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Abstract

This paper shows that generators exercised increasing market power in the England and Wales wholesale electricity market in the second half of the 1990s despite declining market concentration. It examines whether this was consistent with static, non-cooperative oligopoly models, which are widely used to model electricity markets, by testing the static Nash equilibrium assumption that each generator chose its bids to maximize its current profits taking the bids of other generators as given. It finds a significant change in behavior in late 1996. In 1995 and 1996 generator behavior was consistent with the static Nash equilibrium assumption if the majority of their output was covered by financial contracts which hedged prices. After 1996 their behavior was inconsistent with the static Nash equilibrium assumption given their contract cover but it was consistent with tacit collusion.

Keywords: static oligopoly models, market power, Nash equilibrium, tacit collusion, electricity markets

JEL Classification Numbers: C72, D43, L13, L51, L94

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1 Introduction

I estimate how much market power generators exercised in the England and Wales (E&W) wholesale electricity market (the Pool) from 1995 to 2000. I find that they exercised more market power from 1997 to 2000 than in 1995 or 1996 even though the market structure became much less concentrated over time. I examine whether this pattern was consistent with static oligopoly models which are widely used to predict the potential for market power in electricity markets (e.g., Green and Newbery (1992) for E&W and Borenstein and Bushnell (1999) for California). I test whether the bids of the largest generators, National Power (NP) and PowerGen (PG), were consistent with the static Nash equilibrium behavioral assumption that each generator chose its strategy (bids) to maximize its current profits taking the strategies of other generators as given. The test involves comparing estimates of a generator's profits from its actual bids with estimates of the profits that it could have made from using a set of alternative bids. This analysis is possible because there is relatively good information on unit operating costs in electricity markets.

While static oligopoly models are widely used, there are at least three reasons why we might expect outcomes other than static Nash equilibria in wholesale electricity markets. First, several large generators typically interact on a daily basis and aggregate demand is inelastic, creating almost ideal conditions for tacit collusion to be supported as an equilibrium in a dynamic, rather than static, oligopoly model. Collusion would result in generators exercising more market power than in a static model. Second, electricity markets are closely monitored by regulators who want to prevent generators exercising market power, so they might exercise less market power than in a static model. Third, generators and electricity supply companies can sign financial contracts which hedge future wholesale market prices. These contracts reduce generators' incentives to raise Pool prices and could lead to generators exercising less market power than in a static model without contracts.

I find that generators' behavior was not consistent with a single oligopoly model. In particular, there appears to be a change in behavior in late 1996, soon after the end of an undertaking by NP and PG to keep average prices below a price cap. In 1995 and 1996, NP and PG's bids were approximately consistent with static Nash equilibrium behavior if, as the evidence suggests, the majority of their output was covered by hedging contracts. These contracts can explain why prices were close to marginal cost even though the market was, in effect, a duopoly with capacity constraints. On the other hand, their bids were too low to be consistent with a static Nash equilibrium without contracts. From late 1996 to the end of my data in September 2000 I find that generators submitted bids which were too high to be consistent with static Nash equilibrium behavior if most of their output was covered by hedging contracts. Instead generators' behavior was consistent with them taking contracts as given but tacitly colluding to raise Pool prices. Their behavior was also consistent with an attempt to increase current prices in order to try to increase prices in future contracts.

The analysis is also relevant for evaluating the actions of regulators in the E&W market. The price undertaking negotiated by the regulator, OFFER (later OFGEM), in April 1994 appears to have constrained the behavior of generators, although they still exercised as much market power as they would have done in a static oligopoly model given their contract cover. On the other hand, the divestiture of plant, negotiated by OFFER in 1994 and 1998, did not prevent generators exercising significant market power up to September 2000 despite the predictions of Green's (1996) and Brunekreeft's (2001) static oligopoly models. The results also cast some doubt on the Competition Commission's conclusion in 2001 that declining market concentration after 1994 had reduced the problem of market power when deciding that conditions prohibiting the abuse of substantial market power should not be inserted into generators' licences.[1]

This paper contributes to the literature on the E&W electricity market. Static oligopoly models with contracts (e.g., Newbery (1998) and Green (1999)) and without contracts (e.g., Green and Newbery (1992) and von der Fehr and Harbord (1993)) have been used to predict or explain Pool prices.

[1] Competition Commission (2001), p. 5.

Wolfram (1999) showed that generators exercised less market power from 1992 to 1994 than predicted by Green and Newbery (1992). She also found that market power was less sensitive to large changes in the level of contract cover than one would expect in a static oligopoly model with contracts, but that it was sensitive to actions taken by the regulator. A number of recent papers, several of them citing an earlier version of the current paper (Sweeting (2001)) have examined Pool data from the late-1990s. Evans and Green (2003) find that the Lerner index fell significantly just after the end of my data period and they suggest that tacit collusion may have broken down once it was known that the Pool would be replaced by the New Electricity Trading Arrangements (NETA) in March 2001. Macatangay (2002) identifies patterns in NP and PG's bidding which he suggests are consistent with tacit collusion. Bower (2002) and Newbery (2003) suggest that the incumbent generators may have exercised more market power from 1998 to 2000 because of a government moratorium on approving the construction of new combined cycle gas turbine (CCGT) capacity which may have reduced the need for entry deterrence. Newbery (2003) also suggests that NP and PG may have raised prices in 1999 and 2000 to increase the resale value of power stations which they were trying to sell. This paper provides direct evidence that the generators were exercising more market power in the late-1990s and that NP and PG were restricting output to raise prices by more than would have been expected in a static oligopoly model with contracts.

Two other papers assess whether generator bids are consistent with the static Nash equilibrium assumption that generators maximize current profits. Wolak (2000) examines one Australian generator in a market where prices were close to marginal costs and finds that its bids were approximately consistent with profit maximization given its contract cover. This is similar to my result for NP and PG in 1995 and 1996 when prices in E&W were close to marginal costs. Hortacsu and Puller (2004) examine several generators in the Texas balancing market and find that while the largest generator approximately maximized its profits, other generators failed to trade in the market when it was profitable to do so. This paper examines similar questions in the E&W market in the late-1990s where the pattern of increasing market power and declining market concentration provides *prima facie* evidence of deviations from Nash equilibrium behavior.

Section 2 provides brief descriptions of the Pool and the changes in market structure. Section 3 shows that market power, measured by the difference between market and competitive prices, increased in the late-1990s. Section 4 examines whether NP and PG's bids were consistent with the static Nash equilibrium behavioral assumption. Section 5 concludes.

2 The England and Wales Electricity Pool in the 1990s

The Pool operated as a multi-unit uniform price auction for pricing and scheduling the generation of electricity. Every generator submitted a set of price bids for each generating unit each day together with the unit's available capacity in 48 half-hour periods. The System Operator (National Grid Company (NGC)) used these bids and a price-inelastic demand forecast to schedule production in each period using an algorithm called GOAL. A small number of large users, "demand-side bidders", submitted bids in the same way as generators to reduce their demand. The System Marginal Price (SMP) in a period was determined by the "Genset Price" of the highest priced unit scheduled to produce when transmission constraints were ignored. Available units also received a capacity payment which depended in a highly non-linear way on the amount of spare capacity. The Pool Purchase Price (PPP) was the sum of the SMP and this capacity payment. The Pool Selling Price (PSP), paid by regional electricity supply companies (RECs) purchasing from the Pool, combined the PPP and additional payments reflecting capacity payments for units not scheduled to produce, transmission constraints, transmission losses and ancillary services. Further details of the Pool can be found in Electricity Pool (1996a, 1996b, 1999).

When the Pool was created in 1990 the newly-privatized NP and PG owned 47% and 30% of total capacity and all of E&W's coal, oil and open cycle gas turbine (OCGT) units. State-owned Nuclear

Electric operated all of E&W's nuclear power stations (14%). NGC owned two pumped storage stations (3%), which are important in meeting unexpected demand fluctuations, and Electricité de France (EdF) and two Scottish generators supplied electricity over interconnectors with France and Scotland (5%).[2] Nuclear units are inflexible so NP and PG's coal units provided most of the variation in output and these units typically set the SMP.

NP and PG's dominance of generation decreased over time for three reasons. First, CCGT units, mainly operated by new entrants, entered production. There were no CCGT units in 1990, but they accounted for 14% and 30% of total capacity in 1995 and 2000 respectively.[3] These units tended to operate continuously (as "baseload") and even in 2000, when natural gas prices were relatively high, coal units set the SMP in over 80% of half-hour periods. Second, NP and PG closed 5.4 GW of older coal, OCGT and oil capacity (11% of their 1990 capacity). Third, NP and PG divested coal power stations. In April 1994 NP and PG undertook to divest plant and keep average prices below a price cap for two years in order to avoid being referred to the Monopolies and Mergers Commission. The divestiture took place in July 1996 when 5 power stations (6.2 GW of capacity) were leased to Eastern Group.[4] In 1998 OFFER negotiated further divestitures when NP and PG needed its permission to vertically integrate with RECs.[5] In July 1999 PG sold 3.9 GW of capacity to Edison First Mission (Edison) which had bought NGC's pumped storage stations in December 1995. NP sold 3.9 GW of capacity to AES in December 1999. In March 2000 it sold 1.9 GW of coal capacity to British Energy (BE), the owner of E&W's more modern nuclear plants since March 1996, and 650 MW of CCGT capacity to NRG. After September 2000 PG made further plant sales to EdF.

Figures 1(a) and (b) shows how the major generators' shares of total capacity and the SMP-setting

[2] Capacity shares listed in OFGEM (1998a), p. 42.

[3] Shares for 1995 and 2000 based on data described in Appendix A. The UK government's 1998-2000 moratorium on CCGT projects only applied to the approval of new projects and not to the construction of units which had already been approved, so that a number of CCGT units entered production during these years.

[4] As part of the lease Eastern paid NP and PG £6 for each MWh hour the units generated, increasing its marginal costs. This arrangment came to an end in January 2001 when Eastern bought the plants outright (Bower (2002)).

[5] Competition Commission (2001), p. 153.

unit changed from 1995 to 2000. The data is described in Appendix A.[6] NP and PG's combined share of capacity fell from almost 65% in January 1995 to less than 30% in September 2000 when independently-owned CCGT units made up 25% of capacity. The HHI based on capacity fell from over 0.25 in January 1995 to less than 0.1 in September 2000, making the market "unconcentrated" by the U.S. Department of Justice's Horizontal Merger Guidelines criteria.[7] NP and PG's combined share of the SMP-setting unit fell from over 80% in 1995 to around 30% in 2000, when AES, Eastern, Edison, BE and EdF each set the SMP in over 6% of half-hour periods. The HHI based on the SMP-setting unit fell from 0.4229 in early 1995 to 0.1567 in the summer of 2000, making the market only "moderately concentrated" by this measure.

