Why did British electricity prices fall after 1998?

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Abstract

In an attempt to reduce high electricity prices in England and Wales, the government and regulator forced the largest generators to divest some plant in the late 1990s, and introduced New Electricity Trading Arrangements in March 2001. We use a supply function model to simulate prices from April 1997 to March 2004, and find no change in the relationship between our simulations and actual prices over this period. This implies that while the reduction in concentration has had a significant impact on short-term wholesale electricity prices, the switch from a centralised to a decentralised market has not.

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1. INTRODUCTION

It is a truth universally acknowledged, that an electricity market with high prices is in want of a remedy. The causes of high prices include insufficient generation capacity, market power stemming from excess concentration among generators, and inappropriate market rules. The natural remedies are, in turn, to encourage the addition of more generation capacity, to negotiate or impose a more competitive market structure, and to change the market rules. In England and Wales, electricity prices in the second half of the 1990s were persistently above the costs of new entrants. Towards the end of the decade, more capacity was added, and two of the largest generators divested a significant proportion of their plant. On March 27, 2001, a new set of trading rules came into force. In the following years, wholesale prices were 40% lower than when the industry's regulator first suggested reforming the trading system.

England and Wales have thus experienced all three of the classical remedies for high electricity prices. This paper is an attempt to assess which of those remedies had the greatest impact on the level of short-run prices for electrical energy. In particular, we hope to shed light on the extent to which the adoption of the New Electricity Trading Arrangements (NETA) directly caused the drop in wholesale prices which occurred at about the same time. One of the major justifications for the change, which was estimated to cost £600 million to implement (NAO, 2003), was that the previous market had been uncompetitive, and that NETA would provide more cost-reflective prices.

We use a simulation model to create a price series from April 1997 to March 2004, which includes four years before the change in trading arrangements and three years afterwards. We use actual data for fuel prices and the capacity and ownership of power stations, and for the quantities demanded in each month. We use exactly the same model of competition before and after NETA. If our model is able to predict prices accurately before the introduction of NETA, and NETA made competition more intensive, then we would expect that our model would over-predict prices after NETA came into effect. In fact, we will show that our model does a good job of predicting prices both before and after the change in trading arrangements. The most straightforward explanation of this is that NETA did not change the way in which market fundamentals – costs and capacities – were translated into prices. Any alternative explanation relies on our model breaking down in the face of market conditions corresponding to those at the time NETA was introduced, so that it would have given an inaccurate estimate of prices under the continued operation of the Pool. That inaccuracy would need to be equal, and in the opposite direction, to the impact of NETA. By Occam's razor, we prefer to discount such coincidences.

The next section of the paper considers the history of the electricity industry in England and Wales and the decision to introduce NETA. Section 3 considers some of the prior academic work on market power in the electricity industry. Section 4 introduces the supply function model that we use to simulate prices over our seven-year period, and section 5 discusses its calibration. Section 6 presents the comparison of the actual market prices with our simulations. Section 7 discusses a number of counter-factual scenarios which we have run to explore the impact of other changes to the market which happened in the run-up to NETA, and section 8 concludes.

2. THE ELECTRICITY INDUSTRY IN ENGLAND AND WALES

The electricity industry in England and Wales was restructured on March 31, 1990. The state-owned Central Electricity Generating Board (CEGB) was divided into the National Grid Company (NGC), responsible for transmission, and three generating companies. Two of these, National Power and PowerGen, with 50% and 30% of the industry's capacity respectively, were privatised in February 1991. Nuclear Electric owned almost all of the remainder, but was kept in state ownership, as its nuclear reactors were believed to be too expensive to privatise. A failed attempt to privatise the nuclear stations had been the main motive for creating a company as large as National Power, in the hope that it would be large enough to absorb the risks of nuclear power. The stations had to be withdrawn from the sale in November 1989, and there was not enough time for significant changes to the restructuring plan.

The centre-piece of the restructuring was a spot market known as the Pool. Each day, this accepted bids from all the generators, and used a version of the CEGB's cost-minimising software to draw up an operating schedule and to calculate the System Marginal Price (SMP) for each half-hour. This was broadly equal to the average bid cost of the marginal station in each half-hour. Generators received the SMP for every unit of output that they were scheduled to generate, and received a capacity payment for every MW of available capacity. This payment was equal to the Loss of Load Probability multiplied by the net Value of Lost Load.

The cost of deviations from the schedule, due to forecasting errors, plant failures, and transmission constraints, of making capacity payments to generators who had not been scheduled to generate, and of buying ancillary services such as reserve, were recovered in a charge called Uplift. Uplift was added to the Pool Purchase Price to give the Pool Selling Price (PSP), payable by all suppliers for every unit that they bought through the Pool.

Legally, almost all electricity had to be traded through the Pool, although in practice, most of it was hedged with contracts for differences, which allowed generators to "lock in" their revenues in advance. In 1990, most of the generators' sales were hedged with three-year "coal-related" contracts at relatively high prices, above the expected level of Pool prices. This was because Pool prices were expected to be related to the marginal cost of generating using imported coal, while the generators were contracted to buy large quantities of British coal at higher prices. The coal-related contracts passed the difference in cost on to the Regional Electricity Companies (RECs), which were in turn allowed to pass the cost on to their (captive) smaller customers.

In its first year, Pool prices (shown in figure 1) were lower than expected, in part because the generators were competing to burn as much coal as possible. Over the following years, however, average Pool prices rose significantly, while there were suggestions that the generators were "gaming" particular aspects of the rules to increase their revenues. The industry's regulator issued a series of reports which criticised some aspects of this behaviour, but conceded that while prices were below the major generators' avoidable costs, it was reasonable for them to increase. By July 1993, however, the regulator concluded that prices had now risen above the level of the generators' avoidable costs, and announced that he would decide whether he should refer them to the Monopolies and Mergers Commission (MMC).

