Market Power in the England and Wales Wholesale Electricity Market 1995-2000

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Abstract

This paper shows that generators exercised considerable market power in the England and Wales wholesale electricity market in the late 1990s. This is surprising because static oligopoly models predict that falling market concentration should have reduced market power. The paper tests the equilibrium assumption of these models that each generator's bids should maximize its short-run profits given the bids of other generators. It finds that the two largest generators could have profitably increased their output from the beginning of 1997. Their behavior was consistent with tacit collusion.

Key words: electricity markets, market power, static oligopoly models, tacit collusion, hedging contracts

JEL classification: C72, D43, L13, L51, L94

This paper examines market power and generator behavior in the England and Wales (E&W) wholesale electricity market, known as the Pool, in the second half of the 1990s. I show that generators exercised considerable market power in the late 1990s despite falling market concentration. This is surprising because static oligopoly models, which have been widely used to model wholesale electricity markets, predict that falling market concentration should reduce the incentives and ability of generators to raise prices above competitive levels. I further examine the applicability of these models by testing their Nash equilibrium assumption that each generator's bids should maximize its short-run profits given the bids of other generators. Consistent with the market power results, I find significant deviations from static profit-maximizing behavior for the two largest generators, National Power (NP) and PowerGen (PG), from the beginning of 1997 as they could have increased their short-run profits by submitting lower bids and increasing their output. Their behavior was consistent with tacit collusion, but it could also be explained by an attempt to raise the prices they could negotiate in future hedging contracts by increasing current Pool prices.

Figure 1 illustrates the motivation for the paper by showing what happened to wholesale electricity prices, market concentration and the prices of two major fuels used in generation during the lifetime of the Pool. Concentration and fuel prices, which are the largest component of generators' marginal costs, fell significantly but average electricity prices changed relatively little. This paper focuses on the second half of the 1990s when the fall in concentration and fuel prices was particularly dramatic.

The paper has two main parts. Section 2 measures the degree of market power being exercised in the Pool from 1995 to 2000 by comparing realized Pool prices with estimates of competitive benchmark prices. I find that, consistent with the suggestive pattern in Figure 1, generators exercised considerable market power from the beginning of 1997. The degree of market power which I find is comparable to that identified by Borenstein, Bushnell and Wolak (2002) at the height of California's electricity crisis and it is at least as great as that found by Wolfram (1999) in the early years of the Pool despite the fall in concentration. Generators exercised less market power in 1995 and 1996, when NP and PG had agreed to keep average Pool prices below certain levels set by the regulator.

Section 3 uses data on generators' bids and costs to test whether the bids of NP and PG satisfied the standard equilibrium assumption of static oligopoly models that each generator's bids should be profit-maximizing best responses to the bids of other generators. A complication is that generators signed unobserved quantities of financial contracts which hedged their exposure to Pool prices. These contracts should have weakened a generator's incentive to raise Pool prices. I find that both NP and PG were deviating from static profit-maximizing behavior from the beginning of 1997 under a range of conservative assumptions about their contract cover. In particular, I find that NP and PG could have increased their short-run profits by submitting lower bids and increasing their output.

These results are interesting because static oligopoly models have been widely used to model wholesale electricity markets. Green and Newbery (1992) and von der Fehr and Harbord (1993) use static supply function equilibrium and multi-unit auction models respectively to predict the potential for market power in the E&W Pool. Green (1996) and Brunekreeft (2001) use these models to show how the divestiture of capacity in the E&W Pool, which I discuss in Section 1, should have reduced market power. The logic for this result is simple: smaller generators tend to face more elastic residual demand curves and own less inframarginal capacity which can benefit from a price increase, so they have both less incentive and ability to raise prices by restricting output. Borenstein and Bushnell (1999) use a Cournot model to analyse market power in the California electricity market under different market structures.

Several papers have provided empirical estimates of market power in electricity markets. Wolfram (1999) finds that generators exercised less market power in the E&W Pool from 1992 to 1994 than predicted by Green and Newbery. Puller (2005) shows that prices in California were quite similar to those predicted by a Cournot model. Borenstein, Bushnell and Wolak (2002) and Joskow and Kahn (2002) show that a combination of market power and rising costs contributed to California's electricity crisis in the summer of 2000. I use a method similar to Borenstein, Bushnell and Wolak's to measure market power in the E&W Pool. Mansur (2005) applies a similar method to the Pennsylvania, New Jersey and Maryland (PJM) market.

Wolak (2000) and Hortacsu and Puller (2005) test whether the bids of individual generators were profit-maximizing best responses to the bids of other generators. This is similar to my analysis in Section 3. Wolak shows that a large Australian generator's bids were approximately consistent with profit-maximization given its high level of contract cover. Hortacsu and Puller find deviations from profit-maximizing behavior by small generators in the Texas Balancing Market.

Several papers have examined the E&W Pool in the late 1990s. Macatangay (2002) identifies patterns in NP and PG's bids which he suggests were consistent with tacit collusion. Evans and Green (2003) and Fabra and Toro (2003) note that mark-ups in the Pool fell significantly in October and November 2000. This coincided with an announcement that the Pool would be replaced in March 2001, and Evans and Green tentatively suggest that this announcement may have caused tacit collusion to break down. Bower (2002) suggests that prices may have been high in the late 1990s because a government moratorium on approving new gas-fired capacity between 1998 and 2000 may have removed the incentive for incumbent generators to keep prices low to deter entry. Newbery (2003) suggests that NP and PG may have wanted to keep Pool prices high to raise the sale prices of plants that they were planning to divest.

The paper is structured as follows. Section 1 describes the Pool. Section 2 provides the estimates of market power and Section 3 the analysis of NP and PG's bidding behavior. Section 4 concludes.

1. The England and Wales Electricity Pool in the 1990s

The Pool operated as a multi-unit uniform price auction to price and schedule the generation of electricity (Electricity Pool, 1996a,b; 1999). Each day every generator submitted price bids for each of its generating units together with a schedule of unit availability in each of 48 half-hour periods. The price bids for each unit consisted of a start-up price, a no load price and up to three incremental prices for different levels of output. These bids were used by the System Operator (the National Grid Company, NGC) to construct a minimum-cost production schedule to meet its price-inelastic forecast of demand in each period.[2] This production schedule, which ignored transmission constraints, was used to determine the System Marginal Price (SMP) which reflected the bids of the most expensive scheduled unit. Units which declared themselves available also received capacity payments, which depended on the probability that demand would exceed available capacity, even if they were not scheduled to produce. The Pool Purchase Price (PPP) was the sum of the SMP and this capacity payment. Firms buying from the Pool paid the Pool Selling Price (PSP) which paid for generation, capacity payments and ancillary services such as reserve. All generation was scheduled through the Pool and dispatched by NGC but generators and firms buying from the Pool, of whom the largest were Regional Electricity Supply companies (RECs), signed financial contracts to hedge Pool prices.

When the Pool was vested in 1990 its market structure was highly concentrated. NP and PG owned 47% and 30% of generating capacity respectively and all of E&W's coal, oil and peaking open cycle gas turbine (OCGT) units (OFFER, 1998a, p. 42-5). Nuclear Electric, which was state-owned, operated E&W's nuclear stations (14% of capacity). NGC owned two highly flexible pumped storage stations (3%), which it sold to Edison First Hydro in 1995, and Electricité de France (EdF) and two Scottish generators supplied electricity over interconnectors with France and Scotland (5%). As coal units tended to be marginal, NP and PG set the SMP in 95% of half-hour periods in the first two years of the Pool.

Several changes led to the market structure becoming less concentrated during the 1990s. First, new Combined Cycle Gas Turbine (CCGT) units were commissioned and most of these units were owned by new entrants. There were no CCGT units in 1990, but they accounted for 20% (11.8 GW out of 60.2 GW) of total capacity in 1996 and 30% (19.5 GW out of 64.5 GW) in 2000. This 'dash for gas', which hurt the British coal industry, was politically controversial and there was a government moratorium on approving new CCGT projects between 1998 and 2000.

Second, NP and PG closed 20.9 GW of old and inefficient coal, oil and OCGT capacity. However, because CCGT units tended to run continuously (as 'baseload'), the remaining coal units still set the SMP in over 80% of half-hour periods in 2000.

Third, NP and PG divested coal plants after negotiations with the industry regulator (OFFER, renamed OFGEM in 1999). The concentrated market structure at vesting, which resulted from a failed plan to privatize E&W's nuclear plants bundled with conventional units, was recognized as being susceptible to market power. After OFFER had investigated several irregularities in Pool prices, the House of Commons Energy Select Committee recommended in 1992 that OFFER should take steps to reduce the dominance of NP and PG, and should consider referring them to the Monopolies and Mergers Commission (MMC) which could order structural changes (Competition Commission, 2001, chapter 8). In February 1994 NP and PG reached an agreement with OFFER to avoid an MMC reference. NP and PG agreed to divest 4 GW and 2 GW respectively of coal capacity and to bid in such a way that annual time-weighted and demand-weighted average PPPs would be below £24/MWh and £25.50/MWh respectively (in October 1993 prices) from April 1994 to March 1996. This agreement was known as the Pool Price Undertaking. There was no cap on daily Pool prices, but NP and PG clearly risked an MMC referral if average Pool prices were too high.[3] NP and PG met their divestiture requirements in June 1996 by leasing 6.0 GW of coal capacity to Eastern Group. One unusual feature of the lease was that the lesser was to earn £6 for each MWh its units generated. I investigate below how far this 'earn-out' arrangement, which raised Eastern's marginal costs, can explain the observed high level of market power and NP and PG's bidding behavior.

The 1996 divestiture did not end concerns about market power and the regulator negotiated further divestitures in 1998 when NP and PG sought to buy electricity supply companies. PG sold two 2 GW coal plants to Edison in July 1999 and NP sold the 3.9 GW Drax coal plant to AES in December 1999. NP and PG also agreed to end the earn-out arrangement with Eastern (now TXU). The earn-out with PG was terminated in March 2000 while the earn-out fee with NP was reduced to £1.50/MWh in the summer of 2000 and terminated in January 2001 when NP sold the plants outright.[4] NP also voluntarily sold 1.9 GW of coal capacity to British Energy (owner of E&W's more modern nuclear plants since 1996) and 0.7 GW of CCGT capacity to NRG in early 2000, while PG sold 2 GW of coal capacity to EdF in January 2001. Despite these changes in market structure, the regulator and the government decided to replace the Pool with new institutions which they hoped would be more competitive. The New Electricity Trading Arrangements (NETA) replaced the Pool in March 2001.

Table 1 details how market structure changed between January 1995 and September 2000, the period studied in this paper. The first part of the table shows the share of generating capacity owned by each firm in April each year. The second part of the table shows the proportion of half-hour periods in which each firm set the SMP in each calendar year. These measures of market structure are different because nuclear, CCGT and interconnector units typically operated as baseload, whereas coal units provided most of the variation in output and tended to set the SMP. The decline in concentration was quite dramatic by both measures and the logic of static oligopoly models predicts that the Pool should have become much more competitive in the late 1990s.

2. Market Power in the E&W Electricity Pool

This section estimates how much market power was exercised in the Pool. Section 2.1 describes the method in some detail and Section 2.2 presents the results and a number of robustness checks. The main finding is that generators were exercising considerable market power in the late 1990s. I also show that generators exercised market power by increasing their price bids rather than by declaring significant amounts of inframarginal capacity to be unavailable.

2.1. Method

I follow Wolfram (1999), Borenstein, Bushnell and Wolak (2002, BBW) and Joskow and Kahn (2002) by measuring market power by the difference between observed wholesale market prices and estimates of competitive benchmark prices. The benchmark price is defined as the expected marginal cost of the highest cost generating unit required to meet electricity demand.[5] A price-taking owner of this unit would be willing to increase its output at this price.

My method for estimating competitive benchmark prices is similar to BBW's, with some adjustments to reflect features of the Pool. The outline of the procedure, which I apply to every half-hour period, is as follows. The first step is the construction of an aggregate marginal cost function (equivalently, a competitive aggregate supply function) assuming that all units are available. This step uses information on unit capacities, thermal efficiencies, input fuel prices and variable non-fuel costs. The second step adjusts this aggregate marginal cost function to allow for the fact that some units may be unavailable for technical reasons (outages) even if generators act competitively. I use US data on outage rates to simulate unit availability and adjust the marginal cost function by setting the capacity of units simulated to be unavailable to zero. The third step identifies the highest cost unit required to meet demand using the availability-adjusted marginal cost function and the Pool's price inelastic forecast of demand. The expected marginal cost is calculated as the average cost of the highest cost unit across 25 simulations of unit availability.