3 Market Power 1995-2000

This section shows that generators exercised more market power, as measured by the Lerner index, in the late-1990s than in 1995 or 1996. The Lerner index reflects the difference between the observed price and a competitive benchmark price, defined as the marginal operating cost of the highest marginal cost unit required to meet demand. A price-taking owner of the marginal unit would be indifferent to increasing its output at this price. Wolfram (1999), Borenstein et al. (2002) and Joskow and Kahn (2002) use a similar definition when estimating market power in electricity markets. The data contains information on generator bids, unit availability, forecast demand, fuel prices, unit efficiencies, the identity of the unit setting the SMP in each half-hour period and realized Pool prices from January 1995 to September 2000. Further details of the data and summary statistics are given in Appendix A.

The identity of the marginal unit can be estimated in a number of ways. In the text I present results using the unit which sets the SMP, which is identified in my data, as the marginal unit. This unit is the highest priced flexible unit which GOAL scheduled to generate when transmission constraints

[6] A unit's capacity is defined as the maximum capacity which it ever declares available.

[7] U.S. Department of Justice (1997), paragraph 1.51.

were ignored.[8] This approach implicitly takes into account technical constraints which prevented some units from being scheduled. Appendix B shows that the results are very similar if I estimate which unit was marginal based on estimates of demand and unit marginal costs.[9]

I calculate the marginal costs of coal, oil, CCGT and OCGT units using input fuel prices and estimates of unit efficiency. Input fuel prices come from publicly available quarterly data on the average fuel prices paid by major UK power producers. Pumped storage units raise water during off-peak periods for release during peak periods so I use the average PSP from midnight to 5am the next day as the fuel price and assume unit efficiencies of 66%. I calculate the Lerner index as $\frac{SMP-MC}{SMP}$ where MC is the estimate of the marginal cost of the unit setting the SMP.[10] I assume that EdF, the Scottish generators, demand-side bidders and owners of cogeneration units bid competitively so that when they set the SMP the Lerner index is zero. Nuclear units never set the SMP. I drop the last day of data as pumped storage costs cannot be calculated, 14 half-hours because the marginal unit is not recorded and 15 half-hours with SMPs less than £1/MWh as these have a disproportionately large effect on the average values of the Lerner index. The Lerner index is calculated for the remaining 100,721 half-hour periods.

Table 1 column (1) presents the time-average Lerner index for each financial year (April to March) from 1995 to 2000. The index was negative in early 1995 because of the low SMPs in February and March 1995 (Figure 2(a)) which allowed NP and PG to meet their price undertaking for the 1994/95 financial year.[11] The average index was positive but quite small (0.041) in 1995/96 but it increased steadily to 0.329 in 1998/99 and fell only slightly to 0.285 in the summer of 2000. The Lerner index increased because Pool prices fell less dramatically than coal and natural gas prices. For example, coal

[8] Some units are inflexible because their technical constraints, as declared by the unit's owner, require that they operate in a particular way. Inflexible units cannot set the SMP.

[9] Evans and Green (2003) and Burns et al. (2004) estimate the Lerner index for 1996 to 2001 and find a very similar pattern from 1996 to 2000, with the index peaking in 1998/99. They also find that the Lerner index declined significantly in October and November 2000 after the end of my sample period.

[10] Wolfram (1999) argues that it is appropriate to use the SMP to calculate the Lerner index because the PPP and PSP include capacity payments while the cost estimates do not include the costs of making capacity available.

[11] OFFER (1998a), p. 27.

prices fell from £4.67 per MWh of energy to £4.10/MWh and natural gas prices fell from £6.70/MWh to £6.31/MWh between January 1995 and January 2000. Figure 2(b) shows the time-series of the monthly average Lerner index. Generators exercised less market power in the low demand summer months and more market power in every month in 1998/99 than in 1995/96.

Wolfram (1999) estimates the average Lerner index for 1992/93, 1993/94 and 1994/95 based on the months of January, February, March, April, July and November.[12] Column (2) presents my results for these months as well as her estimates for the earlier years. Generators exercised less market power from January 1995 to April 1997 than in Wolfram's period, but they exercised more market power after April 1997.

Table 1 columns (3)-(7) present robustness checks. Column (3) and Figure 2(c) use commodity market fuel prices, rather than the higher average prices paid by generators, as input fuel prices. This is appropriate if generators traded in commodity markets on the margin. The index increases in every month, becoming positive in early 1995, and the pattern of increasing market power up to 1998/99 remains. Column (4) and Figure 2(c) add £2/MWh to the marginal costs of all units except those that I assume bid competitively. This addition is reasonable if there were significant non-fuel components of marginal costs and it is equal to one-sixth of the average fuel costs of a coal unit. The index falls in every year by a similar amount. The index also peaks in 1998/99 in column (5) where I add to marginal costs an amount which increases linearly from £0/MWh on January 1 1995 to £2/MWh on September 30 2000 based on AES's and BE's claims to the Competition Commission that the decline in fuel costs overstated the decline in operating costs over the 1990s.[13] Column (6) uses only those half-hour periods in which coal units set the SMP. The index increases during the late-1990s by more than in column (1) because of the fall in coal prices and the fact that the generators which I assume bid competitively set the SMP more often in 1999 and 2000.

Figure 3(d) presents the index for different levels of demand. I classify the twelve lowest demand

[12] Wolfram calculated the Lerner index by estimating the identity of the marginal unit.

[13] Competition Commission (2001), p. 130.

periods each day as low demand periods, the twelve highest demand periods as high demand periods and the remainder as medium demand periods. Most models predict that generators exercise more market power at peak demand and, consistent with this prediction, the index is always highest in the high demand periods. Generators exercised more market power at every demand level in 1998 and 1999 than in 1996, with slightly larger increases for low and medium demand periods.

In static oligopoly models equilibrium market power tends to decrease when the market structure is more fragmented because, holding everything else equal, each generator faces more elastic residual demand and has less inframarginal capacity which can profit if it increases the market price.[14] However, increasing market power does not prove that there were deviations from static Nash equilibrium behavior because static oligopoly models may have multiple Nash equilibria, so that the pattern might be explained by a switch from a low market power Nash equilibrium in 1995 and 1996 to a high market power Nash equilibrium in the late-1990s.[15] For this reason, it is necessary to test the Nash equilibrium behavioral assumption that each generator maximizes its current profits taking the bids of other generators as given more directly.

4 Testing Static Nash Equilibrium Behavior

I test the static Nash equilibrium behavioral assumption by comparing a generator's profits from its actual bids with estimates of the profits that it could have made from a set of alternative bids. This allows me to identify periods when behavior was approximately consistent with Nash equilibrium behavior and, when it was not, whether the generator deviated by submitting bids which were too low (so profits would have been increased by unilaterally submitting higher bids to produce less at higher prices) or too high (so profits would have been increased by unilaterally submitting lower bids to produce more at lower prices). I analyze the bids of NP and PG, the largest non-nuclear generators

[14] Green (1996), using a static supply function equilibrium model, and Brunekreeft (2001), using a static multi-unit auction model, show that divestiture of capacity tends to lower Nash equilibrium Pool prices.

[15] For example, Green and Newbery's (1992) static supply function equilibrium model has a range of Nash equilibria.

throughout my time period.

Section 4.1 describes the method. Section 4.2 presents the results and Section 4.3 discusses their interpretation. The data used is the same as in Section 3 and it is described in Appendix A. I reduce the computational burden by focusing on Wednesdays, but I show that the results for Saturdays are very similar. I drop observations from the first week of January 1997 because the unit availability data in that week has different unit codes to the bid data.

4.1 Method

A unit's daily bid had 5 price elements (start-up, no load and three incremental energy prices), 48 half-hour levels of available capacity and technical parameters, such as ramp rates, which constrained how the unit could be operated. This gave the owner of multiple units a very large strategy space and makes it infeasible to calculate the exact bids which would have maximized its profits. I make a number of simplifications to create a tractable problem.

If generator i owns units G_i, makes price bids b_i and declares unit availabilities a_i then I specify its current day profits as

$$\pi_i = \sum_{t=1}^{48} \sum_{j \epsilon G_i} (SMP_t(b_i, b_{-i}, a_i, a_{-i}, \theta) - c_j) q_{jt}(b_i, b_{-i}, a_i, a_{-i}, \theta) \tag{1}$$

where q_{jt} is unit j's production in half-hour period t, c_j is j's constant marginal cost and θ is a vector of parameters including demand in each half-hour period. b_{-i} and a_{-i} are the bids and unit availabilities of other generators. Equation (1) ignores the effect of financial hedging contracts on profits. I show how assumptions on contract cover can be included in the analysis in Section 4.2.2. It also ignores capacity payments and payments resulting from transmission constraints. Section 4.2.2 discusses whether the existence of these payments could explain the results.

I take unit availability as given. If i uses a static Nash equilibrium strategy then its price bids should be equal to b_i^* where

$$b_i^* = \arg\max_{b_i} \sum_{t=1}^{48} \sum_{j \epsilon G_i} (SMP_t(b_i, b_{-i}, a_i, a_{-i}, \theta) - c_j) q_{jt}(b_i, b_{-i}, a_i, a_{-i}, \theta) \tag{2}$$

i.e., the bids maximize i's profits taking the availability of its own units as well as those of other generators as given. This implicitly assumes that a generator knows the bids of other generators when bidding which is partly justified by the fact that generators do not change their bids every day.[16] The analysis involves three steps: (i) the calculation of unit quantities and prices for a generator's actual bids; (ii) the calculation of profits for a generator's actual bids using estimates of unit costs; and (iii) creating alternative bids and calculating profits for each of these alternatives. I note that considering only a limited set of alternative bids makes me more likely to find that a generator's actual bids maximized its profits.

4.1.1 Calculation of Prices and Unit Quantities Given Unit Bids

The Pool's scheduling algorithm (GOAL) used unit bids and NGC's demand forecasts to schedule production in each half-hour period. GOAL minimized total costs taking into account how one period's production schedule affected costs in another period through technical constraints and start-up costs. As GOAL and unit technical parameters are not available, I have developed an alternative algorithm which is described in detail in Appendix C. It is partly based on Section 8 of the "Pool Rules" (Electricity Pool (1999)) which describes how GOAL created the schedule. My algorithm incorporates a number of plausible constraints on unit operation. My algorithm uses the same formulae as GOAL to calculate the SMP in each period given the unconstrained schedule which ignores transmission constraints.

It is important that my algorithm does a reasonable job of predicting prices. I can assess its performance using generators' actual bids. Figure 3(a) shows the actual and predicted weekly averages

[16] For example, an average of 78% of available units had exactly the same price bids as on the previous day.

of the SMP using every day in my sample period. The correlation coefficient between the series is 0.9354. The performance is worst in 1998 when I overestimate SMP by, on average, £2/MWh. This is explained by generators declaring more units to be technically inflexible in 1998 than in other years because inflexible units cannot set the SMP.[17] As I have no data on these declarations I cannot adjust for them. Figure 3(b) examines the performance of the algorithm as demand varies during the day by showing percentiles of the difference between the actual and predicted SMP in each half-hour period. The heavy line shows median demand. The median error is close to zero in every period and the extreme percentiles show that I predict prices accurately at the beginning and end of the schedule day and between the demand peaks in the afternoon. However, I underestimate the SMP at peak demand on a significant number of days. This may reflect unit-specific constraints which made it necessary to use more expensive units. Figure 3(c) shows the pattern for weekends. Weekends have smoother demand and my algorithm predicts peak prices with greater accuracy.