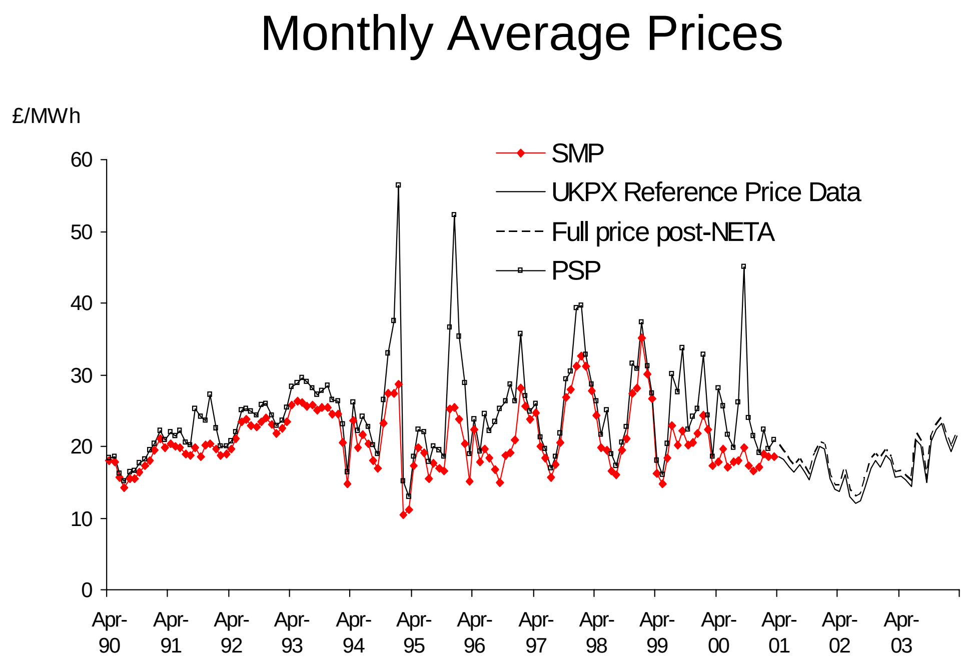

Figure 1

In February 1994, he announced that he had decided not to refer the companies to the MMC, at least for a two-year period. This was because they had given him undertakings to sell or otherwise dispose of 6 GW of plant, and to keep prices below a specified level during 1994/5 and 1995/6, while the sales were being arranged. National Power eventually leased 4 GW of plant to Eastern Electricity, while PowerGen leased 2 GW. Eastern had agreed to pay an "earn-out" of £6/MWh for each unit that the leased stations generated, which raised its bids, while the company also proved adept at exploiting loopholes in the Pool rules to increase its revenues. The flow of reports from the regulator continued.

In the autumn of 1997, it became clear that the demand for coal was due to fall significantly when the second round of "coal-related" electricity contracts expired in April 1998. The expiry of the first round had provoked a political crisis for the Conservative government of the day, while the new Labour government had strong emotional ties to the coal industry. Coal had been displaced by the new CCGTs, and the high level of wholesale prices continued to encourage entry, even though the avoidable costs of the displaced coal stations were arguably lower than those of the CCGTs replacing them.[1] A temporary moratorium on new gas-fired stations gave the coal industry some hope, while the regulator was asked to conduct a review of electricity trading arrangements, to examine whether these had been responsible for some of the problems in the industry.

The review concluded that the Pool had a large number of faults, and that it should be replaced by New Electricity Trading Arrangements (NETA) (Offer, 1998). The Pool's single-price rule was argued to make it easier for generators to exploit their market power, since they could submit low bids for part of their capacity, guaranteeing that it would run, while a small number of high bids would set the price for the whole market. This price umbrella had also

[1] Until the decision to build a new station has been made, practically all of its costs are avoidable, unlike the capital costs of an existing coal station.

encouraged the entry that was driving down the demand for coal. The Pool's complexity had created many opportunities for gaming, while the market's compulsory nature went against the principle of freedom of choice. These arguments were not uncontroversial (see e.g. Newbery, 1998b, Green, 1999a), but were accepted by the government.

The Department of Trade and Industry and the regulator (now called Ofgem) together created the New Electricity Trading Arrangements, based upon bilateral trading and a balancing mechanism to keep the system stable in the last few hours before real time. The balancing mechanism was the only centrally-designed market, and more than 95% of electricity is traded on over-the-counter markets or power exchanges. Traders have to notify NGC of their intended physical position at "Gate Closure", originally set 3½ hours before real time, but brought forward to one hour before real time in July 2002. Generators and suppliers submit bids and offers to adjust those positions, and NGC keeps the market in balance by accepting some of these. The average cost of the accepted bids (to buy power from NGC) is the System Sell Price (SSP), while the average cost of the accepted offers (to sell additional power to NGC) is the System Buy Price (SBP). On average, the System Buy Price is much higher than the System Sell Price. After the event, the Balancing and Settlement Company, Elexon, compares every firm's contractual position with its physical position. Companies which were short of power have to buy some at the System Buy Price, while those with a surplus are paid the System Sell Price. Companies with supply and generation have separate imbalances for each side of their business. Because the System Buy Price is generally much higher than the System Sell Price, imbalances are costly, which was intended to give participants an incentive to balance their positions before Gate Closure. In practice, companies seem to have been anxious to minimise their exposure to the System Buy Price, which is much the more volatile, and have generally had a surplus of power at Gate Closure, rather than a balanced position.

The government and the regulator hoped that changing from the Pool to NETA, which finally took effect on March 27, 2001, would in itself reduce the generators' market power. There were other developments in the run-up to the new market's introduction, however. In June 1998, the regulator had recommended that the major generators should be required to divest more of their plant, and the government had accepted this recommendation in its response to the NETA proposals. PowerGen offered to divest 4 GW of plant if it was allowed to acquire East Midlands Electricity, and National Power was required to divest 4 GW in return for acquiring Midlands Electricity's supply business. Both companies followed these sales with others that were completely voluntary, however. They may have expected prices to fall in future, and preferred to sell plant at prices that seem not to have reflected these expectations. These divestitures, and later sales, are shown in figure 2.

Capacity by firm

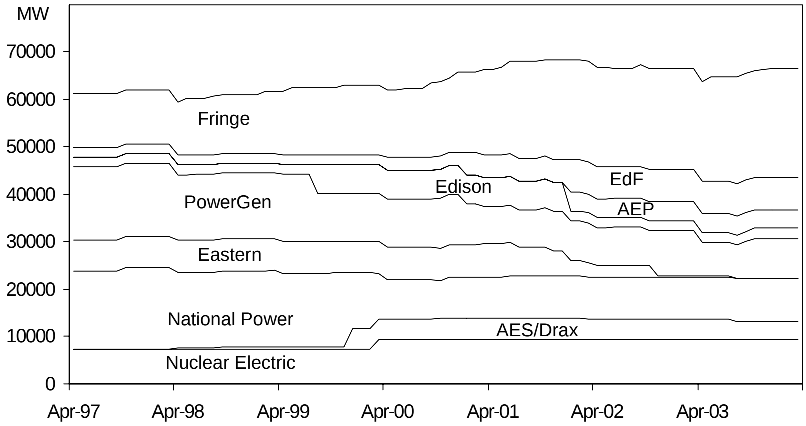

Figure 2

National Power divided itself into two companies, Innogy (with most of the UK assets) and International Power (with one UK power station and the company's overseas assets). Innogy subsequently bought two more REC supply businesses (Yorkshire and Northern). Eastern Electricity, which had been renamed TXU, bought a second supply business (Norweb), as did London Electricity, owned by Electricite de France, which purchased SWEB. British Energy, which had been privatised with the more modern nuclear plants in 1996, started to move towards vertical integration by acquiring Swalec's supply business, but sold the business within two years, realising that it was unlikely to acquire the five million customers generally believed to confer minimum efficient scale. The company bought a 2 GW coal-fired station instead, to help in balancing its inflexible nuclear stations. Swalec's supply business was acquired by Scottish and Southern Energy, which combined Southern Electric and Hydro-Electric.