I now describe the details of the procedure. Appendix A provides further information on the sources of the data.

Unit Fuel Types and Capacities

I have Pool data on the bids and availability of all generating units and demand side bidders for every day from January 1995 to September 2000. I define a unit's capacity as the maximum capacity which the unit ever declares available.[6] NGC (2000) lists the fuel types of each unit and when units were commissioned and decommissioned. While I allow for the possibility that generators did not behave competitively when declaring active units available, I assume that they did act competitively when commissioning and decommissioning units. This is plausible as most new capacity was owned by small firms and an independent assessor examined NP and PG's plant closure decisions to make sure that they satisfied "the necessary economic criterion of whether prospective costs outweigh prospective revenues" (OFFER, 1998b, p. 9). In any event, if competitive generators would have delayed plant closures then my approach should bias my estimates of market power downwards.

Unit Marginal Costs

I calculate the marginal operating costs of fossil-fuelled units using estimates of fuel input costs, unit thermal efficiencies and estimates of plant operating and maintenance costs. I follow BBW in not including unit start-up costs in these estimates, but I provide some evidence below that these costs do not explain my results. Appendix A lists the fuel price series used. I measure the coal price using the price of imported coal because generators are likely to have used imported coal on the margin even though they also purchased substantial amounts of expensive British coal. I use the same thermal efficiency estimates for coal and oil units as Green and Newbery (1992).[7] I estimate the efficiency of CCGT units commissioned in a particular year using industry estimates reported in MMC (1996a), chapter 5 and Competition Commission (2001), chapter 7. These efficiencies increase from 47% for units commissioned in 1991 to 58% in 2000. I assume that OCGT units had thermal efficiencies of 20%, within Green and Newbery's 18% to 25% range. I take estimates of non-fuel operating costs for different plant types from MMC (1996a), p. 101 and assume that they increased with UK manufacturing wage inflation.

E&W had four types of non-fossil unit: nuclear, pumped storage, the interconnectors with France and Scotland and demand-side bidders. Nuclear units had lower variable costs than other types of unit (MMC, 1996a, p. 101) so I assume that they were at the bottom of the aggregate marginal cost function. As demand always exceeded the total capacity of nuclear units, this removes the need to explicitly estimate their marginal costs. Pumped storage units used electricity to pump water up to a reservoir during off-peak hours so that it could be used to generate electricity when demand was high. I assume efficiencies of 60% for these units and use the average realized Pool Selling Price between the hours of 11 pm and 5 am the following day as their fuel price. These units only account for 1% of total generation so more detailed modeling of their supply decisions would be unlikely to affect the results. The marginal costs of EdF and the Scottish generators who supplied over the interconnectors would have reflected demand and supply conditions in France and Scotland. As they accounted for a small proportion of total capacity (Table 1) I assume that they bid competitively and use their incremental energy price bids to estimate their marginal costs. I make the same assumption for demand-side bidders, whose combined capacity made up less than 2% of total demand.

Unit Availability

Generators could potentially exercise market power either by increasing their price bids or by declaring inframarginal capacity unavailable so that units with higher marginal costs set the market price. I follow BBW in simulating unit availability using North American Electric Reliability Council (NERC) data on forced outage rates to define the probability that a unit would not be available if generators made competitive availability decisions.[8] Each unit is treated independently and if a unit is simulated to be available I assume that it is available at full capacity. Coal, oil and OCGT units are matched by capacity and year to the NERC data, while CCGT and pumped storage units are matched by year only as the NERC data does not list outage rates by capacity for these units.

Nuclear units are matched by year to the average for nuclear units in the NERC data, as the particular types of nuclear unit used in E&W are not listed by NERC.

I make three exceptions to using NERC forced outage rates to simulate unit availability. First, I assume that two pumped storage units were not available to meet demand, reflecting NGC's practice of keeping two of these units in reserve for frequency control purposes (NGC, 2000, p. 6.5). Second, recently commissioned units had unusual availability patterns because of testing requirements (Green, 2004) rather than because their owners were exercising market power, so I use a unit's actual availability for the first six months after commissioning. Third, I cannot use NERC data to simulate the availability of the interconnectors or demand-side bidders. Consistent with my assumption that these units made competitive price bids I also assume that they made competitive availability decisions and so use their actual availability.

Aggregate Demand and Maximum Prices

I measure demand using the Pool's day-ahead forecast of Total Gross System Demand (TGSD) which the Pool used to set the SMP. TGSD included generation required to make up for transmission losses and the expected demand of pumped storage units during off-peak periods (Electricity Pool, 1996a, p. 16-27). The intersection of this price-inelastic demand forecast and the adjusted aggregate marginal cost function identify the highest marginal cost unit required to meet demand.

Although demand never exceeded available capacity during the lifetime of the Pool, this can happen when I simulate available capacity. In this case I use the Pool's estimate of consumers' maximum willingness to pay for supply (the 'Value of Lost Load', VOLL), equal to £2,000/MWh in 1990 prices, in place of the marginal cost estimate (Electricity Pool, 1996a, p. 111).

Measure of Market Power

I calculate the competitive benchmark price in a half-hour period as the average of the estimated marginal cost across 25 simulations of unit availability. Following BBW, I calculate an index of market power, *MP(ℓ)*, defined as

$$MP(\ell) = \frac{\sum_{t\in\ell} \Delta TC_t}{\sum_{t\in\ell} TC_t} = \frac{\sum_{t\in\ell} (SMP_t - \overline{P}_t)Q_t}{\sum_{t\in\ell} SMP_t Q_t}$$

where ℓ is a set of half-hour periods and $SMP_t, \overline{P}_t$ and Q_t are the realized SMP, estimated competitive benchmark price and forecast demand respectively in half-hour period t. TC_t is the total wholesale procurement cost of electricity and $MP(\ell)$ measures the proportional increase in procurement costs due to realized prices being above competitive benchmark prices. The SMP, which did not include capacity payments, is the appropriate measure of the electricity price as my estimates of competitive benchmark prices reflect only the marginal costs of generation and not the costs of making capacity available. The SMP was also set without taking into account transmission constraints and I ignore these constraints when estimating competitive benchmark prices.

2.2. Results

Table 2 presents summary statistics on demand, prices and the marginal costs of fossil fuel plants. The marginal cost estimates are consistent with those in industry reports. For example, MMC (1996a), p. 99-101 reports that CCGT marginal costs in 1995 were between £11/MWh and £16/MWh while my estimates for the same year are between £12.49/MWh and £14.98/MWh. Competition Commission (2001), p. 130, reports that coal units had marginal costs between £11/MWh and £14/MWh in 1999/2000 while my estimates are between £10.24/MWh and £13.58/MWh.

Table 3 presents the results for each quarter during the sample period. The third and fourth columns list average demand and prices and the next three columns list the estimates of the average competitive benchmark price, $\sum_{t \in \ell} \Delta TC_t$ and $MP(\ell)$ for the 'base case' assumptions described above. The remaining columns present estimates of $MP(\ell)$ under some alternative assumptions.

Base Case Results

The market power index in 1995 and 1996 varies between 0.23 and 0.36, with the realized procurement cost of electricity exceeding the cost based on competitive benchmark prices by, on average, almost £100,000 per half-hour period and the average SMP exceeding the average competitive benchmark price by between £3 and £8/MWh. Of course, generators' profits would also depend on their fixed costs. The market power index increases in the first quarter of 1997 and varies between 0.30 and 0.63 for the rest of the sample period. It also displays a more seasonal pattern, taking higher values in the first and fourth quarters when demand in E&W was high, although the seasonal pattern is weaker in the final year of the data. Applying BBW's method for calculating standard errors, the estimated $\sum_{t \in \ell} \Delta TC_t$ is significantly different from zero at the 1% level in all quarters except the first quarters of 1995 and 1996.

I find more market power from the beginning of 1997 because of lower competitive benchmark prices, reflecting falling fuel prices and the replacement of old coal and oil capacity with more efficient CCGT capacity, as well as higher average electricity prices especially in the first and fourth quarters. It is noticeable that competitive benchmark prices do not have a seasonal pattern. The reason for this can be seen in Figure 2 which shows aggregate marginal cost functions given expected unit availability for February and August 1997 together with realized demand and prices. Marginal cost is almost constant in the region covered by all realizations of demand so that, even though demand is higher in February, competitive benchmark prices in the two months are very similar. This pattern holds quite generally as generating capacity was always between 20% and 30% greater than peak demand during the lifetime of the Pool (OFGEM, 2000, p. 8).

NP and PG's Pool Price Undertaking, which committed them to keep average Pool prices below certain levels, provides a straightforward explanation for why generators exercised less market power in 1995 and 1996 than after 1997. However, comparisons with other markets and with the earlier history of the Pool show that the degree of market power being exercised after 1997 was really quite considerable despite the decline in market concentration. For example, BBW estimate that at the height of California's electricity crisis between June and August 2000 the market power index was between 0.50 and 0.63 compared with an average value of only 0.09 in 1999. Of course, in California market power was combined with a shortage of capacity and significant increases in fuel and pollution permit prices, so that there was a dramatic increase in electricity prices which attracted popular attention. Mansur (2005) finds average values of the market power index of 0.06 and 0.24 for the PJM market in the summers of 1998 and 1999 respectively.

I can also compare my estimates of market power with Wolfram's (1999) estimates from before the Pool Price Undertaking when the Pool's market structure was much more concentrated. For example, NP and PG owned over 75% of total capacity in March 1993 (MMC, 1996a, p. 90) compared with 47% in March 1999. Wolfram estimates, using data from a subset of months each year that the average half-hourly Lerner Index was 0.241 from January 1992 to March 1993 and 0.259 from April 1993 to March 1994. Her methodology is different to mine but I have repeated her analysis for my time period.[9] Using the same subset of months as Wolfram and dropping four half-hour periods where the price was less than £0.02/MWh, I estimate that the average Lerner Index was 0.127 from April 1996 to March 1997, 0.250 from April 1997 to March 1998, 0.363 from April 1998 to March 1999, 0.299 from April 1999 to March 2000 and 0.255 after March 2000. Therefore, despite the fact that NP and PG's combined market share had fallen by around almost 30 percentage points, more market power was being exercised in the Pool in 1998 and 1999 than in 1992 to 1994.

If unit marginal costs are systematically underestimated then market power will be overestimated. A supplementary appendix, available on the journal's website, shows that the qualitative results are not sensitive to using higher estimates of fuel or operating and maintenance costs. A different potential problem with my method of estimating competitive benchmark prices is that technical constraints, such as ramp rates, may prevent some low cost units from operating. In particular, it may not be possible (or efficient once start-up costs are taken into account) to run a coal or CCGT unit for only one or two half-hour periods to meet peaks in daily demand, so that units with higher marginal costs must operate instead. It would therefore be a concern if my estimates of market power only reflected differences between actual and competitive benchmark prices in peak demand periods.

Figure 3 shows monthly values of the market power index when I divide each day's 48 half-hour periods into three groups of 16 periods based on the level of demand. While the index tends to be higher in high demand periods, the index increases in the late 1990s for all levels of demand and the increases in the market power index are actually larger for medium and low demand periods. This suggests that technical constraints or start-up costs cannot explain my results.[10]

Eastern Earn-Out

As described in Section 1, when Eastern leased 6 GW of coal capacity from NP and PG, it agreed to pay the lesser £6 for each MWh the units generated. The 'base case' ignored the effect of this fee on Eastern's marginal costs and it is interesting to ask how much market power in the late 1990s can be attributed to this fee. Column (2) presents the market power index when I add the fee to Eastern's marginal costs. The market power index falls only slightly. This is because, based on NERC forced outage rates, the expected combined available capacity of nuclear, CCGT and coal units and the interconnectors, which make up the low-cost and flat parts of the aggregate marginal cost function, exceeded demand by more than the expected available capacity of Eastern's leased units in 73,169 out of 74,094 half-hour periods after the Eastern divestiture. Therefore, while assuming higher costs for Eastern's units typically moves these units 'out of merit', it has only a small effect on competitive benchmark prices.