I also need to accurately predict unit output. Unfortunately daily unit output data is not available. However, OFGEM kindly gave me access to production figures for power stations, which can contain several units, for each financial year. The hollow columns in Figure 4(d) show a station's actual output and the solid columns show its estimated output in 1996/97. The pattern in other years is similar. I do not expect an exact match because actual production reflects transmission constraints and responses to unexpected changes in demand which my algorithm does not try to incorporate. The match is, however, very good. I underpredict the output of pumped storage stations which are used to meet unexpected increases in demand.

4.1.2 Calculation of Profits Given Prices and Unit Quantities

It is straightforward to estimate a generator's profits given prices and unit quantities. The revenues of a unit in a half-hour period equal its output multiplied by the SMP. I calculate unit costs assuming

[17] OFGEM (1999a), p. 9 reports that generators declared 39% of available capacity "totally inflexible" in 1998 compared with 23% in 1997. Over 50% of available capacity was frequently "totally inflexible" in the summer of 1998.

that every unit has a constant marginal cost which can be calculated by dividing the estimated fuel price per MWh of energy by an estimate of the unit's efficiency.[18] I consider in Section 4.2 whether start-up costs could explain the results. Generator profits are calculated by adding per-period unit profits across periods and units.

4.1.3 Specification of Alternative Bids

I consider changes to a generator's bids which increase or decrease all of its price bids for coal, CCGT and oil units by the same proportion. I consider reducing bids by 50%, 30%, 25%, 20%, 15%, 10% or 5% and increasing bids by 5%, 10%, 15%, 20%, 25%, 30%, 50% and 100%. This gives 15 sets of alternative bids per generator per day.[19]

For each set of alternative bids I re-estimate unit quantities, prices and generator profits with the bids of other generators unchanged. I then identify the bids which maximize the generator's profits. Even if a generator was trying to maximize its profits, I might not find that a generator's actual bids maximized its profits due to the simplifications made in estimating profits. I measure the difference between a generator's actual bids and the bids which I estimate maximize its profits by calculating the difference in the average amount of the generator's capacity operating in each half-hour period (output). I examine whether these differences, are, on average, significantly different from zero over a six month period.

4.2 Results

I present a set of results which ignore the effect of financial hedging contracts on generator profits, before including contracts in the analysis. Section 4.3 discusses the interpretation of the results.

[18] The data is described in Appendix A. NP and PG only owned CCGT, coal, OCGT and oil units so it is not necessary to make assumptions about costs for other fuel types.

[19] I also computed all of the results using a much larger set of alternative bids which allowed a generator to increase its bids for some units and decrease them for others. This much richer set of alternative bids gave qualitatively quite similar results but tested the hypothesis of whether a generator could profitably deviate by submitting higher or lower bids less directly. The only significant difference in the results is that I found that significant increases in output would have been profitable for both generators in 1999 and 2000 when I ignore contract cover.

4.2.1 Results Without Contracts

Table 2 presents the results for Wednesdays, using the average fuel prices paid by generators to calculate unit costs.[20] NP's results are on the left and PG's are on the right. The first column shows the generator's estimated output for its actual bids, the second column shows its output for the bids which maximize its profits and the third column gives the p-value for the two-sided t-test that these outputs are, on average, the same. If the generator's bidding was consistent with the static Nash equilibrium behavioral assumption that it maximized its current profits given the bids of other generators then the outputs should not be significantly different.

The results show a different pattern before and after the end of 1996. In 1995 and 1996 I estimate that both generators could have increased their profits in each six-month period by significantly reducing their output. The differences in output are all highly significant at the 1% level. Almost all of the profit-maximizing bids involve 100% increases which is the largest increase I consider. Larger reductions in output would almost certainly have been more profitable because prior to the 1996 divestiture NP and PG's capacity was required to meet demand in most half-hour periods. This made them residual monopolists facing inelastic residual demand. For example, in the first quarter of 1996 the total available capacity of generators other than NP was insufficient to meet forecast demand in 4,303 out of 4,366 half-hour periods, by an average of 6,352 MW. The available capacity of generators other than PG was insufficient to meet demand in 2,381 periods, by an average of 3,252 MW. This gave both generators the ability in many periods to unilaterally raise Pool prices to their maximum allowed level of £2,000/MWh (in 1990 prices). On the other hand, after March 1997, there is no significant difference (at the 5% level) between actual and profit-maximizing output in the majority of six-month periods for each generator which shows that their bidding was approximately consistent with static Nash equilibrium behavior for most of this period. I note, however, that PG could have

[20] These results use the SMP estimated by my algorithm as the price when calculating profits from generators' actual bids. The results are almost identical using the actual SMP.

increased its profits by significantly increasing its output (lowering its bids) after October 1999, after it had sold capacity to Edison.

4.2.2 Results with Contracts

The generators signed financial contracts, known as Contracts for Differences (CfDs), with RECs which hedged future Pool prices.[21] The typical contract specified a price and a quantity. If the Pool price was above the contract price then the generator paid the REC the difference in the prices for the contract quantity. A two-way CfD required the REC to compensate the generator if the Pool price was below the contract price. If p_t^P is the Pool price in period t, q_{it}^P is i's output in period t with production costs $c(q_{it}^P)$ and p_{it}^C is the contract price then i's period t profit when q_{it}^C is covered by two-way CfDs is

$$\begin{aligned} \pi_{it} &= p_t^P q_{it}^P - (p_t^P - p_{it}^C) q_{it}^C - c(q_{it}) && (3) \\ &= p_t^P (q_{it}^P - q_{it}^C) + p_{it}^C q_{it}^C - c(q_{it}) && (4) \end{aligned}$$

CfDs fix prices for contracted output and so only uncontracted output profits from an increase in the Pool price. This gives a generator with contracts more incentive to increase its output than one without contracts.[22] The existence of contracts could therefore explain why I find that NP and PG could have increased their profits in 1995 and 1996 by reducing their output. On the other hand, if most of NP and PG's output was covered by contracts after 1996 then it is likely that taking them into account will lead to the conclusion that they could have profitably increased their output. The publicly available evidence strongly suggests that as much as 90% of NP and PG's output was covered

[21] OFGEM (1998a), pp. 36-40 and Competition Commission (2001), pp. 131-141 describe the contract market. A CfD lasted between 12 and 18 months and was directly negotiated between a generator and an electricity supply company. Electricity Forward Agreements (EFAs) were similar instruments traded through brokers which had shorter durations.

[22] Green (1999) and Wolak (2000) describe the effect of contracts on generator bidding incentives in more detail.

throughout this period.[23]

Table 3(a) reports the results when I make the conservative assumption that each generator had contracts for a quantity equal to 70% of its estimated actual output in each half-hour period. Equation (4) shows that profits from different bids can be compared without knowledge of contract prices. There is no significant difference (at the 5% level) between PG's actual and profit-maximizing outputs in three of the four periods before September 1996. The differences for NP are still significant but smaller and a higher level of contract cover for NP could clearly result in these differences being insignificant as well. Therefore, if over 70% of their output was contracted then NP and PG's bids were consistent with static Nash equilibrium behavior prior to September 1996. On the other hand, after October 1996 I find that profit-maximization would have resulted in both generators significantly increasing their average output in every six-month period. The differences between actual and profit-maximizing output are roughly the output of between 2 and 4 large coal units (a large coal unit's capacity is between 500 MW and 600 MW), until 2000 when, as a result of divestitures, NP and PG had less available spare capacity.[24] If more than 70% of their output was contracted then larger increases in output would have been profitable. In the extreme case where 100% of actual output was contracted, a generator would have wanted to increase its output if the Pool price was greater than the operating costs of its lowest cost non-scheduled unit. Section 3 showed that prices were significantly higher than marginal operating costs from 1997 to 2000. I now briefly consider several robustness checks focusing on issues which might affect the conclusion that NP and PG could have increased their current profits by increasing their output in the late-1990s.

[23] OFGEM (1998a), p. 38 reports that 97% and 88% of total output was covered by CfDs in 1990/91 and 1996/97 respectively. Competition Commission (2001), p. 132, reports that "there are no precise figures for the volume of electricity traded via CfDs but estimates range from 60 to 90% of total volume supplied. OFGEM estimated that approximately 90% of demand was covered by contracts including EFAs" and, p. 137, that in July 2000 PG was "100% hedged through supply contracts to October 2000 and over 90% hedged for the full year". The estimates in OFGEM (1998a), Tables 5 and 9, suggest that PG was over-contracted in 1996/97 and that NP was contracted for over 95% of its output.

[24] For example, NP had an average of 5,305 MW of available capacity from March to September 2000. Of course, profit-maximization may also have involved NP and PG making more capacity available whereas I take availability as given.

Robustness Checks An increase in marginal costs makes increasing production less profitable. In Table 3(b) I add £2/MWh to the marginal costs of each unit. The differences between actual and profit-maximizing output after October 1996 are smaller than in Table 3(a) but they are still significant at the 1% level. Of course, units may have start-up costs as well as fuel costs incurred once the unit is operating. However, a generator can increase its output without increasing the number of start-ups if more units run continuously. Table 4 shows the number of units operating and the number of unit start-ups for each generator's actual and profit-maximizing bids. The greatest increase in NP's start-ups per day with profit-maximizing bids is 6.2 between April and September 1997. Almost all of these additional start-ups involve coal units. If starting a coal unit costs £2,450 (the median start-up bid of an available coal unit during these months) then start-up costs would have increased by an average of £15,435 per day. However, I estimate that NP would have increased its profits by an average of £257,641 per day (ignoring start-up costs) during these months by using its profit-maximizing bids, which suggests that I am not finding that NP and PG should have increased their production only because I ignore start-up costs.

Table 3(d) shows the results for Saturdays. Figure 3(c) shows that weekends have smaller demand peaks than weekdays and that my scheduling algorithm does better at predicting peak prices on weekends. I drop one Saturday in March each year because of ambiguities in the data when the clocks move forward. After October 1996 I find that both generators could have increased their profits on Saturdays by increasing their output although these increases are only significant at the 5% level for NP before September 1997 when the Lerner index was still relatively low.