There were further transactions after the start of NETA. London Electricity took over Seeboard, the last REC supply business not to be part of a larger group. TXU Europe pulled out of the UK market in the autumn of 2002, having bought power at what turned out to be uneconomic prices. Its supply businesses were bought by PowerGen, while its power stations were acquired by PowerGen, Centrica and International Power. TXU's problems, and low wholesale prices more generally, caused financial distress to a number of other unintegrated generators – in particular, AES walked away from its investment in Drax, which it had bought from National Power in 1999. Several other independent stations have been acquired by the integrated companies, and there has been a gradual increase in concentration from its low point in early 2001. Academic work on electricity markets suggests that the level of concentration is likely to have a major impact on prices.

3. MARKET POWER IN ELECTRICITY

The first studies of market power in the British electricity markets were written soon after those markets were established. Green and Newbery (1992) argued that an electricity pool could be modelled as if generators competed by submitting supply functions, and showed that the equilibrium of this model in a concentrated industry would imply prices well above marginal costs. Von der Fehr and Harbord (1993) produced similar conclusions using an auction approach. Their results draw out an explicit link between the amount of spare capacity in the industry and the level of prices: prices will be much higher if neither firm is capable of meeting demand on its own.

Wolfram (1998, 1999) studied bids and prices in the England and Wales market. She found that the mark-ups between price and marginal cost were higher when demand was above the median level, and that generators tended to submit higher bids, relative to marginal costs, the greater the level of capacity that was infra-marginal to the bidding plant. Sweeting (2004) finds that mark-ups in a given quarter are generally higher when there is little spare capacity. He finds that mark-ups vary over time, however, and relates this to changes in concentration and to collusion. In particular, he suggests that generators changed their behaviour from not exploiting their (considerable) market power in the mid-1990s to exploiting the (much lower) degree of market power that remained to them, and possibly even colluding[2] by the end of his sample period in 2000.

There are a number of theoretical studies of the impact of different market rules. Bower and Bunn (2000) used a simulation model to predict that moving from a daily auction with a uniform price to hourly auctions with discriminatory pricing (i.e., from a simplification of the Pool system to NETA) would lead to higher prices. Fabra (2003), however, shows in a theoretical model that a discriminatory auction is less vulnerable to the exercise of market power than a uniform-price auction is. The uniform-price auction allows generators to receive a high price while still submitting low bids, and therefore minimising the pay-off from deviating to a more competitive strategy. Fabra et al (2004) compare several auction formats and find that their welfare ranking is ambiguous – uniform price auctions are (weakly) more efficient, but a discriminatory auction is (weakly) better for consumer surplus. In other words, the switch to NETA might be expected to reduce prices.

Once NETA had taken effect, it was obviously possible to conduct empirical studies, and we are aware of three. Bower (2002) regressed monthly average price data from 1990 on fuel prices, measures of concentration in different plant types, and a number of variables to reflect regulatory interventions between 1990 and 2002. Most of these are dummy variables, but he also uses the volume of coal covered by government-backed contracts between 1990 and 1998. He adopts a general to specific methodology, deleting variables that turn out to be insignificant.[3] He finds that changes in concentration, and in particular the divestment of coal plant, had a large impact on prices, as did the Price Undertakings of 1994-6 (which reduced SMP), and the gas moratorium of December 1997-October 2000 (which raised PSP). His results suggest that PSP was reduced by the introduction of NETA (because Capacity Payments were abolished), but that SMP apparently rose. He concludes that the costs of introducing NETA outweighed the benefits, given that capacity disposals could have been accomplished at a relatively low cost, and assuming that Capacity Payments might have been cheaply abolished while leaving the rest of the Pool's arrangements intact.

Evans and Green (2003) used estimated marginal costs in place of fuel prices, and then found that the Lerner index (price minus marginal cost, divided by price) performed better as a dependent variable. We found no impact of NETA at the time when it was introduced, but did find a statistically and economically significant reduction in prices when a dummy

[2] By colluding, Sweeting implies that the generators were producing less output than would have been privately profitable in a one-shot game, given their costs and the bids submitted by the other market participants.

[3] The Price Undertakings of 1994-6 (which reduced SMP), and the gas moratorium of December 1997-October 2000 (which raised PSP), together with the volume of coal contracts, were regulatory dummies that proved significant in the regressions most comparable to ours.

variable was introduced six months beforehand. The anticipated changes in market rules might have disrupted a pattern of tacit collusion (which is consistent with behaviour observed by Sweeting (2004)), so that the price reductions could have been an indirect result of NETA. We did not run any econometric tests to establish the best timing for the start of our dummy variable, however.

Fabra and Toro (2003) use Bai and Perron's (1998) methodology to find a structural break in the Lerner index. This is estimated to occur in November 2000, but with a confidence interval running from May 2000 to April 2001. They interpret this result, and subsequent regressions, as supporting the view that NETA helped to reduce prices.

One weakness in all three studies is that they look for a relatively straightforward relationship between concentration and prices. Bower looks for a linear relationship between various Herfinahl indices and prices, Fabra and Toro for a linear relationship between the HHI and the Lerner index, and we sought a quadratic relationship between the HHI and the Lerner index. It is clear that the relationship between concentration measures and electricity prices can be much more complex than this, as discussed by Borenstein and Bushnell (1999).

The alternative to regression analysis is simulation. Recent work by Burns et al. (2004) and by Bushnell et al. (2004) shows that simulation models incorporating strategic behaviour can recreate electricity prices with a high degree of accuracy. Burns et al. use a scheduling model based upon a mixed integer program incorporating unit commitment and dynamic constraints in order to calculate marginal costs. They use a simpler version of the model to calculate the prices, costs, quantities and profits resulting from a generator bidding at marginal cost, twice marginal cost, three times marginal cost, and so on (up to seven times marginal cost). They then find the strategy combinations that form a Nash equilibrium, and record the resulting prices. Regression analysis shows that these are good predictors of Pool prices. Burns et al start a new simulation (and regressions) each time the number of companies with sufficient plant to be considered strategic players changes, which limits the length of their time series.

Bushnell et al. ran simulations of three US markets – New England, California and PJM – in the summer of 1999. For each market, they run a competitive simulation, in which all the firms act as price-takers, and a Cournot simulation, in which each strategic firm sets quantities, taking its rivals' output as given in each hour. They present most of their results in the form of kernel regressions of simulated and actual prices, relative to the level of demand. The regression lines for the actual prices are generally close to their Cournot simulations, and well above the price-taking simulations. Their main set of simulations adjusted the strategic firms' profit functions (where appropriate) for vertical integration between generators and retailers, given that retail rates in most markets were fixed at this time. A set of simulations that did not make these adjustments produced prices that were far too high at almost all demand levels.