Actual Unit Availability

The base case used NERC forced outage rates to simulate unit availability. Column (3) shows the estimates of the index when I use actual unit availability. As well as acting as a robustness check, this allows me to examine whether generators exercised market power by declaring inframarginal capacity unavailable so that units with higher marginal costs set the SMP. Wolak and Patrick (1997) suggest that generators might prefer to exercise market power in this way, rather than by increasing their price bids, if it is harder for a regulator to detect uncompetitive availability decisions. If so, using actual availability should reduce the market power index significantly.

The market power index falls in all but one quarter, but by an average of only 2.1 percentage points.[11] Even if generators made competitive availability decisions we would expect a small fall in the index because NERC forced outage rates do not include time that units are unavailable for scheduled maintenance. The results therefore suggest that generators exercised little market power by declaring inframarginal capacity unavailable.

As this conclusion is potentially controversial I have also performed an analysis of how much inframarginal capacity NP and PG declared unavailable. This is included in the supplementary appendix. It shows that, on average, the availability of NP and PG's inframarginal units was close to that predicted by NERC's Availability Factors, which allow for scheduled maintenance. In addition, NP and PG tended to declare more capacity unavailable in the low demand and low market power summer months, which is when competitive generators would schedule maintenance. The conclusion is also made more plausible by the fact that a license condition introduced in 1991 required NP and PG to provide the regulator with detailed plans for the availability of each unit and explain significant deviations from these plans. This condition was designed to prevent generators exercising market power through their availability and plant closure decisions (Competition Commission, 2001, p. 183) and it should have made it difficult for NP and PG to declare capacity unavailable opportunistically.

3. Testing Best Response Behavior

The finding that generators were exercising considerable market power in the late 1990s, in spite of falling market concentration, raises the question of whether this can be consistent with the type of static oligopoly model usually used to analyze electricity markets. In this section I assess the applicability of these models in a more detailed way by testing their Nash equilibrium assumption that each generator's bids should be short-run profit-maximizing 'best responses' to the bids of other generators. In particular, I use data on the bids of the two largest generators, NP and PG, and ask whether either of them could have unilaterally increased their short-run profits by submitting higher bids (reducing their output) or by submitting lower bids (increasing their output) holding the bids of other generators fixed. I find that, from the beginning of 1997, both generators could have increased their profits by lowering their bids and significantly increasing their output. The analysis requires simplifying assumptions, but I show that varying these assumptions does not change the qualitative results. Section 3.1 describes my method, Section 3.2 presents the results and robustness checks and Section 3.3 discusses the interpretation of my findings.

3.1. Method and Simplifications

As described in Section 1, the Pool operated in the following way. Every day generators submitted bids for each of their generating units. These bids had five price elements (start-up price, no load price and up to three incremental energy prices), which were fixed throughout the day, and a schedule of how much of the unit's capacity was available in each of 48 half-hour periods. A software program called GOAL used these bids and price-inelastic forecasts of demand to schedule production in each period with the aim of minimizing total daily costs. This 'unconstrained schedule' satisfied technical constraints on unit operation but not transmission constraints and was used to set the SMP.

I analyze whether a generator's bids were consistent with best response bidding by comparing estimates of its daily profits from its actual bids with estimates of the profits which it could have made from using a specific set of alternative bids holding the bids of other generators fixed. This procedure requires me to estimate unit output and prices in each half-hour period for different sets of bids. The comparison ignores the effects of capacity payments and transmission constraints on profits, but I discuss below whether these factors could explain the results.

A potential limitation of my analysis is that it examines whether a generator's bids maximized its profits given the realized level of forecast demand and the realized bids of other generators, whereas static oligopoly models assume that a generator maximizes its expected profits. The bias from examining realized profits should be small because generators faced relatively little uncertainty in practice. The demand forecast used to set prices was based on historic realizations of demand and weather forecasts, both of which were available to generators (Electricity Pool, 1996a, p. 16). Generators were also quite well informed about other generators' bids as these changed relatively little from day-to-day and a generator had access to all bids with a one day delay (Electricity Pool, 1999, p. 693).[12] Wolak (2000) and Hortacsu and Puller (2005) also look at whether generators maximize their realized rather than expected profits.

The calculation of profits requires me to estimate a generator's output for different bids. As I do not have access to GOAL, I have developed an alternative algorithm, described in Appendix B, to schedule unit output. This alternative algorithm is partly based on descriptions of GOAL in Electricity Pool (1999), Section 8. Given my estimated output schedule, the SMP is calculated using the Pool's formulae. My scheduling algorithm is computationally quite intensive so I focus on results for Wednesdays as a representative weekday. Generator costs are calculated using the unit marginal costs described in Section 2.

I compare a generator's profits from its actual bids with its profits from a set of alternative bids which decrease or increase all of its price bids for all of its available units by the same proportion. This approach is necessary as the size of a generator's strategy space, with 5 price bids and half-hourly availability for each unit, makes it infeasible to calculate optimal bids. Considering only a limited set of alternative bids should bias me towards finding that a generator's actual bids were profit-maximizing. Specifically I consider decreasing a generator's bids on a given day by 50%, 40%, 30%, 25%, 20%, 15%, 10% and 5% and increasing them by 5%, 10%, 15%, 20%, 25%, 30%, 40%, 50%, 100% and 200%, holding the bids of other generators fixed.[13] I take a generator's unit availability as given, consistent with the evidence of Section 2 that generators did not exercise market power by distorting their availability decisions. If I allowed generators to make additional units available then this would reduce their marginal costs from increasing output and so strengthen my conclusion that they could have profitably reduced their bids.

A generator's profits depended not only on its output, costs and Pool prices, but also on its financial contracts with electricity supply companies.[14] These 'contracts for differences' hedged Pool prices. If the Pool price was above the contract price then the generator paid the supply company the difference on the contract quantity. In two-way contracts, the supply company paid the difference if the Pool price was below the contract price. Ignoring the effects of capacity payments, transmission constraints, unit start-up costs and the Eastern earn-out, generator i's variable profits on a particular day can be expressed as

$$\pi_i = \sum_{t=1}^{48} \sum_{g \in G_i} [P_t^{POOL}(b_i, b_{-i}, \theta) - c_g] q_{gt}(b_i, b_{-i}, \theta) + [P_{it}^C - P_t^{POOL}(b_i, b_{-i}, \theta)] Q_{it}^C$$

where b_i are the bids of units belonging to i, θ is a vector of aggregate demand in each period, c_g is the marginal cost of unit g, q_{gt} is the output of generating unit g in half-hour period t and P_t^{POOL}, P_{it}^C and Q_{it}^C are the SMP, contract price and contract quantity. As described by Green (1999) and Wolak (2000), contracts weakened a generator's incentive to restrict its output by reducing the amount of inframarginal capacity which could profit from a price increase. This formulation also shows that while contract quantities affected a generator's profits from different bids, contract prices did not.

Generators' contract positions are confidential so I need to make an assumption about how much of their output was covered by contracts. A number of reports indicate that the vast majority (e.g., over 90%) of NP and PG's actual output was covered.[15] As my most interesting finding is that generators could have profitably lowered their bids in the late 1990s I make the deliberately conservative 'base case' assumption that 80% of their actual output was covered in each half-hour period. If more of their output was covered, lower bids would have been even more profitable.

3.2. Results

Performance of the Scheduling Algorithm

My results depend on being able to predict prices and quantities with reasonable accuracy. I evaluate the algorithm's performance using generators' actual bids for all days of the week, not just Wednesdays. Figure 4(a) shows actual and predicted weekly averages of the SMP from 1995 to 2001. The series track each other closely with a correlation coefficient of 0.93. The match is worst in 1995 when I underestimate the SMP by, on average, £1.92/MWh.

Figure 4(b) shows various percentiles of the difference between actual and predicted prices for each half-hour period of the schedule day (which ran from 5am to 5am) together with the average level of demand. The median error is close to zero in every period and prices are predicted accurately at the beginning and end of the schedule day and in the middle of the day. However, the SMP is frequently underestimated in periods around the morning and afternoon demand peaks. I show that my results are robust to excluding these periods.

I do not have half-hourly unit output data but the regulator provided me with annual output data for power stations, many of which contain several units. Figures 4(c) and (d) compare actual and predicted station output for financial years 1996/97 and 1999/00 (the match for the other years is similar). The match is good, although I tend to underestimate the output of pumped storage and oil-fired power stations. The flexibility of these units made them ideal for meeting unexpected fluctuations in demand.

Base Case Results and the Eastern Earn-Out

Table 4 presents the results for my 'base case' assumption that each generator had 80% of its estimated actual output covered by hedging contracts in each half-hour period. I start by discussing the results when I ignore the effect of the Eastern earn-out on NP and PG's profits. The table shows the generators' average half-hourly outputs in each quarter given their actual bids and columns (1) and (5) show their average outputs using the bids which I estimate would have maximized their profits. Output is measured in MW of active capacity. For example, I estimate that NP's actual average output in the first quarter of 1995 was 13,609 MW and that its profit-maximizing output would have been 12,320 MW. The table also indicates whether the difference between actual and profit-maximizing output in each generator-quarter was statistically significant.

The results show a similar pattern for both generators. Excepting the first quarter of 1995, actual and profit-maximizing outputs were quite similar up to the third quarter of 1996. The finding for the first quarter of 1995 reflects the fact that in February and March 1995 NP and PG submitted very low bids to try to meet the price cap agreed in their Pool Price Undertaking (see footnote 3).

From the fourth quarter of 1996, I estimate that both NP and PG would have maximized their short-run profits by increasing their output by an average of 1,434 MW for NP and 1,598 MW for PG, roughly equal to the capacity of three large 500 MW coal units. Higher output comes from submitting lower bids and I estimate that NP (PG) would have maximized its profits by reducing its bids on 202 (199) out of 208 days, with the average profit-maximizing change being a reduction of 30% (34%). I estimate that profit-maximizing bids would have increased NP (PG)'s profits by an average of £7,858 (£8,615) per half-hour period.

As described in Section 1, NP and PG received an earn-out fee when the units they leased to Eastern generated. This arrangement would have provided NP and PG with an incentive to increase their bids to avoid displacing their leased units if the margin on additional output was less than the fee. Columns (2) and (6) show profit-maximizing outputs when I include the effects of the earn-out in my calculations. There was no earn-out before June 1996 or for PG after March 2000 so these results are exactly the same as before. Profit-maximizing outputs tend to fall in the remaining generator-quarters, especially in those quarters where margins were relatively small (lower values of the market power index), but the overall pattern of the results does not change. From the last quarter of 1996, I estimate that NP (PG) would have maximized its profits by increasing its output by an average of 1,338 (1,550) MW, reducing the output of the units it leased to Eastern by an average of 300 (72) MW. NP (PG) would have maximized its profits by reducing its bids on 196 (197) out of 208 days. The estimated average increase in NP (PG)'s profits from using profit-maximizing bids falls to £6,879 (£8,373) per half-hour period. These results show that the earn-out cannot fully explain NP and PG's bidding behavior, although it may have reduced the competitiveness of the Pool.[16] I include the effects of the earn-out when calculating generator profits in all of the robustness checks described below. If I ignored the earn-out then I would find that larger increases in output were profitable.

Robustness Checks

Contract Cover: My base case assumption is that 80% of each generator's actual output was covered by contracts in every half-hour period. While this is a conservative assumption, one might be concerned if a slightly more conservative assumption significantly changed the results. Columns (3) and (7) present NP and PG's profit-maximizing outputs when I assume that 60% of their actual output was covered by contracts in each half-hour period. Lower contract cover causes profit-maximizing outputs to fall, but I continue to find that NP and PG would have maximized their profits by significantly increasing their output in all but two quarters from the beginning of 1997 for NP and all but four quarters for PG. As one would expect, the quarters in which I find less evidence that the generators could have profitably increased their output are those in which the market power index was relatively low. The supplementary appendix shows that the qualitative results are also unchanged if I assume that generators had a lower proportion of their output covered by contracts in peak demand periods.

Evans and Green (2005) find that monthly average observed Pool prices after April 1997 were similar to those predicted by a calibrated supply function equilibrium model where generators *without contracts* maximize their static profits. Columns (4) and (8) show the profit-maximizing outputs when I assume no contract cover. Consistent with Evans and

Green's finding, the differences between actual and profit-maximizing outputs are not statistically significant in most generator-quarters from April 1997 and PG's average output is within 17 MW of its average profit-maximizing output. The consistency of my results with those of Evans and Green's quite different approach suggests that the details of my method are not driving my results.