My calculations ignore how bids affect capacity payments. All available units received a capacity payment which was a decreasing function of the SMP or the unit's bid whichever was higher. Therefore capacity payments gave generators an incentive to lower, rather than raise, their bids. My calculations also ignore payments arising from transmission constraints. When there were transmission constraints units in areas of excess demand were more likely to be required to generate and so had an incentive to increase their bids. However, OFGEM (1999a) reports that the total costs of paying generators above the SMP due to transmission constraints in 1998/99 was only £21 million or £57,534 per day. This compares with an estimated increase in NP's daily profits from submitting its lower profit-maximizing bids of £464,290 per day (£425,703 for PG) during the same year so it is unlikely that constrained-on revenues can explain why generators appear to have bid too high. Units in areas with excess generation had an incentive to reduce their bids in order to be scheduled.[25]

4.3 Discussion

NP and PG's bidding from 1995 to 2000 was not consistent with a single static oligopoly model and, in particular, there appears to have been a change in generator behavior in late 1996. In 1995 and 1996 their bids, which led to prices being close to competitive levels, were consistent with static Nash equilibrium behavior in a model where most of their output was covered by contracts (e.g., Newbery (1998) or Green (1999)). After 1996 their behavior was inconsistent with this model because, with prices significantly above marginal costs and the prices for the majority of their output fixed by contracts, each generator had an incentive to increase its output. On the other hand, their behavior was approximately consistent with static Nash equilibrium behavior if they ignored their contracts.

It is not surprising that there was a change in behavior in late 1996, leading to generators exercising more market power, because the generators' April 1994 undertaking to keep prices low expired in April 1996 and the divestiture of capacity, which was also part of the undertaking, was completed in July 1996. As demand-weighted prices were within 1% of the cap in both 1994/95 and 1995/96 it is likely that the undertaking placed a binding constraint on NP and PG's bidding which prevented them from exercising market power.[26]

The interesting question is why NP and PG's behavior after 1996 was not consistent with static

[25] Competition Commission (2001), p. 155, reported that, by late 1990s, it was a "formidable task" for generators to predict transmission constraints.

[26] OFFER (1998a), pp. 46-47.

Nash equilibrium behavior given their contracts. There are two plausible interpretations. The first is that the generators were able to tacitly collude to raise prices above the levels possible in a static oligopoly model. Armstrong et al. (1994), p. 304, identified that daily repeated bidding, inelastic and predictable aggregate demand and the availability of information on costs made the Pool almost ideal for tacit collusion. While the market was less concentrated by the late-1990s capacity constraints meant that a small number of generators acting together had potentially great power over prices. For example, even in the first quarter of 2000, generators other than NP and PG had insufficient available capacity to meet demand in 2,500 out of 4,356 half-hour periods thereby leaving NP and PG with inelastic residual demand. If NP and PG were tacitly colluding to increase their current profits then their actual output should have been no less than their joint profit-maximizing output. In Table 5 I estimate the output which would have maximized their joint profits by considering proportional changes to the bids of both generators. Consistent with tacit collusion under the assumption of 70% contract cover, I find that their actual combined output was significantly higher than their joint profit-maximizing output until March 2000, with no significant difference after April 2000.

An alternative explanation, which does not preclude tacit collusion, is that while the generators may have taken their *current* contracts as given they exercised market power because this increased the prices they could achieve in negotiations for *future* contracts. OFGEM (1998b), p. 21, suggests that electricity supply companies believed that this explained generators' bidding behavior, although it requires that supply companies had adaptive expectations about future prices. If generators attached the same weight to profits from current and future contracts then this explanation can also potentially explain why generators' bids after 1996 were approximately consistent with static profit maximization ignoring contracts, although it would not explain why PG appears to have had an output which was too low after October 1999.

Under either explanation it may well have been easier for the generators to exercise market power in the late-1990s because, with falling fuel prices, average Pool prices did not need to be any higher than they were in the early- or mid-1990s. This made it harder for the regulator to intervene. In particular, OFGEM was unable to convince the Competition Commission in 2001 that market power had not been substantially reduced by the changes in market structure because real electricity prices had fallen since 1994.[27]

5 Conclusion

Generators exercised increasing market power in the Pool after 1996 when their bidding behavior was inconsistent with static oligopoly models which assume that each generator maximizes its current profits taking the bids of other generators and its financial contracts as given. Their behavior was consistent with tacit collusion or with them increasing Pool prices to raise prices in future contracts. Generators exercised less market power in 1995 and 1996, consistent with their April 1994 undertaking to keep prices low placing a binding constraint on their behavior.

I would like to highlight two implications of the results. First, widely-used static oligopoly models may underpredict the potential for market power in electricity markets because generators may well be able to tacitly collude. This suggests that markets should be designed in ways which make collusion harder to sustain. For example, Fabra (2003) suggests that electricity markets using discriminatory price auctions, like NETA, may be less susceptible to collusion than uniform price auctions, like the Pool. Second, generators exercised significant market power even when market concentration was relatively low. This suggests that reducing market concentration to levels which are considered moderately concentrated or unconcentrated in other industries is not always a sufficient solution to market power problems in electricity markets.

[27] Competition Commission (2001), Summary and Chapter 7.

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A Data

A.1 Pool Data (Prices, Quantities and Generator Bids)

Data on Pool prices, aggregate quantities, unit bids and unit availability from January 1 1995 to September 30 2000 was purchased from ESIS Limited. The price data contains information on realized prices (SMP, PPP and PSP), forecast demand and the identity of the marginal unit whose bid determined the SMP. For the SMP, I use the "Day Ahead SMP" determined when GOAL produces the unconstrained schedule. The correlation of this series with the "ex-post SMP" used for settlement is 0.999. I use the ex-post PPP and PSP as these prices were intended to reflect actual unit availabilities rather than availabilities declared day ahead. I use the Total Gross System Demand forecast (TGSD), which was used in GOAL, to measure demand. This included expected off-peak demand from pumped storage units and energy required to make up for transmission losses (Electricity Pool (1999), p. 27). Generator bid data contains the price elements of the bid (start-up, no load, 3 incremental prices) which remained the same over the day and unit availability for each half-hour period as declared day ahead (the Pool's XA variable). The bid data also identifies the ownership of each unit. I make one significant change to this data, changing the date at which NP sold Drax to December 1 1999. In July 1999 NP transferred Drax to a wholly-owned subsidiary which was sold to AES on December 1 1999 once the sale had been given regulatory approval (Competition Commission (2001), p. 101).

A.2 Unit Marginal Cost

I calculate marginal costs for coal, CCGT, oil and OCGT units by dividing an estimate of the fuel cost per MWh of energy by an estimate of the unit's efficiency. Unit fuel types are taken from NGC's *Seven Year Statements*. For coal and oil units I follow Wolfram (1998 and 1999) in using the efficiency estimates of Green and Newbery (1992) and Rainbow et al. (1993), using Rainbow's estimates where these are significantly higher. Coal unit efficiencies, for units operating in 1995, varied from 32.5% to

38.2%. I assume that Fifoots Point, a small coal plant which opened in 2000, had an efficiency of 35%. For CCGT units, I used OXERA's *UtilityView* database to collect plant construction dates along with some efficiency estimates. I give units the average efficiency of plants constructed in that year. I assume that OCGT units had an efficiency of 20%, consistent with Green and Newbery (1992). I take coal, natural gas, gas oil and oil input prices from the Department of Trade and Industry's (DTi) quarterly series for the "Average Prices of Fuels Purchased By Major Power Producers" (Table 3.2.1 in DTi's Energy Prices report, www.dti.gov.uk/energy/inform/energy_prices/section3.shtml). I also calculate results using fuel prices from commodity markets. These series are Datastream's daily Heavy Fuel Oil 3.5% CIF NW Europe price series (OILHFOL), Datastream's daily IPE (London) Natural Gas 1 Month Forward price series (NATBGAS) from February 1997, Datastream's daily Gas Oil -EEC CIF NW Europe price series (OILGASO) and *International Financial Statistics*'s weekly Australian coal price series.[28]

As pumped storage plants use electricity in off-peak hours I use the average PSP for the period from midnight to 5am the next morning as the input price and, consistent with Green and Newbery (1992), I assume unit efficiencies of 66%. Assumptions for other fuel types are discussed in the text.

A.3 Summary Statistics

Table A1 presents summary statistics for the main variables used in the analysis. The marginal costs of CCGT units are similar to the marginal costs of coal units when I calculate costs using average fuel prices paid because many CCGT operators signed long-term fuel contracts at relatively high prices in the early-1990s. These contracts frequently had "take-or-pay" provisions so that, at least when the price of electricity was high relative to the resale price of gas, CCGT units tended to operate on baseload. My estimates of marginal costs for coal units in January 2000 range from £10.80/MWh to £12.80/MWh which is broadly consistent with AES's estimate of £11.00/MWh to £14.00/MWh in

[28] I use the DTi series for natural gas prices prior to February 1997.

Winter 2000 (Competition Commission (2001), p. 130).

B Alternative Estimates of Market Power 1995-2000

This Appendix describes an alternative approach to calculating the competitive benchmark price used to calculate the Lerner index. In particular, this approach estimates which unit is marginal based on marginal costs and assumptions about competitive unit availability in a similar way to Wolfram (1999), Borenstein et al. (2002) and Joskow and Kahn (2002). Available units are ordered by their marginal costs and the marginal unit is identified as the highest cost unit required to meet demand. The competitive benchmark price is the marginal cost of this unit. The results are similar to those in Section 3.

Demand is the Pool's price-inelastic forecast of the demand in a half-hour period. I make the same assumptions on coal, oil, CCGT, OCGT and pumped storage costs as in Section 3. I assume that demand-side bidders, EdF and the Scottish generators and owners of cogeneration units bid competitively and estimate their marginal costs from their bids.[29] I assume that nuclear units have lower marginal costs than any other unit and, as demand was always greater than total nuclear capacity, this assumption removes the need to estimate the marginal costs of nuclear units.

I made two alternative assumptions on competitive unit availability. The first is that generators make competitive availability decisions so that I can use actual availability.[30] I measure availability using the day-ahead declarations of available capacity for each half-hour period. Table A2 columns (1)-(3) show the results for assumptions on fuel costs identical to those in columns (1), (3) and (5) in

[29] To be precise, I estimate a unit's marginal cost as $\frac{NoLoad}{Available\ Capacity(MW)} + Increment1$ which is the "Table A price" of a unit with a single increment. All interconnector and demand side bids have only one increment. I include the no load cost because many of these units bid zero incremental prices and the SMP is calculated to include the no load price in most half-hour periods.

[30] There are two exceptions to taking availability as given. I assume that each pumped storage unit is only available at 66% of its declared availability because some pumped storage capacity is always kept in reserve to meet unexpected demand fluctuations. I also assume that units entering production for the first time (primarily CCGT units) can only operate on 50% of their declared availability for their first 180 days of production reflecting the fact that plant output can be variable during commissioning. Neither of these assumptions has a significant impact on the results.