The aim of these papers is essentially to check the performance of the simulation models, presumably with an eye to using them to make future predictions. Our aim, as described above, is to find a simulation model that accurately reflects prices before NETA, and to see whether the relationship between actual and estimated prices changes when NETA takes effect. We describe our model in the next section.

4. A SUPPLY FUNCTION MODEL

We use a supply function model to produce our simulated price series. 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. 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:[4]

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

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:

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

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. Klemperer and Meyer show that if the firms are symmetric, and the range of possible demand curves is wide enough,

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

then no asymmetric supply function equilibrium will exist – at least one of the curves will slope downwards over part of its range. If the firms are symmetric, however, the range of potential supply functions is wide, although it narrows as the variation in demand increases.

A corollary of the lack of asymmetric supply functions among symmetric firms is that it is very hard to find the supply function equilibria for asymmetric firms. With symmetric firms, the equilibria must lie on the surface given by $q_i = q_j$ in (q_i, q_j, p) space. With asymmetric firms, Green (1995) suggests that the equilibria also lie on a single surface, but one that is not described by a simple equation. There is no doubt that asymmetric equilibria exist, since Laussel (1992) and Green (1996) provide analytical formulae for linear equilbria in the case of linear costs and demand. Unless the modeller wishes to accept the restriction of linear supply functions,[5] empirical modelling of asymmetric firms therefore depends upon finding this surface. At present, that requires a process of trial and error, which does not lend itself to automation and would be infeasible for repeated simulations involving more than two firms.

Green and Newbery (1992) modelled two asymmetric generators as if they were symmetric, each with half of the industry's conventional capacity. They had compared the results for overall prices, quantities and profits with the results from the asymmetric case, and there was little difference between the two. We will follow their approach, and model the industry as if it contained $\hat{n}$ symmetric strategic generators, together with a competitive fringe. In each month, $\hat{n}$ is the inverse of the Herfindahl index, calculated using the capacity of the strategic generators. We do not restrict $\hat{n}$ to be an integer, since we will be using the industry's aggregate supply function and are not interested in firm-by-firm results. Our supply functions are thus given by the differential equation:

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

For the case of linear marginal costs, it is possible to calculate linear supply functions exactly, and compare their price predictions with those given by the industry supply function obtained by this method. We do so in the appendix to this paper. When the industry's capacity is divided between relatively symmetric firms, as from 2000 onwards, the two methods give price predictions that are within 0.2% of each other. When the distribution of capacity is uneven, our $\hat{n}$-firm approximation gives prices that are around 2% higher than the exact method. Note, however, that these linear supply functions do not take capacity constraints into account. In reality, the smaller firms would reach their capacities at lower prices than the larger firms, and those larger firms would submit steeper supply functions above those prices, as discussed by Baldick *et al.* (2004). In other words, while our $\hat{n}$-firm approximation may give slightly higher prices than the asymmetric linear supply function model, that model may under-predict prices. We do not have a comparison between our approximation and the true asymmetric functions for the non-linear case. We will show below, however, that our model gives reasonable simulations of actual prices, and, following Friedman's (1953) methodology, argue that this makes it an appropriate model to use.

[5] Green (1996) and Baldick *et al.* (2004) have used linear supply functions to model the English electricity market, but we wish to obtain more accurate results than a linear approximation allows.

5. CALIBRATION

The aim of this paper is to compare simulated and actual prices in the day-ahead market for electrical energy. It is straightforward to obtain data for Pool prices, and we use the time-weighted monthly average of the System Marginal Price from April 1997 until March 2001. The closest equivalent to Pool prices under NETA is the UKPX Reference Price Data,[6] which gives an average of the prices in the UKPX's market, operating in the last day or so before real time. We reduce the post-NETA prices to reflect the fact that suppliers now only pay 55% of transmission losses. Under the Pool, their metered demands were scaled up by an average of 1.5% so that metered demand (on the transmission system) equalled metered generation, and the Pool Selling Price was applied to this scaled demand. Under NETA, demand is scaled by little more than half this amount, reducing the effective cost to suppliers.

We are not modelling Capacity Payments, which did contribute significantly to the level and volatility of Pool prices. In the Pool's last years, high Capacity Payments occurred at times when there appeared to be more than enough capacity, and helped to bring the market into disrepute. Generators' price bids had little impact on the level of Capacity Payments, however, and it would have been possible to abolish Capacity Payments while retaining the rest of the Pool, at a much lower cost than the introduction of NETA.

To calculate the supply functions, we need to know the industry marginal cost curve. We have data on the monthly registered capacity of power stations in England and Wales, and on the monthly cost of fuel. We use the price paid by Major Power Producers for gas and for oil, as reported in Energy Trends. For the period up to March 2002, we use a three-month moving average of the Eurostat figures for the cost of imported coal. We believe that the import cost is a better reflection of the marginal cost of coal in the first part of this period than the average price paid by the major power producers, which reflected a series of high-price contracts agreed under government pressure to support the coal industry. By 2002, however, the average price paid by the Major Power Producers had converged with the Eurostat data, and so we have switched to the Energy Trends figures. We assume thermal efficiencies of between 31% and 37% for coal stations, 43% and 53% for CCGTs, and 36% for oil stations. To account for the "earn-out", we added £6/MWh to the marginal cost of the stations that Eastern leased from the major generators during the relevant periods. In the case of the 2 GW of ex-PowerGen stations, this was until March 2000 (inclusive), while in the case of the 4 GW of capacity leased from National Power, the earn-out lasted until December 2000.

We do not attempt to adjust the capacity of fossil-fuelled stations for actual availability, since this was potentially a strategic variable for the generators, but scale back the registered capacity of fossil stations by between 10% (winter) and 20% (summer) to account for outages. We do have the actual figures for nuclear output, however, and use these. The cost structure of nuclear stations was such that withholding output was never an attractive option for their owners. We do, however, include the coal-fired plant currently owned by British Energy among the plants owned by strategic generators.

Our strategic generators are National Power, PowerGen, TXU/Eastern, Electricite de France/London, AES, Edison, AEP, British Energy (Eggborough only) and Drax Power. There was no month in which all of these companies had significant market shares. For example, AEP only became a significant generator in the UK once it had acquired 4GW of coal-fired plant from Edison, which naturally reduced the latter's market share. Drax Power only came into existence once the station was abandoned by AES, and that only happened because of TXU's withdrawal. However, changing the set of strategic generators over time could create inconsistencies in the supply functions. We therefore consider all of these

[6] UKPX Reference Price Data is used under licence agreement with APX Power Limited. The UKPX is the UK Power Exchange, the leading short-term market for electricity in England and Wales.

companies as strategic bidders throughout the time period, even if they have very little capacity. We calculate a supply function for the strategic firms, and assume that the capacity owned by non-strategic firms is offered at marginal cost.