When I assume lower levels of contract cover, I find that NP and, to a lesser extent, PG could have profitably restricted their output in 1995 and 1996. This partly reflects the fact that before the divestiture of coal plants to Eastern in June 1996, the capacity of other generators was frequently insufficient to meet demand, giving NP and, less frequently, PG a price-inelastic residual demand curve and the ability to unilaterally set the Pool price at its maximum level of above £2,000/MWh.[17] Of course, if either generator had exercised this degree of market power it is almost certain that the government would have intervened.

Generator Costs: Higher marginal costs would make it less profitable for a generator to increase its output. I show that my results are robust to two different changes in costs. The first change uses average fuel prices paid by generators, as listed in Department of Trade and Industry's *Quarterly Energy Prices* publication, to measure input fuel prices. In particular, this increases the marginal costs of NP and PG's coal units because average prices reflect purchases of expensive British coal. Profit-maximizing outputs, listed in columns (1) and (5) of Table 5, fall slightly compared to those in the base case (columns (2) and (6) of Table 4) for most generator-quarters, but the qualitative results from the beginning of 1997 do not change.

The second change includes estimates of start-up costs from switching units on. A *Power UK* article in December 1994 estimated that it cost £5,000 to start-up a large coal or oil unit. It also noted that smaller coal units had lower start-up costs and that CCGT unit start-up costs were 'negligible'. Another *Power UK* article in October 1995 estimated that the start-up costs of the large coal units which NP was proposing to lease to Eastern were between £8,000 and £13,000.[18] In order to be conservative I assume that CCGT units had start-up costs of £2,500 and that all other fossil units had start-up costs of £13,000. I also assume that units operating in every period also incurred start-up costs even though they could also have been running the previous day.[19] The profit-maximizing outputs, listed in columns (2) and (6) of Table 5, are lower than in the base case, but there is only one generator-quarter (NP in the third quarter of 1997) where including start-up costs changes the qualitative result.

Scheduling Algorithm: My scheduling algorithm does a reasonable, but not perfect job, of predicting prices and output given generators' actual bids. I now describe several robustness checks which show that imperfections in my algorithm are not driving my results, maintaining my base case assumptions about contract cover and costs.

A simple robustness check involves comparing the profitability of different bids using only those half-hour periods of the day when my algorithm predicts prices most accurately. Specifically, I compare profits using only those half-hour periods where the 10^{th} percentile line in Figure 4(b) is above -£10/MWh. This excludes 20 half-hour periods around the late morning and late afternoon demand peaks. Columns (3) and (7) in Table 5 show the profit-maximizing outputs. As before, increases in output are estimated to be profitable from the beginning of 1997, except for PG in the third quarter of 1998 when prices in low demand periods were close to or below marginal costs (Figure 3).

If my algorithm inaccurately estimates generator profits, then it is more likely that I will find that a generator could have done better than using its actual bids when the set of alternative bids is large. I address this concern by considering only increasing or decreasing a generator's current bids by 25%. As reductions of more than 25% were often the most profitable changes in the base case from the beginning of 1997, profit-maximizing outputs, listed in columns (4) and (8) of Table 5, tend to increase. However, the qualitative pattern is unchanged.

As a more radical robustness check I have also estimated profit-maximizing bids using an alternative algorithm, similar to the ones used by Hortacsu and Puller (2005) and Wolak (2000, 2003b). In each half-hour period a residual demand function is created for each generator using the Pool's demand forecast and the no load and incremental energy bids of other generators. This residual demand function and the generator's marginal costs are used to calculate its profit-maximizing output (without the need to consider only a limited set of alternative bids). The full results and computational details are contained in the supplementary appendix. The main finding is that, even though this alternative algorithm tends to consistently underestimate Pool prices because it ignores technical constraints and start-up costs, significant increases in output would have been profitable for NP and PG in 26 of the 30 generator-quarters from the beginning of 1997.

Capacity/Availability Payments and Transmission Constraints: As noted above, my calculations ignore the effect of capacity payments and transmission constraints on generator profits. I now consider whether these factors could explain why I find that NP and PG could have profitably increased their outputs from the beginning of 1997.

Capacity payments were set at $(VOLL\text{-}SMP_t)*LOLP_t$ per MWh for capacity which generated electricity and at $(VOLL\text{-}max(SMP_t,BP_t))*LOLP_t$ per MWh of potential generation for available capacity which did not generate, where *VOLL* was the exogenous 'Value of Lost Load', *LOLP* was the estimated probability that demand would exceed available capacity and *BP* was an increasing function of the unit's bid price. Capacity payments therefore provided generators with an additional incentive to *lower* their bids (to reduce *BP* and possibly the SMP) and so the fact that I ignore them cannot explain my results. In any event, the effect of capacity payments on bidding incentives should have been very small on most days: the average value of *LOLP* on Wednesdays from the beginning of 1997 was only 0.0013, and it exceeded 0.1 in only three half-hour periods.

The effect of transmission constraints on bidding incentives is ambiguous. Units which generated only because of transmission constraints were paid their bid price, whereas units which were constrained-off were paid the difference between their bid price and the SMP. Therefore, a generator expecting transmission constraints had an incentive to increase the bids of units likely to be constrained-on and an incentive to reduce the bids of units likely to be constrained-off.

There are two reasons for believing that transmission constraints are unlikely to explain my results. First, transmission constraints were more severe in the summer (Competition Commission, 2001, p. 155) whereas I tend to find larger differences between actual and profit-maximizing outputs in the first and fourth quarters. Second, an incentive scheme introduced for NGC in 1994 meant that the total costs associated with transmission constraints, including payments to all generators, fell dramatically in the late 1990s, from £255 million in 1993/94 to £25 million in 1997/98, £21 million in 1998/99 and £15 million in 1999/00 (Competition Commission, 2001, p. 124). An annual cost of £20 million is equal to roughly £1,142 per half-hour period which is much smaller than the profits that I estimate each generator could have made by reducing its bids.

3.3. Discussion

The analysis has shown that from the beginning of 1997 NP and PG could have unilaterally increased their profits by submitting lower bids and increasing their output if most of their output was covered by financial hedging contracts. NP and PG's behavior was therefore inconsistent with the basic equilibrium assumption of static oligopoly models. This conclusion should not be surprising given the high degree of market power identified in Section 2. Indeed, if 100% of a generator's output was covered by contracts, which is not inconsistent with the available evidence, then increases in output would always have been profitable as long as the Pool price was above a generator's marginal cost.

While NP and PG's behavior provides a direct explanation for why margins were so high, the interesting question is why NP and PG would have been bidding in a way inconsistent with static profit-maximization. One possible answer is that they, and potentially other generators, were engaging in tacit collusion, raising Pool prices above the level which could be sustained in a static Nash equilibrium. The Pool had many features conducive to sustaining tacit collusion: the same generators bid in a frequently repeated auction, there was good information about demand, cost conditions and recent bidding behavior, aggregate demand was inelastic and generators had capacity constraints (Armstrong et al., 1994, p. 32).

If NP and PG were the only generators who were tacitly colluding then we would expect their actual output level to be no less than the level of output that would maximize their *joint* profits. I have therefore repeated the analysis to find the bids which would have maximized NP and PG's joint profits. The results are included in the supplementary appendix. Assuming 80% contract cover and including the effects of the earn-out, I find that NP and PG would have maximized their joint profits by significantly reducing their joint output (consistent with tacit collusion) in every quarter up to the fourth quarter of 1999. Output reductions are more profitable if I assume 60% contract cover.

However, tacit collusion is not the only reason why NP and PG may have believed that higher Pool prices would increase their future profits. For example, the regulator noted that many people in the industry believed that the generators increased Pool prices to raise the prices they could negotiate in future hedging contracts (OFFER, 1998c, p. 21-2).[20] Standard models of the contract market (e.g., Green, 1999) would suggest that contract prices should reflect firms' expectations about future Pool prices rather than historic Pool prices, so this story is only plausible if electricity supply companies had adaptive expectations about Pool prices. Newbery (2003) suggests, in a story which has a similar flavor, that NP and PG may have raised Pool prices in 1999 and 2000 in order to increase the sale prices of the plants they were divesting.[21]

Under either explanation, it may have been easier for generators to exercise market power in the late 1990s because, with falling marginal costs, this did not require average Pool prices to rise significantly above historic levels. If Pool prices had increased significantly then it is likely that there would have been much greater pressure for the regulator or the government to intervene by negotiating a limit on average prices similar to the Pool Price Undertaking, requiring more radical divestiture or reforming the wholesale market's institutions as was eventually done in 2001. In practice, reform of the Pool was slow and when the regulator attempted to persuade the Competition Commission in 2000 that generators' licenses should prohibit them from exercising "substantial market power" it lost partly because the Commission believed that falling concentration and prices must mean that the scope for generators to exercise market power was limited.[22]

4. Conclusion

This paper has shown that generators exercised considerable market power in the late 1990s despite falling market concentration. This is inconsistent with the type of static oligopoly model usually used to model electricity markets. I provide further evidence against these models by showing that two largest generators could have increased their short-run profits by reducing their bids. This result is inconsistent with the assumption of short-run profit maximization. The generators' behavior was consistent with either tacit collusion or an attempt to raise the prices that they could negotiate in future hedging contracts by increasing current Pool prices.

The results have at least two important implications. First, while static oligopoly models are undoubtedly useful tools in modeling electricity markets, many features of these markets make it plausible that generators use dynamic strategies. This may mean that factors such as falling market concentration or hedging contracts are less effective at restraining market power than static models would suggest.

Second, if tacit collusion does explain why generators exercised so much market power then this suggests that market institutions should be designed in ways which make tacit collusion more difficult to sustain. In particular, the Pool's highly centralized institutions with inelastic aggregate demand, daily bidding and readily available information on all generators' recent bids and demand conditions, were almost ideal for sustaining tacit collusion. In this regard it is interesting to note that significantly less market power appears to have been exercised under NETA, which introduced more decentralized arrangements where the majority of output is traded and scheduled using long-term contracts (Evans and Green, 2003, National Audit Office, 2003).

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Appendix A: Data

Pool Data

Data on Pool prices, aggregate quantities, unit bids and unit availability, covering the period from January 1, 1995 to September 30, 2000, was purchased from ESIS Ltd. The data lists a number of different prices for each half-hour period. I use the 'Day Ahead' SMP which was determined when GOAL used generators' bids to produce the unconstrained schedule. I use the 'Ex-Post' PPP and PSP as these prices were intended to reflect actual unit availabilities rather than the availabilities declared the previous day. I measure demand using the Total Gross System Demand (TGSD) forecast. The Pool price data also identifies the marginal unit in each half-hour period. The generator bid data contains the price elements of each unit's bid (start-up, no load, 3 incremental prices) and its day-ahead availability in each half-hour period (the Pool's XA variable). There are a small number of half-hour periods where data is missing, usually on days when the clocks changed. There are also four days in January 1997 where the price bid data contains different unit identification codes to the availability data and I drop these days from the analysis. The bid data identifies the owner of each unit and these were cross-checked with NGC (2000).

Input Fuel Prices

I use the following series for fuel prices.

Unit Type	Fuel	Series
Coal	Steam Coal	International Energy Agency (IEA) *Energy Prices and Taxes* database quarterly series for price in $ per tonne of steam coal imports into the UK.
CCGT	Natural Gas	Department of Trade and Industry *Quarterly Energy Prices*

		series for price in pence per kWh of natural gas at UK delivery points.
Oil	Heavy Fuel Oil	Datastream's weekly heavy fuel oil 3.5% sulphur CIF NW Europe in $ per tonne (OILHFOL) series. Hydrocarbon excise tax added at high sulphur fuel oil rates from IEA *Energy Prices and Taxes*.
OCGT	Gas Oil	Datastream's weekly gas oil CIF NW Europe in $ per tonne (OILGASO) series. Hydrocarbon excise tax added at light fuel oil rates from IEA *Energy Prices and Taxes*.

All fuel prices were converted to UK £s per MWh using conversion rates for different fuels and energy units from the IEA's website and exchange rates taken from Datastream. As a robustness check I also use the quarterly 'Average Prices of Fuels Purchased by Major Power Producers' series from Table 3.2.1 of the Department of Trade and Industry's *Quarterly Energy Prices* publication.