Table 1. There are some differences between the tables. In particular, in Table A2 the average Lerner index in early 1995 is even more negative indicating that the SMP-setting unit tended to have lower costs than the unit which I estimate was marginal based on marginal costs. The index is highest in 1997/98 and changes relatively little from 1997 to 2000.[31]

Of course, generators with market power may not have made competitive availability decisions so I also consider an alternative set of assumptions. I assume that demand-side bidders, EdF and the Scottish generators and owners of cogeneration units acted competitively so I still use their actual availability. For other units, I measure the unit's capacity by its highest observed availability.[32] I assume that with competitive availability decisions a unit would have been available with a probability that is the same across all units within a month and that is independent across units. This probability varies linearly with demand each year from 0.8 in the lowest demand month to 0.9 in the highest demand month. This is similar to Evans and Green's (2003) assumption for fossil units. For each half-hour period I draw random numbers to simulate which units are available and then rank these units by marginal cost to identify the marginal unit and to calculate the Lerner index. I take the average Lerner index from 5 simulations for each half-hour period to allow for any convexities in the aggregate supply curve. Table A2 columns (4)-(6) show the results for assumptions on fuel costs identical to those in columns (1), (3) and (5) in Table 1. The Lerner indices are higher than in columns (1)-(3) of Table A2 because actual availability is lower on average than the assumed competitive availability particularly after April 1998. The time series pattern of the Lerner index is the same as before, with the highest values in 1998/99 and the index changes little between 1997 and 2000.

[31] The Lerner index calculated using commodity prices falls quite dramatically after April 2000 because of a large increase in world natural gas prices, increasing the estimated marginal costs of CCGT units. However, as coal plants still set the SMP for the vast majority of periods and the increase in world coal prices was smaller, the index in Table 1, column (3) falls by a much smaller amount.

[32] As before, I reduce available capacity by 33% for pumped storage units and 50% for new units. I assume that new units have zero capacity prior to the day on which they first declare capacity available and that units which are closed have zero capacity after the day on which they are last available.

C Algorithm for Scheduling Output and Setting Prices

This Appendix describes my algorithm for scheduling production given a set of generator bids and unit availabilities. The MATLAB code is available on request. I apply the exact formulae used by the Pool, found in Section 12 of Electricity Pool (1999), to the estimated production schedule to calculate the SMP for each half-hour period. I do not have data on the technical and inflexibility parameters submitted for each unit so I make some plausible assumptions on how different types of unit can operate and include these as constraints in my algorithm.

Section 8 of Electricity Pool (1999) describes GOAL, the algorithm used by the Pool. GOAL's first step was to create a "Lagrangian Relaxation and Dynamic Programming" problem to produce a feasible unconstrained production schedule and then a linear programming problem to produce a least cost schedule. The algorithm then attempted to reduce costs by considering simple changes to the schedule such as keeping a unit on if it was scheduled to operate on-off-on. A Genset Price for each unit was calculated for each period, and it was affected by the unit's output in other periods because no load and start-up prices were spread across a unit's production run. The Genset Price of a unit with more than one increment to its bid could therefore be reduced by either changing its output in the current period or by increasing its output in other periods. The SMP was the highest Genset Price of a scheduled unit.

It is not feasible to solve dynamic and linear programming problems for a generator's actual and alternative bids. My algorithm uses the following method:[33]

1. (i) reduce the available capacity of new units by 50% during the first 180 days that they are available (otherwise I predict that these units produce too much) and (ii) reduce the available capacity of pumped storage units by 33% to reflect the fact that pumped storage capacity was kept in reserve to deal with unanticipated variation in demand;

[33] Figure 3(a) shows that for most of the sample period I tend to underpredict average prices which suggests that any problems in my algorithm do not come from a failure to minimize costs effectively.

2. assume that (i) nuclear units which are available during all periods throughout the day and (ii) non-coal units which are available but have zero prices for every element of their bids produce at their capacity in every period. If a nuclear unit is only available in some periods, which is rare, I assume that it does not operate in any period;

3. for each half-hour period during the schedule day (5am to 5am) create a merit order by ranking each increment of available capacity.[34] For Table A periods, the order is based on Genset Table A prices (GAP) for the increments, as calculated by GOAL. These prices are functions of the incremental energy price and the no load price for the increment.[35] For Table B periods, I use the maximum of the GAP and the incremental price. Only incremental prices are used to calculate the SMP in Table B periods but, as no load costs are carried over to adjacent Table A periods, some account needs to be taken of these costs in determining Table B production if no load prices are high. For peaking units (OCGT or demand-side bidders) I also include the start-up price in calculating the merit order reflecting the fact that these units typically only operate for a small number of periods at low output so that start-up costs can have a large proportional effect on prices. I set the price for pumped storage units at the maximum of the price calculated and £30/MWh in order to ensure they are not scheduled at night unless prices are high (in practice, pumped storage units tend to be unavailable in these hours);

4. create an initial output schedule using the cheapest increments in this merit order to meet forecast demand;

5. re-schedule production in order to meet the following 4 constraints on how plants of different fuel types can operate: (i) a pumped storage unit cannot operate for more than 20 half-hour

[34] GOAL actually schedules production over several more hours than the schedule day. However, Figures 3(b) and (c) show that I predict prices well at the beginning and end of the schedule day suggesting that not considering these additional hours does not create a significant problem.

[35] For the first increment the no load price used is the one declared in the bid. For higher increments the no load price is a function of the no load price and the incremental prices. For example, for the second increment the no load price is $\mathit{No\ Load} + (\mathit{Increment}1 - \mathit{Increment}2) * \mathit{Elbow}1$ where $\mathit{Elbow}1$ is the highest output for which the first incremental price applies.

periods in the day (if it does, switch it off in the periods with the lowest prices), (ii) a large coal or CCGT unit cannot operate for less than 4 periods in the day (if it does, switch it off), (iii) a large coal or CCGT unit cannot be temporarily off during the day if operating for more than 4 periods in total (if it is, turn it on to operate at its efficient level of output)[36], (iv) a unit cannot change its production by more than a certain amount between periods. The amount varies with the fuel type: 400 MW for oil units, 300 MW for large coal, CCGT and interconnector units, 200 MW for other coal units and no constraint on other units.[37] To meet the constraint on changing output, I increase the unit's production in the half-hour period with lower production but if this is inconsistent with its availability I reduce its production in the higher production period. I iterate this rescheduling procedure until the constraints are satisfied. This may leave too much or too little scheduled production. If there is too little production, additional capacity is scheduled from the merit order making sure that constraints are not violated (if they are, a higher price unit is scheduled). If there is too much production, the production of all units is reduced proportionally excluding any units for which constraints would be violated.

6. electricity prices are calculated using the new schedule and the total cost of production is calculated as the total purchase price. I then consider changes to the schedule to see if they will reduce costs defined in this way. For each of the 20 periods with the highest prices in turn, I examine how the following 9 changes to the production schedule of the highest priced unit change costs without violating constraints: (i) increase the unit's production in Table A periods of its production run to its efficient production level; (ii) keep the unit on, at its efficient production level, during an earlier sequence of periods when it is temporarily turned off; (iii) same as (ii) but for a later sequence of periods when it is temporarily off; (iv) increase the unit's production

[36] A unit's efficient level production, known as the Table A Capacity (TAC), is the output level which minimizes its per MWh costs based on incremental and no load prices.

[37] Apart from pumped storage units, which are designed to be flexible, other non-nuclear units are relatively small in size. These assumptions make smaller coal units more flexible as a proportion of their capacity than large coal units. By the late 1990s smaller coal units only tended to operate during the middle of the day and they provided variation in output as demand varied (see NGC's 2003 *Seven Year Statement*, Figure 2-5).

to the production level in the period in question during other periods in its production run; (v) if the unit switches on, turn it on one period earlier; (vi) if the unit switches off, turn it off one period later; reduce the unit's production (either to a lower increment or by turning it off) and rescheduling the production to (vii) new units (never previously scheduled) and (viii) any units including those previously scheduled; and (ix) switch the unit's production during its entire production run to another single unit (which may already have some production scheduled). If one of these changes reduces costs then this change is implemented and the next highest priced period is examined. This process is iterated, and prices recalculated, until no more cost reducing changes are found.

This provides the final schedule which, as in GOAL, is used to calculate the SMP.