We use a constant demand slope of -100 MW per £/MWh to calculate our supply functions. With a range of demand curves, the elasticity of demand varies, but the average value, based on the retail price of power, is just under -0.1. We do not subtract the non-strategic firms' output from this demand curve. Since their supply curve is a step function, a complete analysis would have to allow the strategic firms to recognise that this creates large discontinuities in their residual demand curve, and to take advantage of these in designing their supply function. In practice, however, the strategic firms seem not to have taken advantage of such discontinuities (which generally occur at low prices, in any case) and our calculated supply functions produce realistic prices. The functions are calculated numerically, starting with the highest price that could be bid by the strategic generators' most expensive plant (that is, the price that would give a vertical supply function for that level of output). The algorithm then reduces the price, uses the previously calculated slope (initially zero) to find the new level of output, and calculates the slope of the supply function at that point. The algorithm ensures that the slopes are always positive, and that the price exceeds marginal cost and is less than the highest admissible price for the current level of output.[7]

Figure 3 shows the strategic firms' supply function for January 1998, and figure 4 shows the strategic firms' supply function for January 2003. Comparing the two, the marginal cost curve has shifted inwards (National Power and PowerGen had closed plant over the period) and upwards (fuel costs have risen). The supply function is much closer to the marginal cost curve in January 2003, because the industry has become more competitive – the Herfindahl index among the strategic firms has fallen from 0.306 to 0.189. The maximum and minimum demand curves, net of the appropriate equilibrium level of output from the price-taking firms, are also shown on each graph.

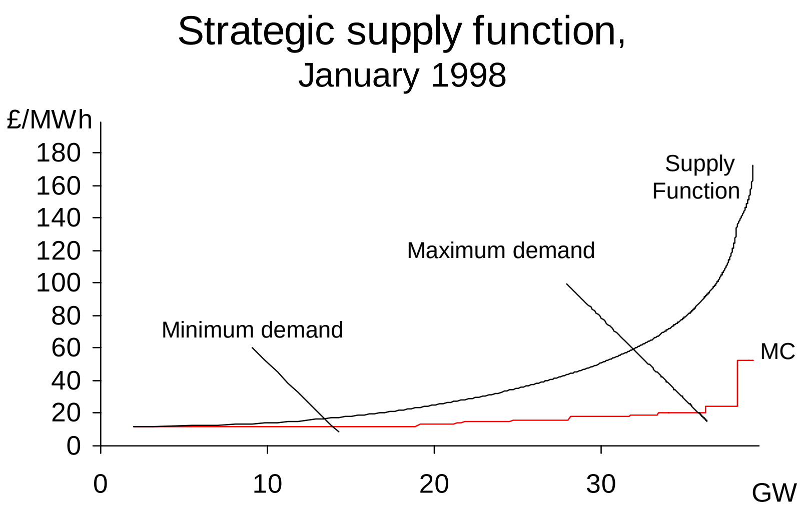

Figure 3

[7] This maximum price is the price that would be charged in a Cournot equilibrium for this level of output and demand curve. It is equal to the firm's output, divided by the slope of the demand curve, plus its marginal cost. The bounds on permissible supply functions are discussed at greater length by Klemperer and Meyer (1989) and by Green and Newbery (1992).

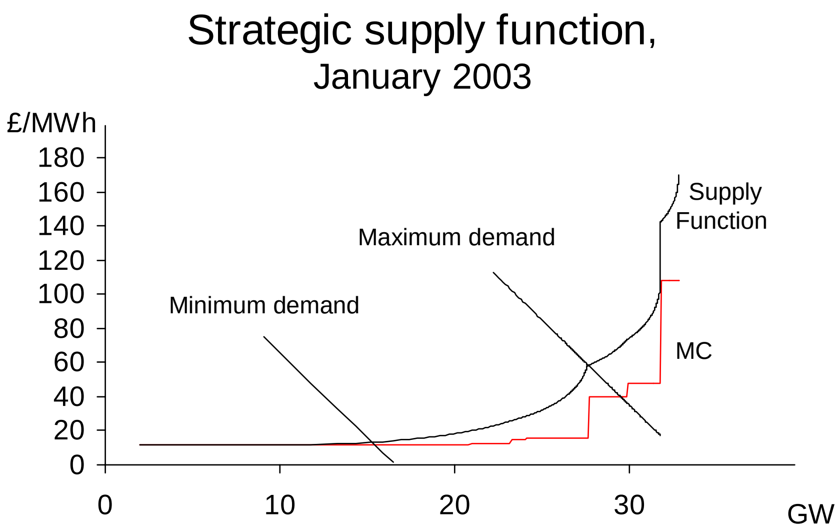

Figure 4

We use twenty-one demand curves for each month, based on the monthly peak demand, the 5th percentile, 10th percentile, and so on. These quantities were combined with the corresponding percentiles of the price,[8] each averaged across all the months in the sample, to anchor the demand curves. We have used averaged prices to ensure that random factors that raise the price relative to demand in a particular month do not affect our simulated price series – otherwise, the errors in our main independent variable would be correlated with those in our dependent variable. Having calculated the equilibrium price for each demand curve, we take the unweighted average for our simulated price series.

We have two other explanatory variables. One is a Herfindahl index for overall capacity ownership, including both strategic and non-strategic firms. This turned out to perform poorly and was not included in our reported regressions. The second is the ratio of average demand during the month to registered capacity. The first variable is intended to pick up the effect of competition on prices, while the second is intended to capture the effect of the level of spare capacity available.[9]

We have 84 monthly observations from April 1997 until March 2004. Price behaviour in the very early years of the Pool was dominated by the effects of the coal contracts. Prices between April 1994 and March 1996 were distorted by the generators' undertaking on Pool prices, and the generators seem to have attempted to keep prices at the same level in 1996/7. With high capacity payments, this required low levels of the System Marginal Price, our measure of prices. From April 1997 onwards, capacity payments were lower, and energy prices seem to have been set more freely as seen in figure 5. We therefore use this as the start of our dataset. Descriptive statistics of the data that we use are set out in Table 1.

[8] We used the 2.5th and 97.5th percentiles as our highest and lowest prices, to reduce the impact of extremes.

[9] It is not equal to the ratio between available capacity (controlling for strategic behaviour) and peak demand during the month, which would form the basis for our "ideal" regressor, but should be closely related to it.