Appendix B: Scheduling Algorithm

The Pool used an algorithm called GOAL to produce an unconstrained production schedule given each unit's bids and unit technical constraints.[23] This schedule was used to set the SMP. This Appendix describes the algorithm which I use to schedule output as I do not have access to GOAL. For a given schedule I calculate prices in the same way as the Pool using the formulae listed in Electricity Pool (1999), Section 12. The SMP in a half-hour period was the 'Genset Price' of the highest-priced unit operating. The way in which Genset Prices were calculated varied between Table A periods (most periods) and Table B periods (temporary demand troughs). In a Table A period the Genset Price of a unit was

$$GP = \frac{start-up + no\ load\ \ price\ accumulated\ in\ \ production\ run}{accumulated\ \ output\ in\ Table\ \ A\ \ periods\ in\ \ production\ run} + incremental\ \ price$$

so a unit's Genset Price in a Table A period depended on all elements of its price bid and its output in other periods. In Table B periods the Genset Price was equal to the unit's incremental price.

My algorithm works as follows:

1. I make two adjustments to the availability of units in the Pool data. First, I make two available pumped storage units unavailable in every half-hour period, consistent with the System Operator's policy of keeping two of these units in reserve for frequency control (NGC (2000), p. 6.5). Second, I reduce the availability of units in the first 6 months following commissioning by 50% as otherwise I significantly overestimate their output;
2. I assume that both nuclear units which were available in every period and non-coal units with zero price bids produced at their available capacity in every period. If a nuclear unit was only available in some periods, which was rare, I assume it did not operate in any period;
3. I create a 'merit order' by ranking all increments of available capacity (a unit could bid up to three increments) by calculating an average per MWh price of output using unit no load and incremental prices. These average prices were called 'Table A prices' (Electricity Pool (1996a), p. 27). Figure 5 shows the bid function of a unit bidding three increments and the Table A prices correspond to the slopes of the dotted lines.[24] The unit's 'efficient level' of output (X) minimizes its Table A price;

4. I use this merit order to create an initial output schedule to meet forecast demand (TGSD) using the increments with the cheapest Table A bids in each half-hour period;
5. I then reschedule production to meet four plausible technical constraints on how units could operate: (i) a pumped storage unit cannot operate for more than 20 half-hour periods in a day (if it does, I switch it off in the periods with the lowest prices based on the initial schedule); (ii) a large coal or CCGT unit cannot operate for less than 4 periods in the day (if it does, I switch it off) and (iii) a large coal (as identified by NGC (2000)) or CCGT unit cannot be temporarily off during the day (if it is, I turn it on at its efficient output level when it is temporarily off); and, (iv) units are unable to change their output by more than a certain amount between periods. The amount varies by unit type: 400 MW for oil units, 300 MW for large coal, CCGT and interconnector units, 200 MW for other coal units and no constraints on other units. To satisfy these constraints I try increasing the unit's output in the period with lower output if this is consistent with its availability, and otherwise I reduce its output in the period with higher demand. If these changes lead to demand exceeding scheduled output then I schedule more output from the merit order and otherwise I reduce the output of all units for which the constraints are not binding by the same proportion. This rescheduling procedure is iterated until all of the constraints are satisfied.
6. This schedule and the Pool's pricing formulae are used to calculate the total procurement cost of electricity. I then consider a number of possible changes to the schedule and implement them if they reduce the procurement cost. Specifically, for the 20 periods with the highest prices I consider allowing the following changes to the

output of the unit with the highest Genset Price, making sure that the technical constraints described above are not violated: (i) increase the unit's output during its production run to its efficient level; (ii) keep the unit on, at its efficient level, when it is temporarily turned off; (iii) increase the unit's output in other periods to its output level in the period in question; (iv) if the unit switches on, turn it on one period earlier; (v) if the unit switches off, turn it off one period later; (vi) reduce the unit's production (to a lower increment or by turning it off) and rescheduling its production to other units. This process is iterated, and prices recalculated, until no more cost reducing changes are found.

This provides the final production schedule which is used to calculate Pool prices and generator revenues.

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[1] I am grateful to the MIT Center for Energy and Environmental Policy Research for financial support and to Paul Joskow, Richard Green, Catherine Wolfram, two anonymous referees and participants at the University of California Energy Institute POWER conference for helpful comments. Richard Green provided me with access to the data on plant efficiencies and outputs. All errors are my own.

[2] A small number of large customers ('demand-side bidders') submitted bids in the same way as generators to reduce their demand.

[3] The demand-weighted price cap was exceeded by 1% in 1994/95 but the regulator concluded that NP and PG had not breached their undertaking because, after unusual outages had increased capacity payments, the SMP fell by over 70% from January to March as NP and PG tried to meet the cap. The regulator noted, however, that the price fall illustrated the generators' market power (*Power UK*, 'Gencos avoid rap on cap', June 28, 1995).

[4] *Power UK*, 'Customers see large price falls', February 29, 2000 and 'TXU to buy station freeholds', January 26, 2001.

[5] As noted by BBW, p. 1378, this approach may attribute high prices to market power rather than other market inefficiencies such as the System Operator's dispatch algorithm. This is less likely to be a concern in the Pool as the dispatch algorithm was explicitly designed to minimize costs.

[6] These capacities either match or slightly exceed the registered capacities for active units listed in NGC (2000).

[7] Green and Newbery's efficiency estimates are very similar to those of Rainbow et al. (1993) and, for a subset of coal plants, the estimates in OFFER (1998b). The estimates are at the plant rather than the unit level but units in the same plant were typically commissioned at approximately the same time and so should have similar efficiencies. Fifoots Point, a small coal plant which opened in 2000, is given the same efficiency as Uskmouth as it was a refurbishment of the Uskmouth plant.

[8] I use NERC '1982-2001 Historical Availability Statistics' data available at http://www.nerc.com/~filez/gar.html. Following BBW, I use a unit's Forced Outage Factor as the probability that a unit would be unavailable if a generator took competitive availability decisions. This is

calculated as 1 – EAF/(1-SOF) where EAF is the unit's Equivalent Availability Factor and SOF is the unit's Scheduled Outage Factor. The Forced Outage Factor does not allow for scheduled maintenance. BBW use Forced Outage Factors on the basis that competitive generators should not schedule maintenance at times of peak demand when there is more scope for generators to exercise market power. The use of Forced Outage Factors may be less appealing here as I find evidence of market power in non-peak periods as well as peak periods. However, the estimates of market power are similar using NERC's Availability Factors, which allow for scheduled maintenance, or actual unit availability.

[9] The most significant changes are the use of British coal prices (taken from reports in *Coal UK* and *Power UK*) to measure the coal price, the estimation of competitive availability by adding one-half of a standard deviation to a unit's average availability each month and the assumption that the thermal efficiency of CCGT units was 45%. The coal and CCGT assumptions are more conservative for my period than Wolfram's as generators switched to using more imported coal over time and CCGT units became more efficient.

[10] I have also estimated the market power index using the algorithm described in Section 3, which does take account of unit start up costs and technical constraints, to identify the marginal unit. The market power index drops by between 3 and 6 percentage points in each quarter, leaving the qualitative results unchanged. The existence of technical constraints and start-up costs could also lead me to underestimate market power in daily demand troughs because they would increase the costs of reducing output. This provides a potential explanation for why I estimate that the market power index is negative in some low demand periods. However, most of the months with a negative low demand index occur during the Pool Price Undertaking when the relative tightness of the demand-weighted and time-weighted price-caps may have given generators with market power an incentive to reduce prices in low demand periods. Reducing low demand prices was an intended effect of the Undertaking (Competition Commission (2001), p. 186).

[11] I estimate that generators exercised *more* market power with actual availability in the fourth quarter of 1995. This is because there were a small number of periods in December 1995 when demand was high and strikes in France meant that the usual flow of electricity into E&W from France was reversed. When I simulate availability demand frequently exceeds available capacity in these periods so I use the Value of Lost Load, £2,458/MWh, to estimate the competitive benchmark price. In contrast, actual unit availability exceeded demand even though the reserve margin was small enough to lead to very high capacity payments.

[12] I report results for Wednesdays and 84% of units which were available on Wednesdays had exactly the same price bids as the previous day. Generators tended to change their bids on Mondays or Saturdays. Generators are also likely to have been well-informed about other generators' costs. Changes in generators' contract positions, another source of potential uncertainty, were infrequent with the major contract rounds taking place in April and October (Competition Commission (2001), p. 132).

[13] I have also computed results allowing the generator to decrease bids for some of its units and increase them for others. The results using these alternative bids are qualitatively very similar, but they test the hypothesis of whether generators' could have deviated by submitting higher or lower bids less directly.

[14] NP and PG also acted as electricity suppliers in their own right, and contracts which fixed their prices as suppliers would have had the same effect on bidding incentives as hedging contracts with other suppliers.

[15] MMC (1996a), p. 254 reports that NP had 98.73% and 94.46% of its output covered by hedging contracts in financial years 1994/95 and 1995/96 respectively. MMC (1996b), p. 264 reports that PG had 91.56% and 102.27% of its output covered in these years. OFFER (1998a), Tables 5 and 9 report that in NP and PG were both contracted for over 95% of their output in 1996/97. OFGEM (2000), p. 32 reported that "typically 90% or more of demand is covered by contracts". Competition Commission (2001), p. 137, reports that PG was 100% contracted between July and October 2000 and had over 90% of its output hedged by contracts for 2000/01. The lowest estimate of contract cover is 75% for PG in July 1999 but this was due to a delay in PG selling stations to Edison which had been due to be completed in May 1999 (OFGEM (1999a), p. 4). NP had contracts for 85% of its output at the time.

[16] The earn-out does appear to have affected Eastern's bidding behavior. For example, from June 1996 to March 2000 Eastern produced 76% of its coal unit output from the units leased from NP, which were more efficient than those leased from PG, but this fell to 29% after the PG earn-out was terminated and the NP earn-out remained.

[17] In 21,301 (9,522) out of 26,200 half-hour periods prior to the Eastern divestiture the combined available capacity of generators other than NP (PG) was insufficient to meet demand.

[18] *Power UK*, 'Are low merit coal plants profitable?', December 21, 1994 and *Power UK*, 'NP close to £1 billion station sale', October 26, 1995.

[19] If I assume that units running all day did not incur start-up costs then I actually find that it would have been even more profitable for NP and PG to increase their output on most days because, by running more units continuously, they could have reduced their start-up costs.

[20] The same report noted that "generators denied that they were positioning themselves for contract renegotiations. Whether their main motive was short term Pool revenue or longer term contract revenue is unclear, but significantly higher SMP during winter 1997/98 would have been conducive to achieving both outcomes."

[21] An April 2001 article in *Power UK* ('Edison Mission to Sell Coal Plant', April 18, 2001) suggested that high Pool prices in 1999 had led to Edison overpaying PG for plant.

[22] Competition Commission (2001), p. 3. The regulator argued that costs had fallen much more dramatically than prices (p. 128) and that divestiture might have to be taken down to the level of the individual unit to curtail market power (p. 156). Wolfram (1999) also suggests that Pool prices were implicitly capped by pressure from the regulator with Pool prices tending to fall when the regulator made an announcement.

[23] Electricity Pool (1999), Section 8, outlines how GOAL worked. It first solved a Lagrangian relaxation and dynamic programming problem which produced a schedule which satisfied technical constraints. It then tried to improve on the schedule (reducing costs) by considering a sequence of changes to the schedule such as keeping units on when they operated on-off-on.

[24] For OCGT and demand side bidders I also include their start-up costs in calculating their average incremental prices as these units typically operated for only one or two periods and so start-up costs could have a large effect on their Genset Prices.