Figure 1(a): Generator Shares of Capacity January 1995 - September 2000

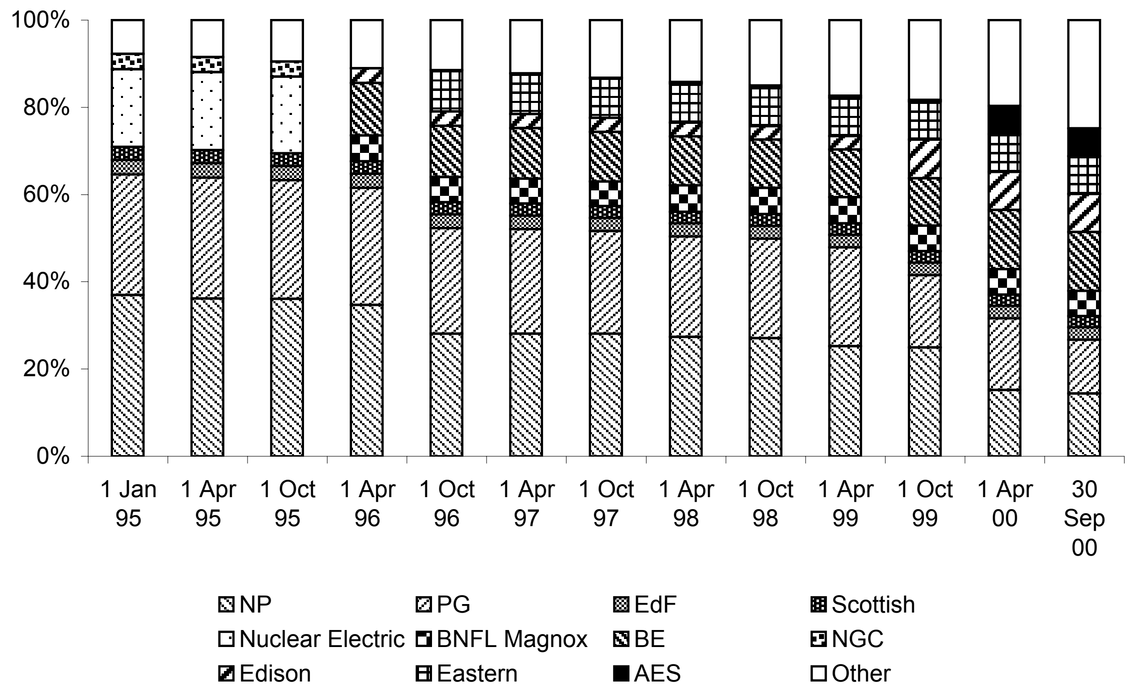

Figure 1(b): Ownership of Unit Setting SMP January 1995-September 2000

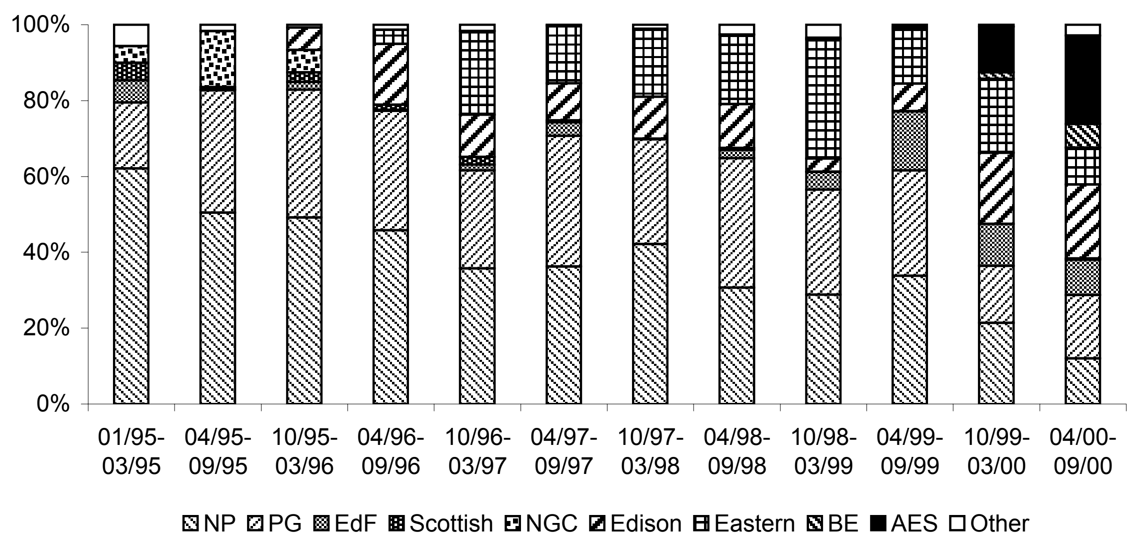

Figure 2: Monthly Average Prices and Lerner Indices

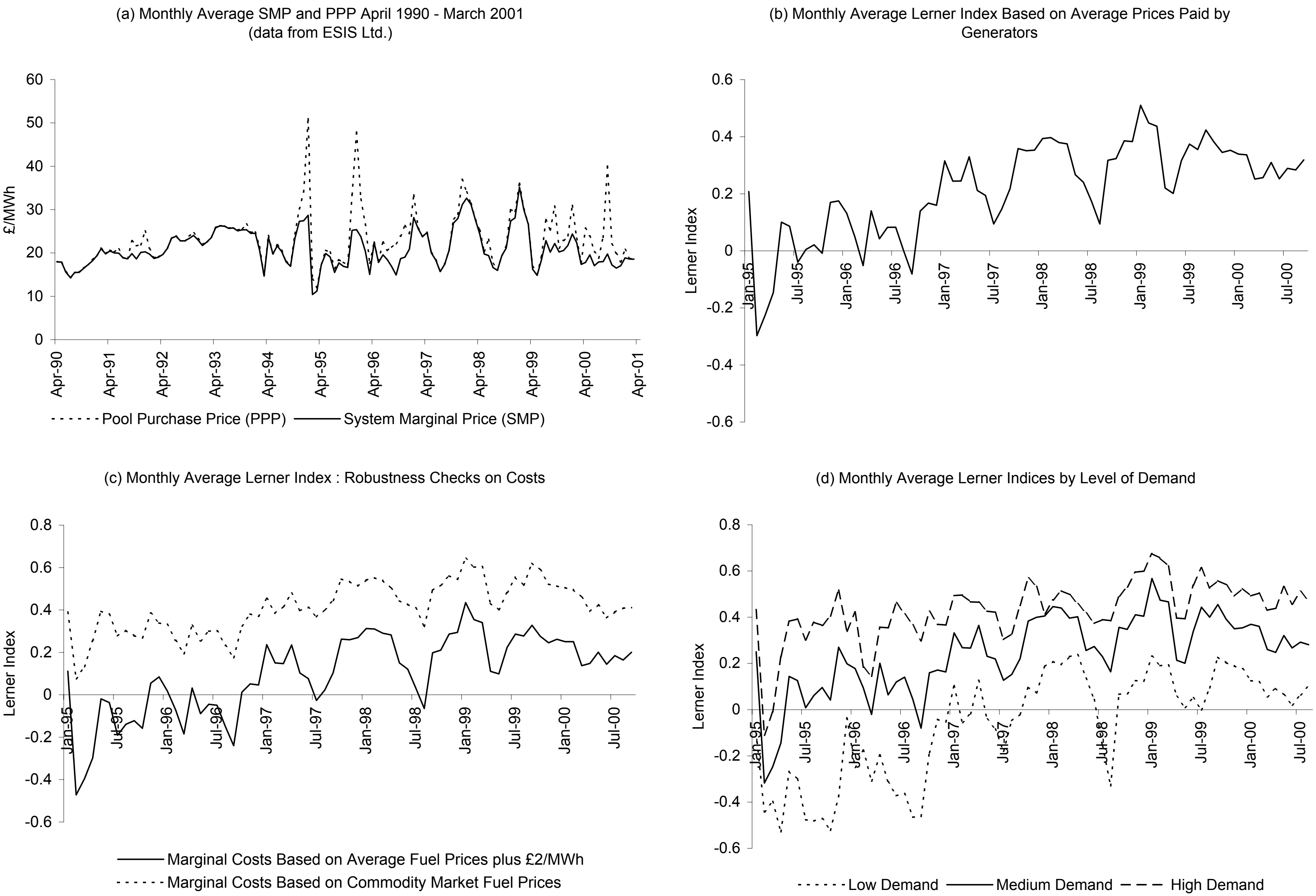

Figure 3(a): Performance of the Scheduling/Price-Setting Algorithm: Weekly Average SMP

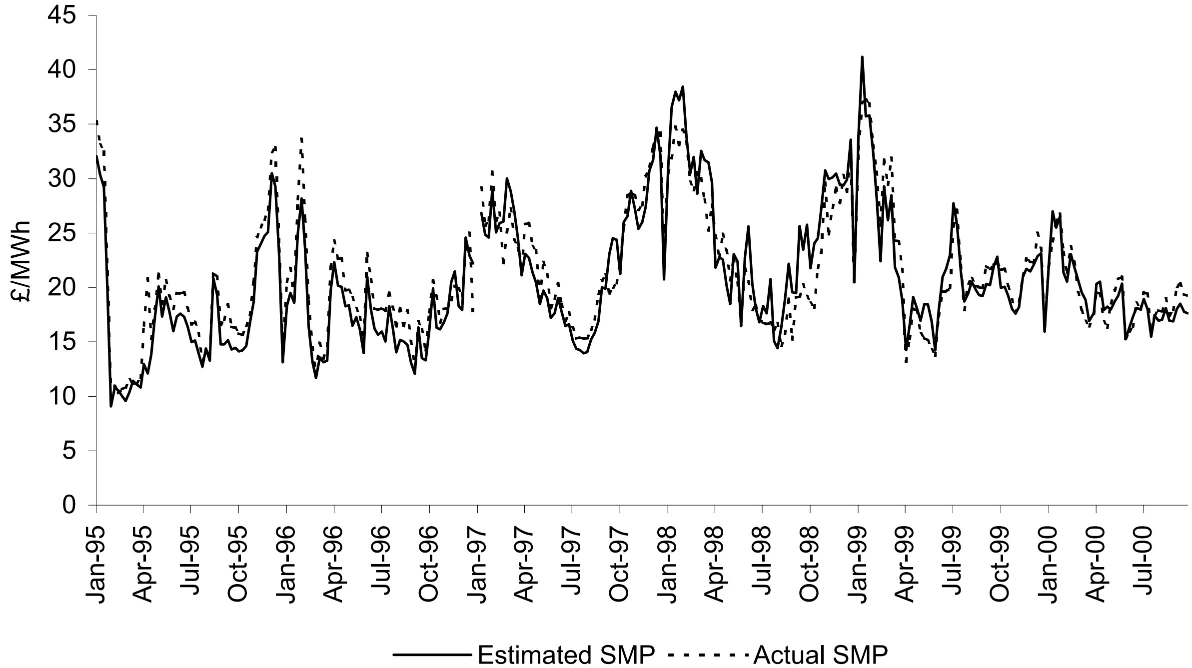

Figure 3(b): Performance of the Scheduling/Price Setting Algorithm: Errors in Predicting Prices Over Each Day

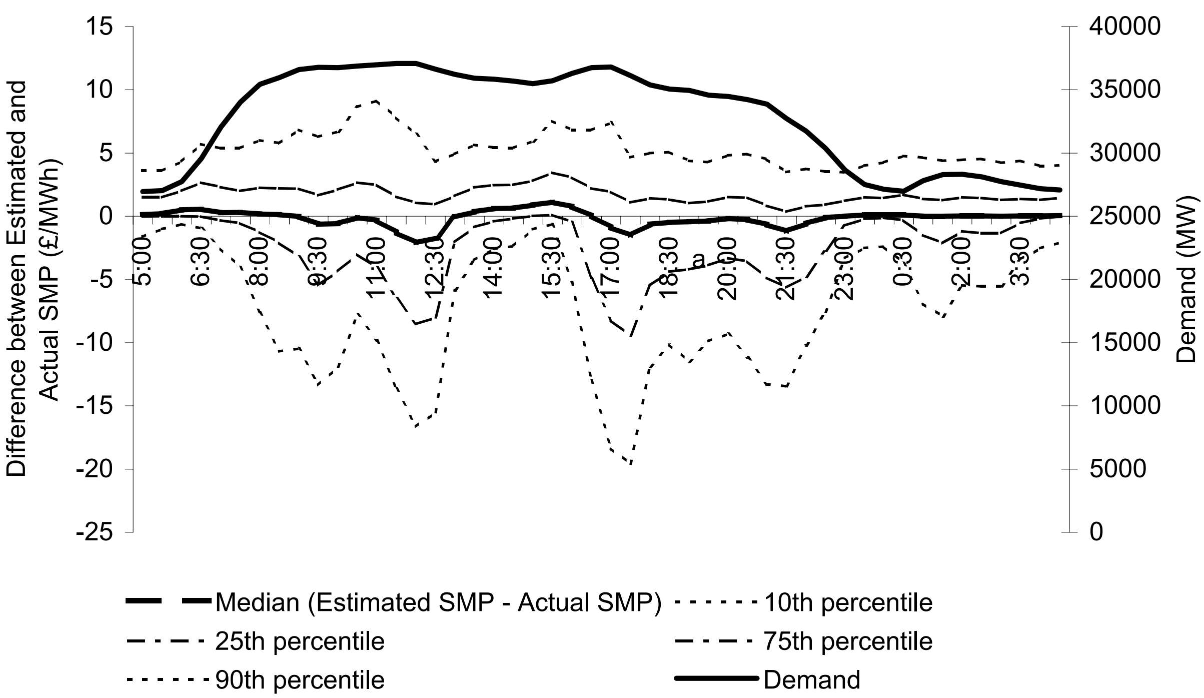

Figure 3(c): Performance of the Scheduling/Price Setting Algorithm: Performance over the Day - Weekends