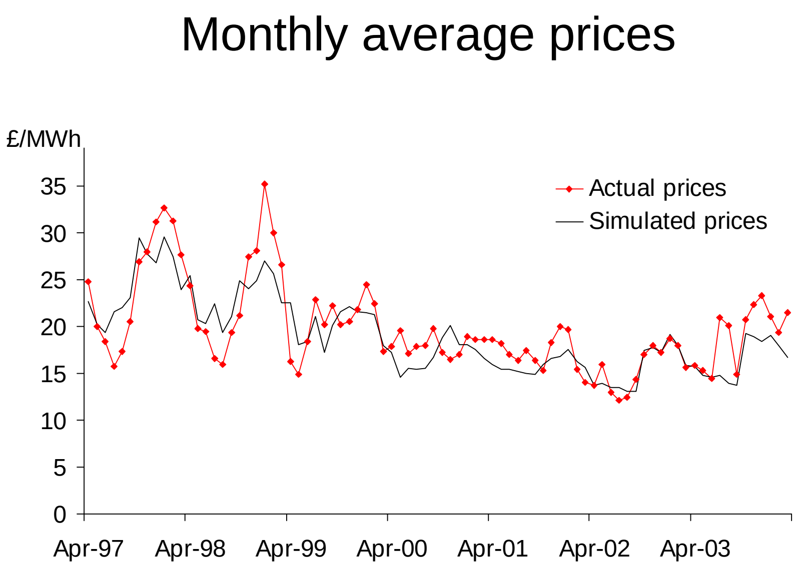

Figure 5

Table 1 Descriptive Statistics April 1997 – March 2004

Variable	***Mean***	***Standard Deviation***	***Min***	***Max***
Demand/ Capacity	0.5370	0.0520	0.4517	0.6183
Supply Function	18.96	4.0506	13.03	29.56
Price	19.74	4.7363	12.10	35.17

6. SIMULATING THE ACTUAL PRICES

Figure 5 shows our simulated price series against the actual monthly averages, and the two series clearly tend to move together. We test the performance of our simulations more formally by regressing the simulation against the actual prices. One regression uses the simulation alone – if the simulation is a good one, we would expect a high adjusted R^2 and a coefficient of close to one. We then include a constant term, and finally a series that takes the ratio of the average demand level during each month to the total capacity in that month. This should pick up seasonal factors, given that demand is much higher in the winter than the summer in the UK. Inspection of figure 5 shows a distinct seasonal pattern to prices for the first two years of our sample, and also shows that the simulated price series have a less pronounced seasonal pattern during these years. These seasonal patterns are much less marked in the rest of the sample. Our initial estimates showed strong signs of autocorrelation, so we include an AR(1) term in the regressions (performed in Eviews 5.0). Our full equation is therefore:

$$\begin{aligned} Price_t &= \alpha_t + \beta_1 sf_t + \beta_2\, demcap_t + u_t \\ u_t &= \rho u_{t-1} + \varepsilon_t \end{aligned} \tag{6}$$

We present the results of all three regressions in Table 2. The performance of the three specifications is very similar, with an adjusted R^2 of around 0.75, and similar values of the Schwarz and Akaike information criteria. The regression using the simulated price series alone demonstrates that this gives a good prediction of the actual price – the coefficient is statistically indistinguishable from 1.0. This regression also has a slightly lower autocorrelation coefficient and a slightly higher Durbin-Watson statistic, suggesting marginally less serial correlation in the residuals. Adding a constant term makes little difference to the statistical fit of the regression, nor does including the ratio of demand to capacity. We believe that this variable improves the regression's fit over the first two years, when it picks up the seasonal pattern of prices, but then worsens it over the remaining five years, when this seasonal pattern practically disappears.

Table 2: Regression results on Actual Price: April 1997 – March 2004

	Coefficient	*SE*	*P-value*	*Coefficient*	*SE*	*P-value*	*Coefficient*	*SE*	*P-value*
Constant	-5.1968	4.1907	0.2186	3.7556	2.2048	0.0923			
Simulated Price	0.6903	0.1296	0.000	0.8453	0.1127	0.000	1.0317	0.0281	0.000
Demand/Capacity	22.0809	9.1387	0.0180						
AR(1)	0.5390	0.0974	0.000	0.5560	0.0945	0.000	0.5291	0.0957	0.000
Adjusted R^2	0.7692			0.7554			0.7498		
SEE	2.2752			2.3425			2.3691		
Durbin Watson	1.7537			1.7522			1.8131		
Akaike 1974 (AIC)	4.5284			4.5753			4.5864		
Schwarz 1978-(SC)	4.6442			4.6622			4.6443		
Sample size	84			84			84		

The way in which the seasonal differences between actual prices and our simulation disappear over time suggests that there could be structural breaks in the relationship. We therefore followed Bai and Perron's procedures (1998, 2003) for testing for an unknown number of structural breaks in the series, and report our results in table 3. If NETA changed the underlying relationship between concentration and market prices, we would expect the performance of our simulation to change, and this would be reflected in a structural break. The most obvious timing for such a break would be at the time when NETA was introduced, at the end of March 2001. It is also possible however, that the Pool had been characterised by tacit collusion and that this broke down in the face of the imminent changes to the market, before they actually took effect. In this case, a structural break occurring between the decision to implement NETA and its introduction could be due to the change in market rules. The regulator's decision document was published in July 1998, while the government accepted the policy in October that year (DTI, 1998).

Table 3 Bai and Perron (2003) Tests for Structural Change with unknown dates

	SFE, Demcap, constant		***SFE + constant***		***SFE***	
Breaks	**BIC**	**LWZ**	**BIC**	**LWZ**	**BIC**	**LWZ**
0	1.9490	1.9731	2.0008	2.0249	2.0163	2.0283
1	2.0186	2.1650	1.9482	2.0946	1.9992	2.0923
2	2.0317	2.3019	1.9365	2.2067	1.9998	2.1745
3	2.0722	2.4677	1.9267	2.3222	1.9757	2.2328
4	2.0284	2.5509	1.9522	2.4747	1.9635	2.3036
5	2.0207	2.6721	1.9998	2.6512	1.8874	2.3112
6	2.0604	2.8426	1.9855	2.7677	1.9002	2.4085
7	2.1436	3.0588	2.0834	2.9987	1.9577	2.5513
8	2.2078	3.2586	2.1182	3.1689	2.0124	2.6921
Dates of Breaks Selected						
Sequential	None		None		None	
LWZ	None		None		None	
BIC	None		June 2003 $\begin{Bmatrix} \text{October 1998} \\ \text{March 1999} \end{Bmatrix}$		June 2003 $\begin{Bmatrix} \text{October 1998} \\ \text{March 1999} \end{Bmatrix}$ $\begin{Bmatrix} \text{November 1997} \\ \text{March 1998} \end{Bmatrix}$	

Table 3 gives the results. We report the number of structural breaks according to three criteria, the sequential test proposed by Bai and Perron (1998), the modified Schwarz Criterion which they ascribe to Liu, Wu and Zidek (1997) (LWZ), and the Bayesian Information Criterion which they ascribe to Yao (1988) (BIC). All three tests give the same result for our first regression, finding no structural breaks in the joint relationship between actual prices, our simulations, and the ratio of demand to capacity. The sequential procedure and the LWZ test also agree that there are no structural breaks in either of the other regressions. The BIC test, however, suggests that there could be three structural breaks when we regress actual prices against our simulation and a constant, and five when we regress actual prices against our simulation alone. We report the dates of these breaks in the order in which they appear – if a single break is selected, it would be in June 2003, while if two breaks are specified, they would be in October 1998 and March 1999.