Table 1: Market Structure of the England and Wales Wholesale Electricity Market 1995 - 2000

(a) Generator Ownership Shares of Generating Capacity

	April 95	April 96	April 97	April 98	April 99	April 00
National Power	36.10%	34.97%	27.75%	26.87%	24.32%	13.90%
Powergen	27.50%	27.47%	24.38%	23.01%	22.24%	15.95%
National Grid	3.46%	-	-	-	-	-
Nuclear Electric/BNFL Magnox	19.07%	6.66%	6.44%	6.58%	6.35%	6.34%
EdF (Interconnector)	3.30%	3.27%	3.16%	3.23%	3.12%	3.11%
Scottish (Interconnector)	1.99%	1.97%	1.91%	1.95%	1.88%	1.88%
Eastern/TXU	0.67%	0.67%	10.74%	10.96%	10.59%	10.57%
First Hydro/Edison	0.38%	3.81%	3.68%	3.76%	3.63%	9.86%
British Energy	-	12.24%	11.83%	12.08%	11.67%	14.78%
AES	-	-	-	0.23%	0.61%	6.83%
Other	7.53%	8.95%	10.12%	11.34%	15.57%	16.78%
Herfindahl-Hirschman Index	0.2464	0.2217	0.1705	0.1608	0.1426	0.1000

(b) Generator Ownership Shares of SMP-Setting Unit

	Jan-Dec 95	Jan-Dec 96	Jan-Dec 97	Jan-Dec 98	Jan-Dec 99	Jan-Sept 00
National Power	53.03%	44.92%	34.92%	35.40%	31.00%	13.81%
Powergen	28.69%	31.85%	30.49%	32.26%	22.83%	16.21%
National Grid	11.67%	-	-	-	-	-
Nuclear Electric/BNFL Magnox	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
EdF (Interconnector)	2.28%	0.70%	2.37%	2.58%	10.89%	10.63%
Scottish (Interconnector)	1.74%	1.71%	1.15%	0.25%	0.02%	0.20%
Eastern/TXU	0.10%	7.60%	19.85%	18.64%	24.41%	11.57%
First Hydro/Edison	-	13.12%	10.91%	9.81%	7.47%	20.99%
British Energy	-	0.00%	0.00%	0.00%	0.00%	4.95%
AES	-	-	0.00%	0.29%	2.21%	19.50%
Other	2.39%	0.07%	0.30%	0.78%	1.18%	2.14%
Herfindahl-Hirschman Index	0.3783	0.3266	0.2670	0.2744	0.2257	0.1548

Notes

AES, Eastern, EdF and Edison also owned minority stakes in some independent power producers. The shares of these producers are included in the Other category. Demand side bidders are not included in the capacity measures and are included in Other for shares of the SMP-setting unit. Scottish includes both Scottish Power and Scottish and Southern Energy. First Hydro purchased National Grid's pumped storage stations in 1995. Unit capacity is measured as described in Section 2. Pool data from ESIS Ltd. identifies the unit setting the SMP in each half-hour period.

Table 2: Summary Statistics

	Units	Number of Observations		Mean	Std. Deviation	Min	Max
Pool Prices and Demand							
System Marginal Price (SMP)	£/MWh	100,490	half-hours	21.12	13.29	0	836.16
Pool Purchase Price (PPP)	£/MWh	100,490	half-hours	24.26	26.9	0	1108.12
Demand (TGSD)	MW of required capacity	100,490	half-hours	32,987	5,965	19,026	51,065
Marginal Costs							
CCGT	£/MWh	2,627,808	unit half-hours	12.40	1.28	9.54	15.12
Coal	£/MWh	6,260,976	unit half-hours	12.69	1.09	10.23	15.84
OCGT	£/MWh	4,160,448	unit half-hours	57.69	12.43	37.24	105.82
Oil	£/MWh	639,508	unit half-hours	20.65	3.46	13.95	33.07
Pumped Storage	£/MWh	1,007,500	unit half-hours	25.13	11.42	4.12	172.98

Notes:
Excludes periods with missing SMP or TGSD data and 4 days where unit codes in availability and bid data do not match. Costs of interconnectors and demand-side bidders are estimated from their bids. Nuclear units are assumed to have lower marginal costs than other types of unit.

Table 3: Estimates of Market Power

Quarter	Number of Half Hour Periods	Average Demand (MW)	Average SMP (£/MWh)	Average Competitive Benchmark (£/MWh)	Sum of ΔTC (£ million)	Estimates of Market Power Index (1) Base Case	(2) Eastern Earn-Out	(3) Actual Availability
Q1 1995	4,318	35,905	16.94	13.59	310	0.23	0.23	0.17
Q2 1995	4,368	29,267	18.77	13.03	425	0.34	0.34	0.32
Q3 1995	4,416	28,349	16.71	12.89	301	0.27	0.27	0.24
Q4 1995	4,416	34,192	22.40	14.95	655	0.36	0.36	0.42
Q1 1996	4,366	37,809	19.70	14.85	464	0.27	0.27	0.22
Q2 1996	4,368	30,319	19.90	13.64	486	0.35	0.35	0.33
Q3 1996	4,416	28,779	16.74	12.88	301	0.27	0.26	0.24
Q4 1996	4,416	35,188	19.60	13.30	558	0.35	0.32	0.33
Q1 1997	4,126	36,721	25.65	13.24	1,030	0.50	0.48	0.47
Q2 1997	4,368	30,318	21.00	12.49	631	0.43	0.43	0.42
Q3 1997	4,416	29,548	17.83	13.01	371	0.30	0.30	0.29
Q4 1997	4,416	35,264	28.67	13.42	1,330	0.56	0.55	0.55
Q1 1998	4,318	36,529	30.48	13.10	1,480	0.59	0.57	0.55
Q2 1998	4,368	31,050	21.13	12.15	683	0.45	0.44	0.43
Q3 1998	4,416	29,885	17.31	12.09	406	0.34	0.33	0.32
Q4 1998	4,416	35,810	25.53	12.17	1,190	0.55	0.53	0.54
Q1 1999	4,318	37,275	30.56	11.85	1,640	0.63	0.62	0.60
Q2 1999	4,368	30,923	16.48	11.65	367	0.32	0.31	0.29
Q3 1999	4,416	30,119	21.73	10.86	800	0.52	0.52	0.51
Q4 1999	4,416	35,869	20.86	10.88	868	0.50	0.49	0.49
Q1 2000	4,366	37,485	21.34	11.18	917	0.50	0.49	0.44
Q2 2000	4,272	31,929	18.15	11.38	523	0.40	0.40	0.38
Q3 2000	4,406	30,581	18.56	11.76	521	0.40	0.39	0.37

Notes
Excludes periods with missing SMP or TGSD data and 4 days where unit codes in availability and bid data do not match.

Table 4: Testing Best Response Bidding Behavior for NP and PG

		National Power					PowerGen				
			Estimated Profit-Maximizing Average Outputs					Estimated Profit-Maximizing Average Outputs			
			(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)
		Contract Cover	80%	80%	60%	0%	Contract Cover	80%	80%	60%	0%
		Eastern-Earn Out	No	Yes	Yes	Yes	Eastern-Earn Out	No	Yes	Yes	Yes
Quarter	Market Power Index	Estimated Actual Output					Estimated Actual Output				
Q1 1995	0.23	13,609	12,320 ***	12,320 ***	11,450 ***	11,450 ***	11,303	10,113 *	10,113 *	9,625 **	8,885 ***
Q2 1995	0.34	10,380	10,237	10,237	7,864 ***	7,212 ***	7,496	7,590	7,590	6,556 ***	5,431 ***
Q3 1995	0.27	8,930	9,099	9,099	7,038 ***	5,619 ***	6,559	6,585	6,585	5,139 ***	4,609 ***
Q4 1995	0.36	11,445	11,740	11,740	9,960 ***	8,424 ***	8,745	9,546 **	9,546 **	8,650	6,820 ***
Q1 1996	0.27	13,145	12,777	12,777	11,104 ***	10,377 ***	10,114	10,004	10,004	9,130 *	7,554 ***
Q2 1996	0.35	8,942	8,709	8,709	7,347 ***	6,737 ***	7,446	7,777 *	7,777 *	7,207	5,109 ***
Q3 1996	0.27	7,404	6,508 ***	6,444 ***	5,778 ***	4,816 ***	6,851	6,319 *	6,319 *	5,689 ***	4,852 ***
Q4 1996	0.35	7,802	8,801 **	8,653 **	8,128	5,419 ***	8,052	9,278 ***	9,058 ***	8,414	5,926 ***
Q1 1997	0.50	8,340	9,865 ***	9,762 ***	9,438 ***	7,040 **	7,728	9,839 ***	9,839 ***	9,512 ***	7,685
Q2 1997	0.43	5,987	7,949 ***	7,867 ***	7,402 ***	5,638	5,633	7,472 ***	7,397 ***	7,368 ***	6,041
Q3 1997	0.30	6,636	7,848 ***	7,848 ***	6,454	4,113 ***	5,985	6,689 ***	6,689 ***	6,339	3,999 ***
Q4 1997	0.56	6,997	9,375 ***	9,386 ***	8,827 ***	6,058	6,785	8,940 ***	8,940 ***	8,697 ***	6,692
Q1 1998	0.59	8,040	10,162 ***	10,162 ***	9,834 ***	7,460	7,076	9,953 ***	9,953 ***	9,777 ***	8,791 ***
Q2 1998	0.45	7,565	9,320 ***	9,320 ***	8,874 ***	4,911 ***	5,965	7,489 ***	7,489 ***	7,011 ***	5,360
Q3 1998	0.34	7,352	8,147 ***	8,003 ***	7,637 ***	5,858 **	5,827	6,736 ***	6,736 ***	5,959	4,697 ***
Q4 1998	0.55	7,189	8,607 ***	8,501 ***	8,254 ***	7,702	6,176	7,587 ***	7,587 ***	7,555 ***	6,058
Q1 1999	0.63	6,951	8,341 ***	8,197 ***	7,761 ***	6,289	6,117	7,395 ***	7,395 ***	7,003 ***	6,448
Q2 1999	0.32	5,389	7,020 ***	6,632 ***	5,234	4,342 *	5,614	7,217 ***	6,815 ***	5,761	4,449 **
Q3 1999	0.52	5,487	6,656 ***	6,584 ***	6,302 ***	3,991 ***	4,288	5,794 ***	5,765 ***	5,644 ***	4,794
Q4 1999	0.50	6,259	8,581 ***	8,272 ***	7,948 ***	5,881	5,009	6,766 ***	6,722 ***	6,688 ***	6,467 ***
Q1 2000	0.50	5,128	6,552 ***	6,542 ***	6,142 ***	4,700	4,962	6,795 ***	6,795 ***	6,621 ***	5,287
Q2 2000	0.40	4,154	4,596 ***	4,584 ***	4,487 ***	4,156	4,074	5,888 ***	5,888 ***	5,451 ***	4,668 *
Q3 2000	0.40	3,210	3,557 ***	3,542 **	3,542 **	2,790 *	2,960	4,109 ***	4,109 ***	3,753	3,224

Notes: Outputs measured in average MWs of capacity operating per half-hour period. Days with missing demand data are excluded. Market Power Index from column (1) of Table 3. ***,**,* denote statistical significance of the difference between actual and profit-maximizing outputs at the 1, 5 and 10% levels respectively. Statistical significance is assessed by regressing the difference in outputs in each half-hour period on a constant, allowing for heteroskedasticity and correlation between the regression residuals from different half-hour periods on the same day.