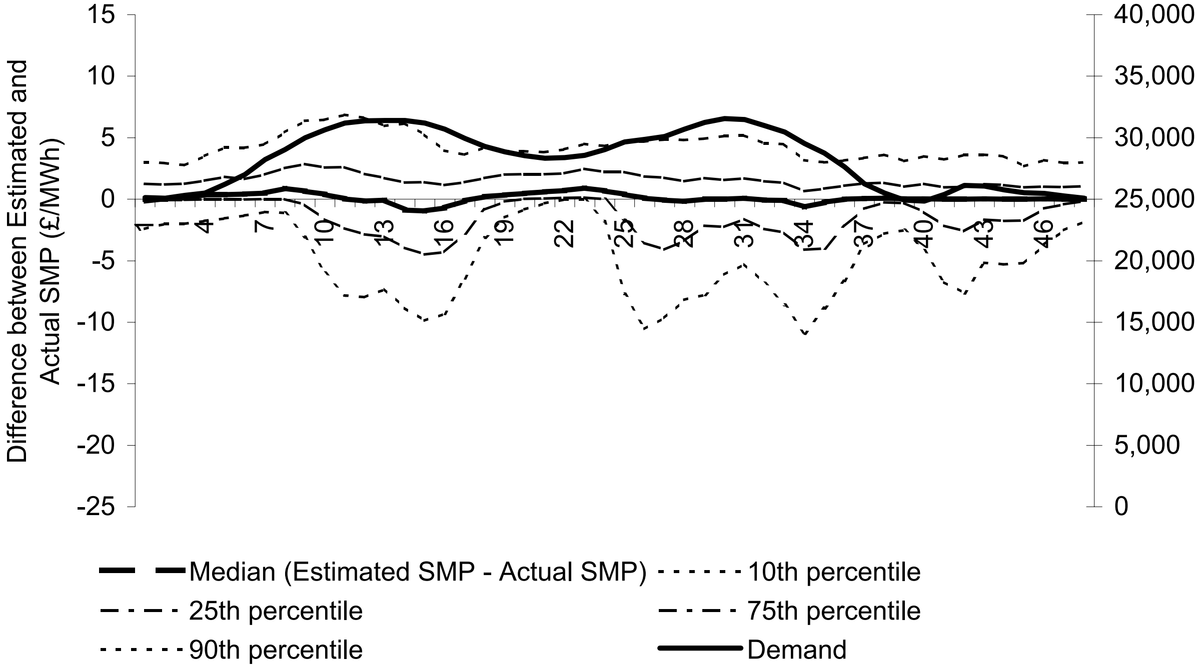

Figure 3(d): Performance of Scheduling/Price Setting Algorithm: Quantity Produced by Power Stations 1996/97

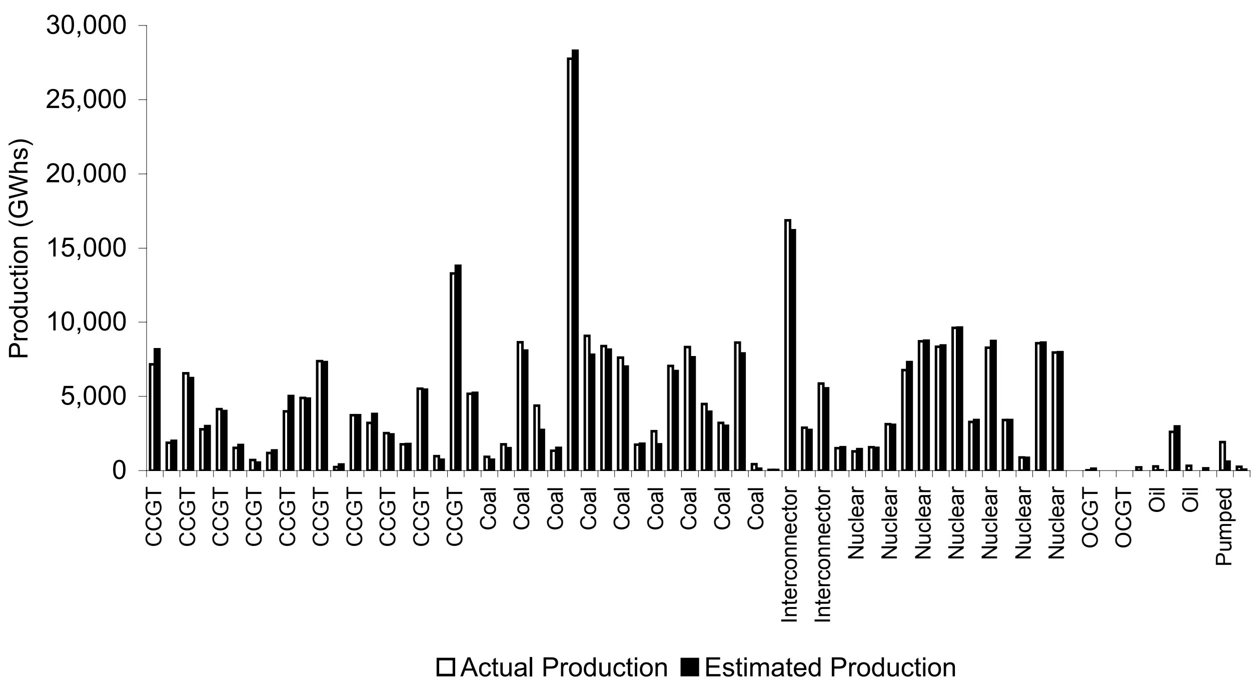

Table 1: Average Lerner Indices Based on the Unit Setting the SMP

Dates	Number of Half-Hour Periods	(1) Average Fuel Prices	(2) Wolfram Months Average Fuel Prices	(3) Commodity Fuel Prices	(4) Average Fuel Prices + £2/MWh	(5) Average Fuel Prices + £0-2/MWh	(6) Average Fuel Prices Coal Units Only
01/92-03/93			0.241 (0.129)				
04/93-03/94			0.259 (0.228)				
04/94-11/94			0.208 (0.416)				
01/95-03/95	4,318	-0.099 (0.426)	-0.099 (0.426)	0.204 (0.317)	-0.245 (0.496)	-0.102 (0.428)	-0.145 (0.428)
04/95-03/96	17,566	0.041 (0.399)	0.019 (0.408)	0.305 (0.286)	-0.088 (0.457)	0.025 (0.406)	0.003 (0.399)
04/96-03/97	17,517	0.128 (0.370)	0.199 (0.363)	0.327 (0.310)	0.008 (0.419)	0.092 (0.383)	0.122 (0.354)
04/97-03/98	17,518	0.285 (0.307)	0.323 (0.324)	0.477 (0.260)	0.184 (0.344)	0.237 (0.323)	0.307 (0.285)
04/98-03/99	17,508	0.329 (0.352)	0.387 (0.355)	0.505 (0.273)	0.219 (0.406)	0.258 (0.386)	0.364 (0.312)
04/99-03/00	17,562	0.325 (0.269)	0.311 (0.303)	0.507 (0.257)	0.229 (0.291)	0.245 (0.286)	0.386 (0.204)
04/00-09/00	8,732	0.285 (0.229)	0.273 (0.227)	0.398 (0.227)	0.174 (0.255)	0.178 (0.254)	0.310 (0.217)

Notes:

1. Half-hour periods dropped if SMP is less than 1, the marginal unit is not identified or the period is in the last day of the data.
2. Column (2) numbers for 1992-94 from Wolfram (1999), Table 1.
3. Standard deviations in parentheses.

Table 2: Comparison of Estimated Generator Wednesday Output With Actual Bids and Bids Estimated to Maximize Profits Assuming that Generators Have No Financial Hedging Contracts

	Number of Days	NP Average Capacity Operating in Half-Hour Period (MW) Actual bids	π-maximizing bids	p-value difference	PG Average Capacity Operating in Half-Hour Period (MW) Actual bids	π-maximizing bids	p-value difference
Jan 95 - Mar 95	13	13,525 (1,047)	11,768 (977)	0.0000	11,298 (621)	9,541 (776)	0.0000
Apr 95 - Sept 95	26	9,632 (1,109)	7,256 (1,265)	0.0000	6,973 (900)	5,701 (973)	0.0000
Oct 95 - Mar 96	26	12,165 (1,700)	10,011 (1,506)	0.0000	9,416 (1,356)	8,592 (1,915)	0.0016
Apr 96 - Sept 96	26	8,243 (1,059)	6,720 (1,378)	0.0000	7,149 (951)	5,709 (1,102)	0.0000
Oct 96 - Mar 97	26	7,991 (837)	7,167 (1,581)	0.0035	7,928 (712)	7,242 (1,288)	0.0238
Apr 97 - Sept 97	26	6,363 (722)	5,347 (1,634)	0.0084	5,835 (739)	5,543 (1,858)	0.3881
Oct 97 - Mar 98	25	7,673 (1,117)	8,143 (1,718)	0.1635	7,081 (781)	8,257 (1,459)	0.0011
Apr 98 - Sept 98	27	7,549 (809)	6,827 (1,914)	0.0598	5,998 (769)	6,009 (1,976)	0.7526
Oct 98 - Mar 99	26	7,058 (601)	7,079 (1,279)	0.9250	6,145 (798)	6,297 (1,200)	0.4267
Apr 99 - Sept 99	26	5,467 (676)	5,432 (1,301)	0.9126	4,894 (1,075)	5,120 (1,009)	0.4603
Oct 99 - Mar 00	26	5,613 (1,388)	5,910 (1,484)	0.3171	4,943 (603)	5,923 (1,095)	0.0001
Apr 00 - Sept 00	25	3,608 (806)	3,828 (730)	0.0316	3,742 (654)	4,144 (784)	0.0202

<u>Note:</u>
1. Standard deviations in parentheses.
2. p-value from a two-sided t-test that output using actual bids is, on average, equal to output using profit-maximizing bids.