There is no evidence for a structural break within eighteen months of the change in market rules. The structural breaks in October 1998 and March 1999 might be seen as evidence of an effect around the time that the decision to change the market rules was made, but inspection of figure 5 makes it clear that these breaks were due to a reduction in the seasonality of Pool prices, with little impact on their average level. While a reduction in the highest prices might be consistent with a NETA-inspired breakdown in tacit collusion, this would be inconsistent with the way in which off-peak prices rise relative to the simulation. We therefore reject the hypothesis that NETA caused a structural break in the relationship between actual electricity prices and our simulation. If a constant model of competition provides an equally accurate simulation of actual prices, both under the Pool and under NETA, the implication is that the change in market rules was not responsible for the undoubted fall in energy prices.

7. COUNTER-FACTUAL SIMULATIONS

If NETA did not reduce electricity prices in England and Wales, what did? Intuitively, plant sales by the major generators, and additional entry, seem the most likely candidates. To assess the impact of these developments, we have used our model to simulate prices with a number of counter-factual assumptions.

Our first counter-factual assumes that there would have been no voluntary divestitures in 1999-2000. In other words, National Power (or rather, Innogy) would still be the owner of Eggborough (2 GW coal) and Killingholme NP (0.7 GW gas), while PowerGen would still own Cottam (2 GW coal) and Rye House (0.7 GW gas). The regulatory divestitures agreed in exchange for permission to integrate did go ahead, however.

Our second counter-factual assumes that there would have been no divestitures at all from 1999. National Power retains Drax (4 GW, coal) and Deeside (0.5 GW, gas) while PowerGen keeps Fiddlers Ferry (2 GW, coal) and Ferrybridge (2 GW, coal). In this scenario, prices are much higher in the early years of this century. If wholesale prices had stayed at this level, we do not believe that TXU Europe would have got into financial difficulty. Accordingly, we do not break up TXU during 2002. This assumption actually slightly reduces concentration at the end of our period, since nearly half of TXU's capacity was acquired by PowerGen. Adding capacity to PowerGen has a bigger impact on the HHI than breaking up TXU (since PowerGen is a much larger firm in this counter-factual).

Our third counter-factual relates to the increase in capacity, relative to the level of demand, which coincided with the start of NETA. To create a scenario in which capacity did not increase, we remove four CCGT stations commissioned during 2001 from our dataset. The stations involved are Shoreham (0.4 GW, March 2001), Shotton (0.2 GW, March 2001), Great Yarmouth (0.4 GW, May 2001) and Coryton (0.9 GW, March 2001). Their combined capacity of 1.9 GW is about 3% of the industry's total. A fourth counter-factual combines these assumptions, giving results with no divestitures, and less capacity from March 2001 onwards.

Our last counter-factual notes that fuel input prices rose during 2000, potentially offsetting the other factors that would have reduced prices. To assess the impact of this, we run a simulation using the month-by-month fuel input prices from 1999 in each of the remaining years of the sample.[10]

[10] In other words, we use the fuel prices for January 1999 in January 2000, January 2001, and so on.

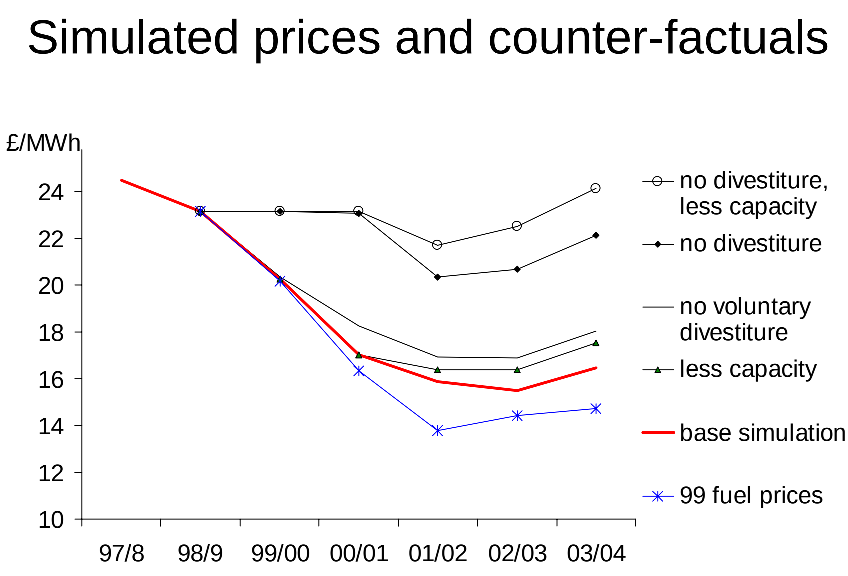

Figure 6

Figure 6 shows the results of these simulations, presented as annual average prices compared to the base simulation. It appears that prices would have been between £1/MWh and £2/MWh lower, compared to the base simulation, had fuel prices not risen after 1999. The additional capacity added during 2001, appears to have reduced prices by about £1/MWh. This is slightly less than the apparent effect of the generators' voluntary divestitures – the simulation without these has prices that are between £1/MWh and £1.50/MWh higher than the base simulations. If there had been no divestitures at all, however, average prices would have remained almost unchanged over the last three years of the Pool. While the simulated prices fall in 2001/2, they then recover as demand increases relative to capacity. Without any divestitures, prices would have been roughly one-third higher from 2001/2 onwards. The highest prices come from the scenario with no divestitures and no capacity commissioned during 2001, and are nearly 50% above the base simulations.

Fuel prices, the amount of capacity, and the level of concentration in the industry all clearly affect market prices. Given the size of the changes considered here, however, it is clear that the divestitures had the greatest impact upon prices. Furthermore, the first 4 GW of compulsory divestitures (from each company) had a much bigger impact than the 3GW or so of sales that each company then made voluntarily. This non-linear relationship between concentration and prices justifies the use of a modelling approach in preference to the search for a reduced-form relationship between, say, the Herfindahl index and the level of prices.

8. CONCLUSION

Electricity prices in England and Wales, which had been significantly above marginal costs, fell sharply in the last years of the centralised electricity market, the Pool. The decentralised New Electricity Trading Arrangements introduced in March 2001 saw much lower prices, and the change in trading rules has been viewed (particularly by the industry's regulator) as one of the main reasons for the price reduction.