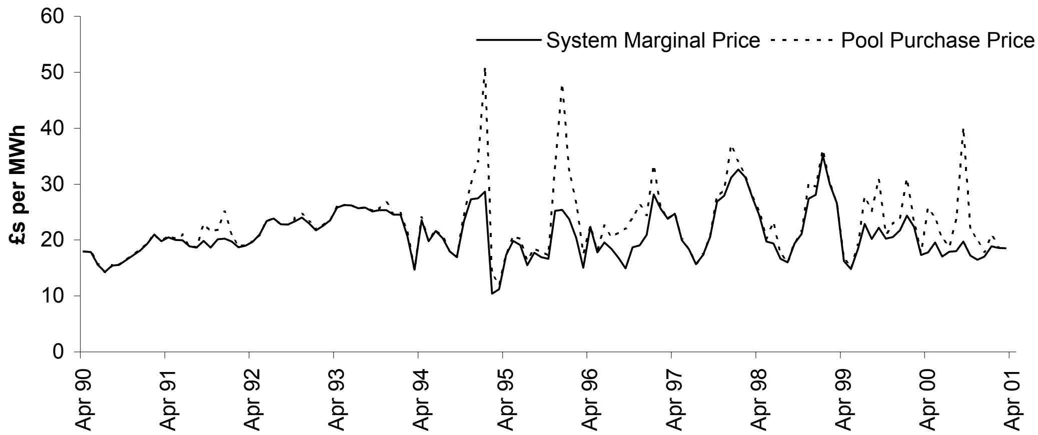
Table 5: Testing Best Response Bidding Behavior for NP and PG - Robustness Checks

		National Power					PowerGen				
			Estimated Profit-Maximizing Average Outputs Assuming 80% Contract Cover					Estimated Profit-Maximizing Average Outputs Assuming 80% Contract Cover			
			(1)	(2)	(3)	(4)		(5)	(6)	(7)	(8)
Quarter	Market Power Index	Estimated Actual Output	Average Fuel Prices	Unit Start-Up Costs	Drop 20 Periods Around Peaks	Allow Bids + or - 25%	Estimated Actual Output	Average Fuel Prices	Unit Start-Up Costs	Drop 20 Periods Around Peaks	Allow Bids + or - 25%
Q1 1995	0.23	13,609	12,235 ***	12,177 ***	12,358 ***	13,453	11,303	10,134 *	10,104 *	10,354	11,031
Q2 1995	0.34	10,380	9,755 **	9,956	9,917 *	10,325	7,496	7,048 *	7,421	7,008 *	8,278 **
Q3 1995	0.27	8,930	8,329 **	8,761	8,523 **	8,794	6,559	5,929 ***	6,399	5,760 ***	6,382
Q4 1995	0.36	11,445	11,252	11,226	11,269	11,599	8,745	9,253	9,303	9,267	9,426 **
Q1 1996	0.27	13,145	12,765	12,282 *	12,390 *	12,975	10,114	9,847	9,648	9,590	10,333
Q2 1996	0.35	8,942	8,281 ***	8,676	8,513	8,832	7,446	7,498	7,629	7,478	7,597
Q3 1996	0.27	7,404	6,181 ***	6,154 ***	6,427 ***	7,068	6,851	5,953 ***	6,319 *	6,301 *	6,805
Q4 1996	0.35	7,802	8,386	8,607 *	8,391	8,728 ***	8,052	8,568 *	8,670 **	9,007 ***	8,706 ***
Q1 1997	0.50	8,340	9,590 ***	9,548 ***	9,400 ***	9,190 ***	7,728	9,755 ***	9,755 ***	9,801 ***	8,744 ***
Q2 1997	0.43	5,987	7,552 ***	7,737 ***	7,821 ***	7,361 ***	5,633	7,397 ***	7,397 ***	7,528 ***	7,050 ***
Q3 1997	0.30	6,636	7,163 **	6,363	7,679 ***	6,945	5,985	6,652 ***	6,603 **	6,765 ***	6,411 *
Q4 1997	0.56	6,997	9,317 ***	9,348 ***	8,859 ***	8,630 ***	6,785	8,921 ***	8,940 ***	8,778 ***	8,190 ***
Q1 1998	0.59	8,040	10,162 ***	10,162 ***	9,946 ***	9,162 ***	7,076	9,800 ***	9,953 ***	9,997 ***	8,574 ***
Q2 1998	0.45	7,565	9,081 ***	8,978 ***	9,187 ***	8,473 ***	5,965	7,489 ***	7,489 ***	7,771 ***	7,110 ***
Q3 1998	0.34	7,352	8,003 ***	7,865 **	7,844 **	7,772 **	5,827	6,736 ***	6,601 **	6,374	6,459 ***
Q4 1998	0.55	7,189	8,501 ***	8,490 ***	8,583 ***	7,982 ***	6,176	7,587 ***	7,555 ***	7,722 ***	7,197 ***
Q1 1999	0.63	6,951	8,188 ***	8,196 ***	8,189 ***	7,801 ***	6,117	7,395 ***	7,395 ***	7,404 ***	6,999 ***
Q2 1999	0.32	5,389	6,632 ***	6,531 ***	6,395 ***	5,920 **	5,614	6,770 ***	6,632 ***	6,731 ***	6,397 ***
Q3 1999	0.52	5,487	6,556 ***	6,569 ***	6,570 ***	6,168 ***	4,288	5,686 ***	5,725 ***	5,688 ***	5,287 ***
Q4 1999	0.50	6,259	7,913 ***	8,015 ***	8,015 ***	7,509 ***	5,009	6,722 ***	6,722 ***	6,710 ***	6,064 ***
Q1 2000	0.50	5,128	6,313 ***	6,525 ***	6,528 ***	5,783 ***	4,962	6,695 ***	6,795 ***	6,635 ***	5,733 ***
Q2 2000	0.40	4,154	4,442 ***	4,576 ***	4,466 ***	4,552 ***	4,074	5,777 ***	5,642 ***	5,652 ***	4,964 ***
Q3 2000	0.40	3,210	3,542 **	3,482 *	3,471 *	3,351 **	2,960	4,109 ***	3,884 ***	4,027 ***	3,710 ***

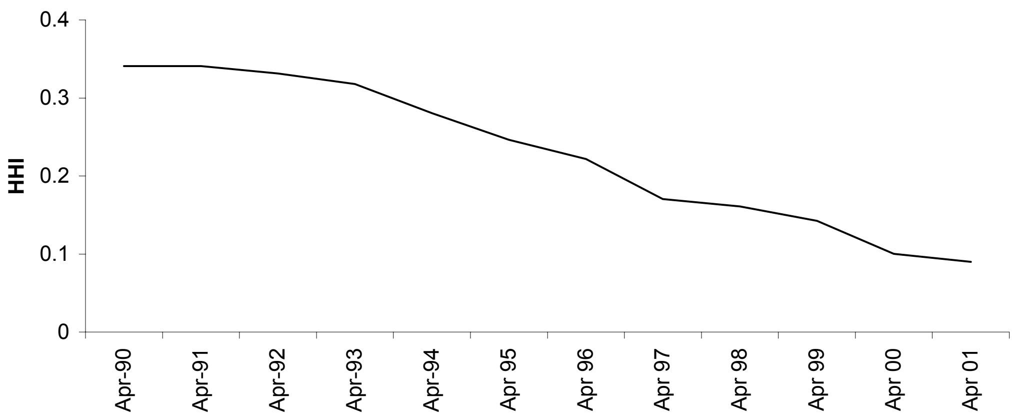
Notes: same as Table 4. Eastern earn-out included in comparison of profits from different bids.

Fig. 1: Pool Prices, Market Concentration and Fuel Costs 1990-2001

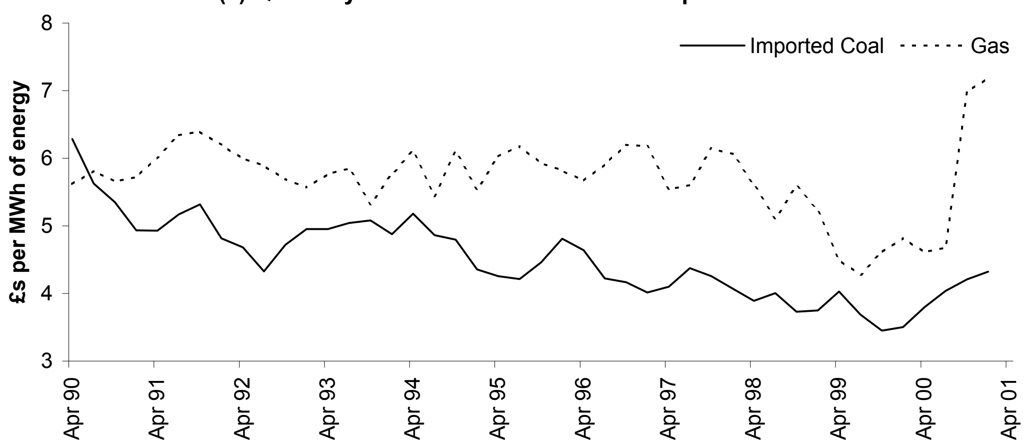
(a) Monthly Average Pool Prices



(b) Herfindahl-Hirschmann Index for Generating Capacity
in April each year



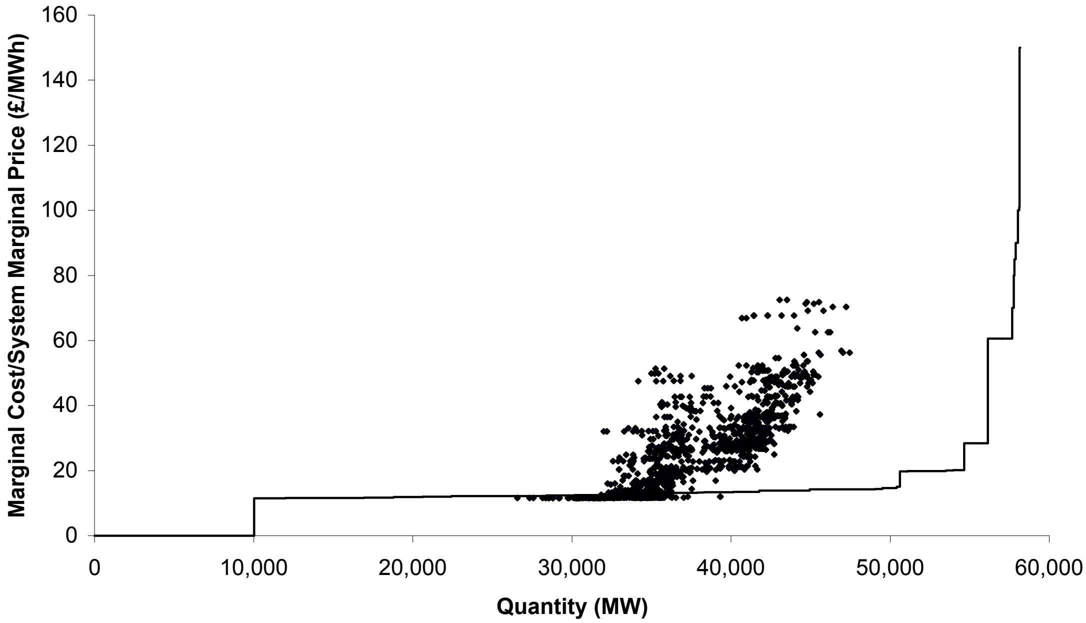
(c) Quarterly Prices of Natural Gas and Imported Coal



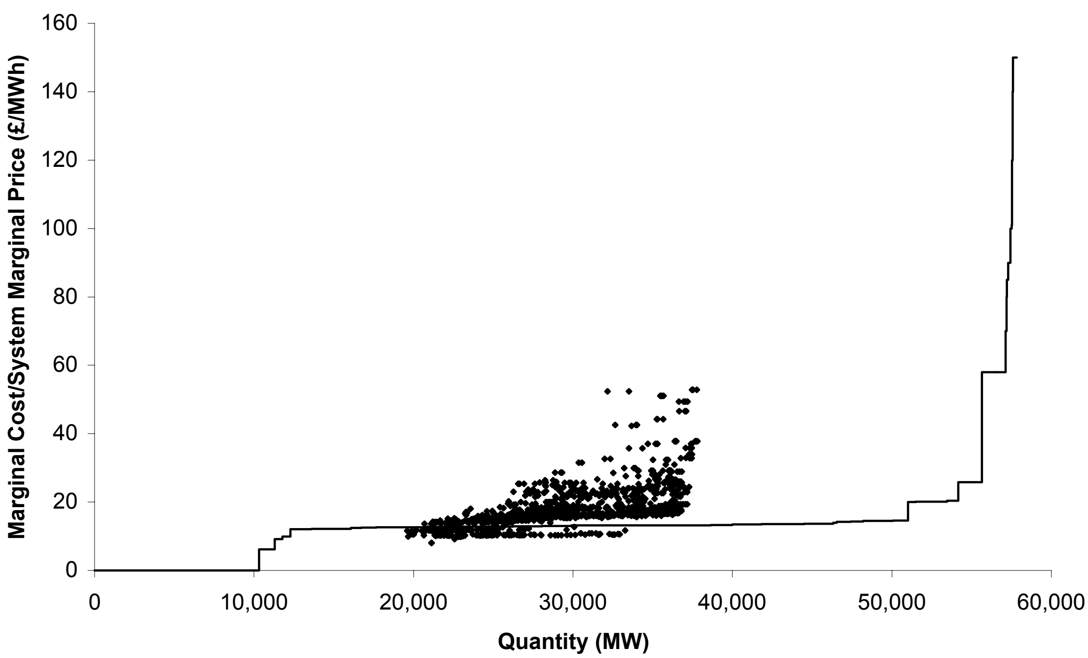
1995-2001. HHI data for 1990-1994 comes from generator capacity shares listed in Monopolies and Mergers Commission (1996a), p. 90. Imported steam coal and natural gas prices from sources listed in Appendix A.

Fig. 2: Aggregate Marginal Cost Functions and Pool Prices and Quantities

(a) February 1997



(b) August 1997



Note: nuclear units are assumed to have zero marginal cost and coal, oil, CCGT, OCGT, nuclear and pumped storage units are given their expected availability given NERC forced outage rates for coal, oil, CCGT, OCGT, nuclear and pumped storage units and the actual availability of new units, demand side bidders and the interconnectors at noon on the first Monday of the month.

