

Figure 4: Portfolios of plant