In this paper, we use a supply function model to simulate the course of energy prices between April 1997 and March 2004. This is based upon the industry's actual marginal costs, but we divide the capacity owned by the larger, "strategic", firms into $\hat{n}$ symmetric firms, where $\hat{n}$ is the inverse of the Herfindahl index (calculated for those firms). This avoids the difficulties of calculating non-linear supply functions for asymmetric firms, and we suggest that this method of simulation might be more widely applied.

We find that our base simulation tracks the course of prices over this period quite closely, and that there is little evidence of a structural break in the relationship between our simulation and the actual monthly average prices. If the introduction of NETA had made the market more competitive in the sense of changing the relationship between market concentration and prices, then we should have found that simulations that performed well for the Pool would have broken down after March 2001. Either the underlying relationship between market concentration and prices was not affected by the change in trading arrangements, or there was some weakness in the model, of a very specific type. Despite performing well for the first four years of our period, it would have to break down in the face of conditions like those from early 2001 onwards, so that it would have under-predicted prices, relative to those that the Pool would have produced, had it continued to operate. This under-prediction would have to be roughly equal to the amount by which the change in market rules actually did reduce prices. In the absence of any particular reason for the model to have broken down (2001/2 was not very different from 2000/1), and given the many papers arguing that NETA should not have fundamentally changed the relationship between market concentration and market prices, we believe that this alternative explanation is implausible. Our results should be taken as evidence that NETA did not have a direct impact upon market prices for electrical energy.

NETA did have a direct impact on the market price for electrical capacity, because the Pool's Capacity Payment was abolished with the Pool. Since Capacity Payments had reached high levels in the late 1990s, despite an apparent surplus of capacity, their abolition contributed directly to the reduction in overall electricity prices. It should have been possible, however, to abolish Capacity Payments while keeping the rest of the Pool at a fraction of the cost of introducing NETA.

Our counter-factual simulations suggest that the lower prices were the result of additional capacity, and of divestitures, forced and voluntary, by the major generators. Both generators wanted to become vertically integrated, and the forced divestitures were the price for regulatory approval. To the extent that NETA encouraged the trend towards vertical integration, it therefore had an indirect impact on prices – although we note that vertical integration has its own competition concerns. What this paper has shown, however, is that the change from a centralised, compulsory, spot market to a decentralised market based upon bilateral trading does not appear to have changed the relationship between concentration and short-term market prices.

9. APPENDIX

We have introduced a methodology for calculating non-linear supply functions for an industry made up of asymmetric firms, modelling them as if the industry consisted of $\hat{n}$ symmetric firms, where $\hat{n}$ is the inverse of the Herfindahl index. In the case of linear marginal costs and demand, it is possible to compare this approximation with the actual linear supply function equilibrium. We have done so, using the capacity shares (among the strategic firms) of our strategic generators in September of each year between 1997 and 2003. We have taken an industry marginal cost function of

$$C' = 10 + 0.0005Q \qquad (6)$$

where Q is the industry output in MW, and C' is marginal cost in £/MWh. This gives a minimum marginal cost of £10/MWh, and a marginal cost of £25/MWh at an output of 30 GW, consistent with the industry's costs in 2000. The demand slope is -100 MW per £/MWh, as in our simulations. The capacity shares we used are:

	Sep-97	Sep-98	Sep-99	Sep-00	Sep-01	Sep-02	Sep-03
NP	0.377	0.388	0.374	0.215	0.227	0.238	0.257
PG	0.357	0.330	0.246	0.260	0.189	0.198	0.209
Eastern	0.157	0.163	0.164	0.174	0.146	0.064	
AES	0.003	0.009	0.009	0.111	0.120	0.116	0.004
Edison	0.049	0.050	0.147	0.156	0.155	0.056	0.060
EdF	0.057	0.059	0.060	0.084	0.135	0.195	0.210
BE coal					0.027	0.028	0.030
AEP						0.106	0.115
Drax							0.114

Setting each firm's marginal cost slope to the industry's slope, divided by that firm's share of the industry's capacity, we obtained the following supply function slopes (in MW per £/MWh):

	Sep-97	Sep-98	Sep-99	Sep-00	Sep-01	Sep-02	Sep-03
NP	422	432	441	326	342	354	370
PG	411	399	346	372	299	310	320
Eastern	245	254	260	278	244	118	
AES	6	19	19	194	208	201	8
Edison	90	93	239	256	257	104	112
EdF	105	109	110	151	229	306	322
BE coal					52	54	58
AEP						187	199
Drax							198

We can compare the sum of these slopes to the industry supply function that would be obtained with our $\hat{n}$-firm approximation:

	Sep-97	Sep-98	Sep-99	Sep-00	Sep-01	Sep-02	Sep-03
HHI	0.300	0.292	0.253	0.188	0.166	0.166	0.185
$\hat{n}$	3.334	3.423	3.960	5.327	6.013	6.013	5.409
Industry supply function							
$\hat{n}$-firm approximation	1232	1258	1384	1571	1628	1628	1579
True equilibrium	1281	1305	1415	1577	1631	1634	1587

It can be seen that the $\hat{n}$-firm approximation gives a slightly flatter supply function than the true equilibrium, but that the difference becomes very small from September 2000 onwards. We can see how the two methods compare if we find the intersection of their supply functions with three demand curves, representing high, medium and low levels of residual demand for the strategic generators (that is, after implicitly deducting output from the competitive fringe). All the supply functions start from a price of £10/MWh, the intercept of the marginal cost function.

	Sep-97	Sep-98	Sep-99	Sep-00	Sep-01	Sep-02	Sep-03
Demand curve: 30,000 – 100 *p*							
$\hat{n}$-firm approximation	31.00	30.64	29.15	27.29	26.75	26.72	27.19
True equilibrium	31.77	31.36	29.54	27.35	26.78	26.78	27.27
Difference	0.025	0.023	0.014	0.002	0.001	0.002	0.003
Demand curve: 20,000 – 100 *p*							
$\hat{n}$-firm approximation	23.76	23.52	22.54	21.33	20.98	20.96	21.27
True equilibrium	24.26	23.99	22.80	21.37	20.99	20.99	21.32
Difference	0.021	0.020	0.011	0.002	0.001	0.002	0.002
Demand curve: 10,000 – 100 *p*							
$\hat{n}$-firm approximation	16.52	16.41	15.94	15.37	15.20	15.19	15.34
True equilibrium	16.76	16.63	16.06	15.38	15.21	15.21	15.36
Difference	0.014	0.014	0.008	0.001	0.001	0.001	0.002

It can be seen that the $\hat{n}$-firm approximation over-predicts prices by about 2% at first, falling to 1% by September 1999, and a negligible amount from September 2000 onwards. We believe that this is an acceptable margin of error, given that the asymmetric linear equilibrium will slightly under-predict prices in the presence of capacity constraints.

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