Fig. 3: Monthly Market Power Index by Level of Demand

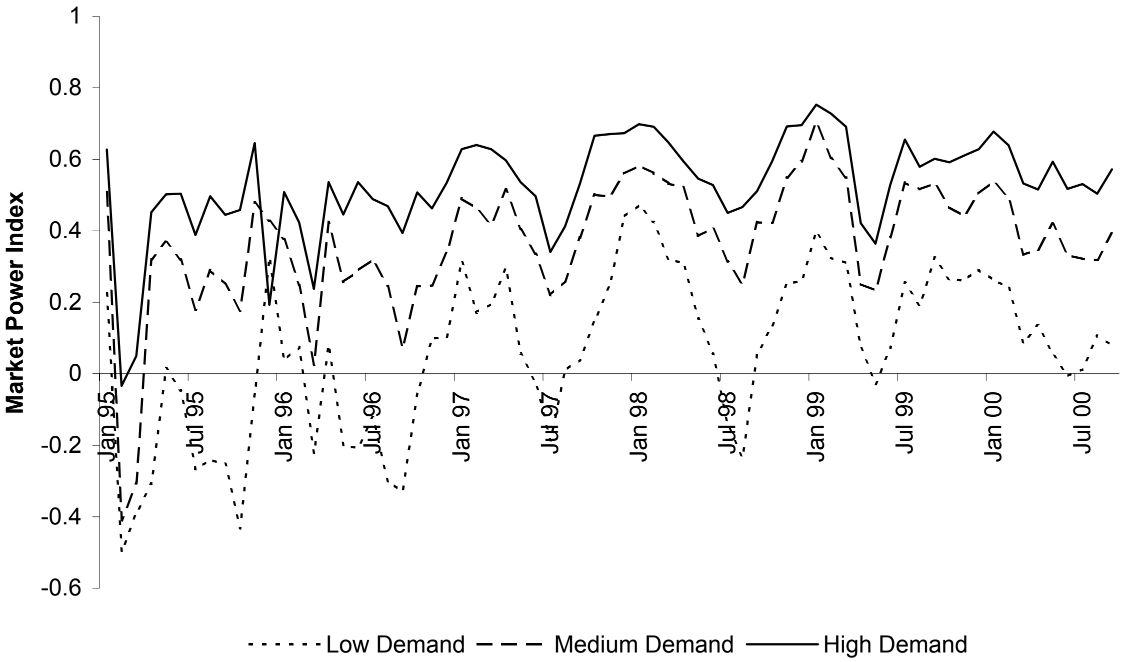
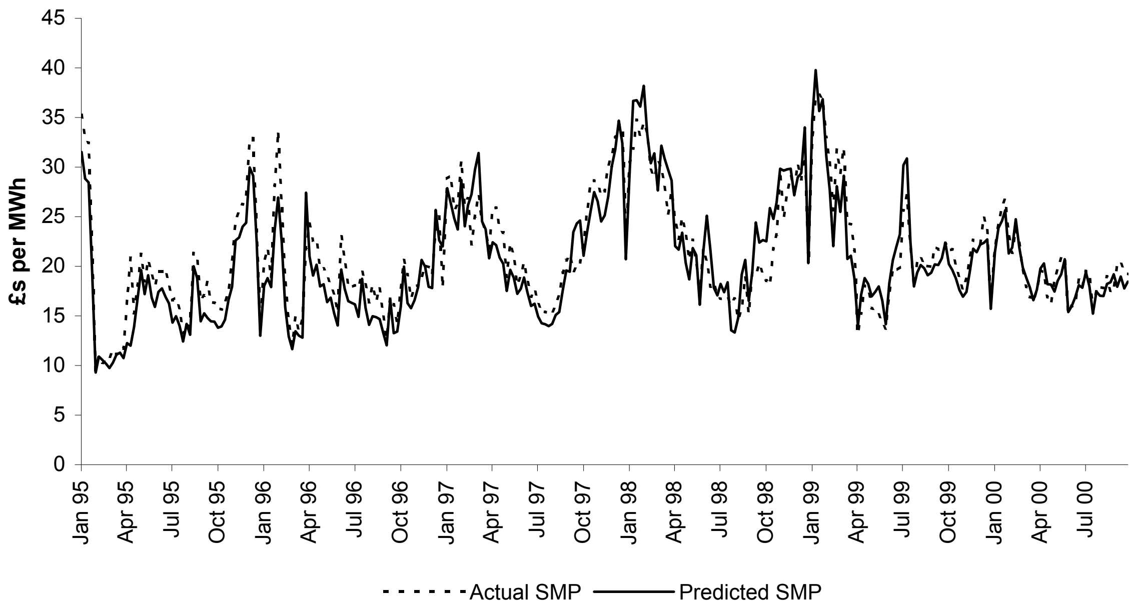


Fig. 4: Performance of the Scheduling Algorithm

(a) Comparison of Actual and Predicted Weekly Average Values of the System Marginal Price



(b) Difference Between Actual and Predicted SMP by Half-Hour Period

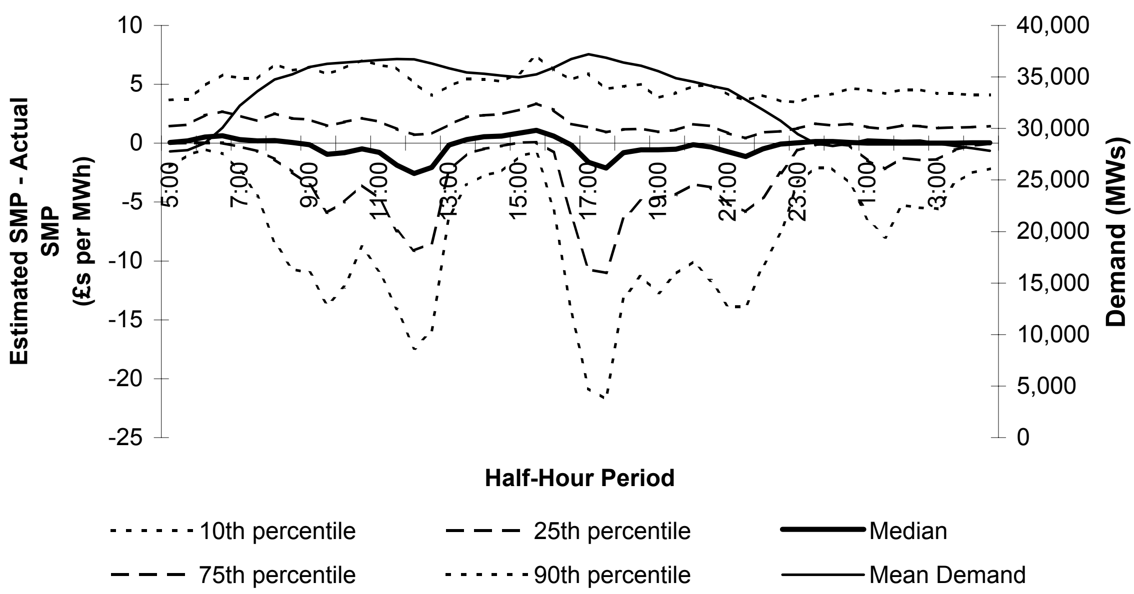
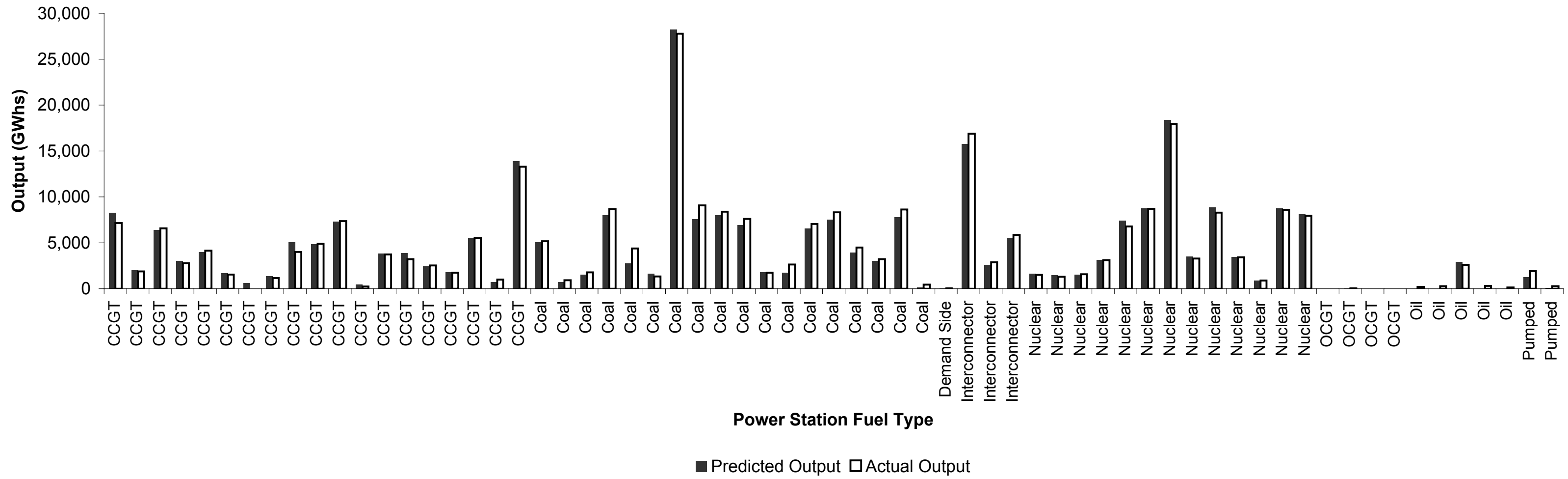


Fig. 4 cont.: Performance of the Scheduling Algorithm

(c) Comparison of Actual and Predicted Output of Power Stations 1996/97



(d) Comparison of Actual and Predicted Output of Power Stations 1999/00

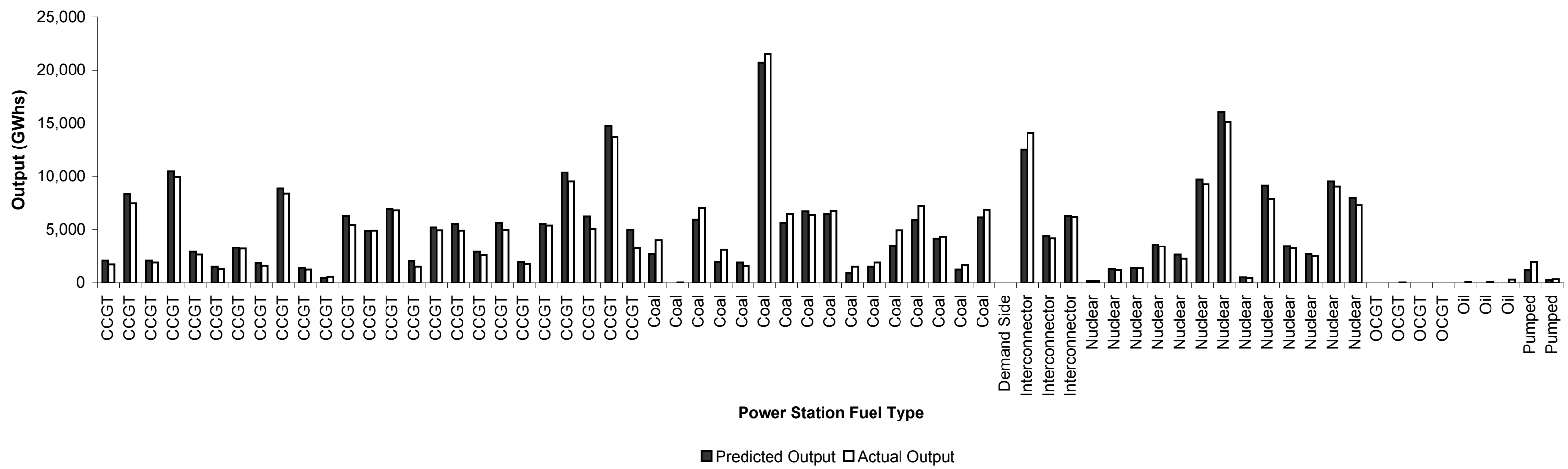


Figure 5: Table A Bids