Table 3: Comparison of Estimated Generator Wednesday Output With Actual Bids and Bids Estimated to Maximize Profits Assuming that Generators Have Financial Hedging Contracts for 70% of their Actual Output

(a) Fuel costs based on average prices paid by generators

	Number of	NP Average Capacity Operating in Half-Hour Period (MW)			PG Average Capacity Operating in Half-Hour Period (MW)		
	Days	Actual Bids	π-maximizing bids	p-value difference	Actual Bids	π-maximizing bids	p-value difference
Jan 95 - Mar 95	13	13,525 (1,047)	12,004 (1,254)	0.0000	11,298 (621)	10,455 (1,713)	0.1301
Apr 95 - Sept 95	26	9,632 (1,109)	8,263 (1,061)	0.0000	6,973 (900)	6,397 (1,237)	0.0005
Oct 95 - Mar 96	26	12,165 (1,700)	11,317 (2,358)	0.0040	9,416 (1,356)	9,672 (1,903)	0.3103
Apr 96 - Sept 96	26	8,243 (1,059)	7,422 (1,707)	0.0008	7,149 (951)	6,849 (1,167)	0.1256
Oct 96 - Mar 97	26	7,991 (837)	8,979 (1,663)	0.0002	7,928 (712)	8,956 (1,396)	0.0005
Apr 97 - Sept 97	26	6,363 (722)	7,733 (1,059)	0.0000	5,835 (739)	6,969 (1,119)	0.0000
Oct 97 - Mar 98	25	7,673 (1,117)	9,664 (1,161)	0.0000	7,081 (781)	9,418 (1,258)	0.0000
Apr 98 - Sept 98	27	7,549 (809)	8,746 (1,510)	0.0000	5,998 (769)	7,251 (1,283)	0.0000
Oct 98 - Mar 99	26	7,058 (601)	8,218 (1,105)	0.0000	6,145 (798)	7,517 (813)	0.0000
Apr 99 - Sept 99	26	5,467 (676)	7,055 (809)	0.0000	4,894 (1,075)	6,501 (1,111)	0.0000
Oct 99 - Mar 00	26	5,613 (1,388)	7,082 (1,485)	0.0000	4,943 (603)	6,648 (681)	0.0000
Apr 00 - Sept 00	25	3,608 (806)	4,097 (683)	0.0000	3,742 (654)	5,494 (978)	0.0000

(b) Fuel costs based on average prices paid by generators plus £2/MWh

	Number of	NP Average Capacity Operating in Half-Hour Period (MW)			PG Average Capacity Operating in Half-Hour Period (MW)		
	Days	Actual Bids	π-maximizing bids	p-value difference	Actual Bids	π-maximizing bids	p-value difference
Jan 95 - Mar 95	13	13,525 (1,047)	11,951 (1,157)	0.0000	11,298 (621)	10,455 (1,713)	0.1301
Apr 95 - Sept 95	26	9,632 (1,109)	7,733 (1,184)	0.0000	6,973 (900)	6,164 (1,132)	0.0000
Oct 95 - Mar 96	26	12,165 (1,700)	11,192 (2,260)	0.0000	9,416 (1,356)	9,460 (2,068)	0.8613
Apr 96 - Sept 96	26	8,243 (1,059)	7,013 (1,391)	0.0000	7,149 (951)	6,738 (1,198)	0.0331
Oct 96 - Mar 97	26	7,991 (837)	8,823 (1,536)	0.0005	7,928 (712)	8,731 (1,456)	0.0032
Apr 97 - Sept 97	26	6,363 (722)	7,140 (1,336)	0.0056	5,835 (739)	6,752 (1,118)	0.0000
Oct 97 - Mar 98	25	7,673 (1,117)	9,549 (1,298)	0.0000	7,081 (781)	9,285 (1,260)	0.0000
Apr 98 - Sept 98	27	7,549 (809)	8,470 (1,587)	0.0001	5,998 (769)	7,099 (1,324)	0.0000
Oct 98 - Mar 99	26	7,058 (601)	8,149 (1,144)	0.0000	6,145 (798)	7,293 (929)	0.0000
Apr 99 - Sept 99	26	5,467 (676)	6,568 (1,116)	0.0000	4,894 (1,075)	6,182 (1,189)	0.0000
Oct 99 - Mar 00	26	5,613 (1,388)	6,767 (1,582)	0.0000	4,943 (603)	6,397 (906)	0.0000
Apr 00 - Sept 00	25	3,608 (806)	3,912 (746)	0.0011	3,742 (654)	4,636 (776)	0.0000

(c) Saturdays, fuel costs based on average prices paid by generators

	Number of	NP Average Capacity Operating in Half-Hour Period (MW)			PG Average Capacity Operating in Half-Hour Period (MW)		
	Days	Actual Bids	π-maximizing bids	p-value difference	Actual Bids	π-maximizing bids	p-value difference
Jan 95 - Mar 95	11	10,990 (790)	9,822 (627)	0.0000	8,892 (720)	7,378 (1,343)	0.0014
Apr 95 - Sept 95	27	6,669 (1221)	5,700 (1,563)	0.0000	5,117 (868)	4,672 (1,272)	0.0285
Oct 95 - Mar 96	25	9,322 (1561)	7,975 (1,725)	0.0000	7,445 (1,174)	6,636 (1,437)	0.0000
Apr 96 - Sept 96	26	6,060 (965)	5,477 (1,101)	0.0002	4,994 (946)	4,461 (975)	0.0000
Oct 96 - Mar 97	25	6,689 (1140)	7,198 (1,410)	0.0218	6,632 (1,106)	7,279 (1,345)	0.0017
Apr 97 - Sept 97	26	4,840 (737)	5,227 (1,125)	0.0182	4,249 (809)	4,857 (1,103)	0.0001
Oct 97 - Mar 98	24	6,241 (943)	8,147 (1,346)	0.0000	6,088 (686)	8,145 (1,171)	0.0000
Apr 98 - Sept 98	26	5,469 (757)	6,255 (1,279)	0.0003	4,544 (762)	5,395 (781)	0.0000
Oct 98 - Mar 99	25	5,730 (673)	7,124 (989)	0.0000	5,129 (746)	6,288 (960)	0.0000
Apr 99 - Sept 99	26	4,026 (734)	4,886 (1,000)	0.0000	3,662 (725)	4,641 (796)	0.0000
Oct 99 - Mar 00	25	4,478 (1227)	5,909 (1,502)	0.0000	3,999 (582)	5,410 (640)	0.0000
Apr 00 - Sept 00	25	2,615 (599)	3,048 (754)	0.0000	2,678 (468)	3,730 (723)	0.0000

Notes:

1. Standard deviations in parentheses.

2. p-value from a two-sided t-test that output using actual bids is, on average, equal to output using profit-maximizing bids.

Table 4: Average Number of Units Operating and Number of Unit Start-Ups Per Day For Actual and Profit-Maximizing Bids Assuming that 70% of Generators' Actual Output is Covered by Financial Hedging Contracts

	National Power				**PowerGen**			
	Actual bids		π-maximizing bids		Actual bids		π-maximizing bids	
	Unit-Periods Operating	Unit Start-Ups	Unit-Periods Operating	Unit Start-Ups	Unit-Periods Operating	Unit Start-Ups	Unit-Periods Operating	Unit Start-Ups
Jan 95 - Mar 95	1,471.2 (178.5)	13.4 (9.4)	1,342.6 (185.4)	15.2 (15.4)	1,321.6 (73.6)	10.0 (4.6)	1,388.2 (90.4)	9.2 (5.6)
Apr 95 - Sept 95	1,019.6 (112.5)	17.0 (3.8)	854.4 (123.2)	17.1 (4.3)	753.8 (85.)	10.9 (3.7)	706.0 (116.)	10.6 (4.5)
Oct 95 - Mar 96	1,277.4 (196.9)	21.1 (7.3)	1,176.7 (278.7)	21.8 (8.7)	1,036.7 (151.2)	11.8 (5.3)	1,106.7 (204.9)	13.4 (8.9)
Apr 96 - Sept 96	848.7 (104.8)	13.2 (3.7)	768.7 (164.7)	15.1 (3.8)	802.2 (96.5)	8.3 (1.7)	775.8 (108.3)	8.8 (2.1)
Oct 96 - Mar 97	790.6 (107.9)	13.9 (4.9)	936.9 (186.8)	17.6 (6.5)	865.0 (74.4)	6.0 (2.6)	972.7 (130.1)	7.8 (2.9)
Apr 97 - Sept 97	599.9 (84.7)	10.6 (4.1)	791.1 (136.3)	16.9 (4.5)	648.4 (74.9)	7.2 (2.3)	766.6 (106.6)	9.4 (2.2)
Oct 97 - Mar 98	709.5 (119.7)	18.4 (4.4)	936.7 (130.4)	22.8 (4.9)	763.1 (75.4)	7.1 (2.)	994.4 (123.5)	7.7 (2.4)
Apr 98 - Sept 98	716.3 (92.9)	12.6 (3.3)	891.9 (175.)	13.6 (3.8)	679.6 (79.6)	7.9 (2.1)	796.9 (122.6)	5.7 (3.7)
Oct 98 - Mar 99	646.5 (64.2)	13.8 (4.5)	769.8 (127.1)	16.9 (5.9)	677.3 (87.2)	7.7 (2.3)	816.3 (85.4)	9.8 (3.5)
Apr 99 - Sept 99	490.1 (62.4)	7.7 (1.8)	653.0 (86.6)	8.5 (3.3)	559.2 (98.2)	6.2 (1.9)	718.5 (98.)	7.1 (3.2)
Oct 99 - Mar 00	505.8 (119.1)	7.4 (3.7)	657.0 (129.)	6.9 (3.7)	536.3 (56.7)	4.8 (1.6)	703.4 (66.5)	3.6 (1.9)
Apr 00 - Sept 00	367.7 (77.8)	4.3 (2.1)	420.0 (67.6)	2.3 (1.6)	443.9 (63.9)	4.6 (1.8)	615.4 (106.9)	3.9 (1.9)

Note:
1. Standard deviations in parentheses.

Table 5: Comparison of Estimated Wednesday Output of NP and PG Combined With Actual Bids and Bids Estimated to Maximize Joint Profits With 70% of their Actual Output Covered by Financial Hedging Contracts

		NP & PG Average Capacity Operating in Half-Hour Period (MW)		
	Days	Actual bids	Joint π-maximizing bids	p-value difference
Jan 95 - Mar 95	13	24,823 (594)	23,951 (816)	0.0000
Apr 95 - Sept 95	26	16,605 (1,874)	16,313 (1,832)	0.0000
Oct 95 - Mar 96	26	21,581 (2,776)	21,110 (2,697)	0.0000
Apr 96 - Sept 96	26	15,392 (1,848)	14,901 (1,950)	0.0000
Oct 96 - Mar 97	26	15,919 (1,374)	14,499 (1,502)	0.0000
Apr 97 - Sept 97	26	12,198 (1,179)	11,096 (1,159)	0.0000
Oct 97 - Mar 98	25	14,754 (1,756)	13,840 (1,832)	0.0000
Apr 98 - Sept 98	27	13,548 (1,229)	12,275 (1,042)	0.0000
Oct 98 - Mar 99	26	13,203 (1,151)	12,088 (1,217)	0.0000
Apr 99 - Sept 99	26	10,361 (1,485)	9,030 (1,630)	0.0000
Oct 99 - Mar 00	26	10,556 (1,779)	9,281 (1,756)	0.0039
Apr 00 - Sept 00	25	7,351 (1,318)	7,345 (1,044)	0.9748

Note:

1. Standard deviations in parentheses.
2. p-value from a two-sided t-test that output using actual bids is, on average, equal to output using profit-maximizing bids.

Table A1: Summary Statistics

	Units	Number of Observations		Mean	Std. Deviation	Min	Max
Pool Prices and Demand							
SMP	£/MWh	100,788	half-hours	21.13	13.29	0	836.16
PPP	£/MWh	100,778	half-hours	24.28	26.98	0	1108.12
PSP	£/MWh	100,778	half-hours	25.45	30.05	0	1180.52
Demand (TGSD)	MW of required capacity	100,682	half-hours	32995.97	5965.28	19,026	51,065
Unit Bids (available units only)							
Start-Up	£	381,802	unit days	5727.5	8051.19	0	99999
No Load	£	381,802	unit days	1322.35	2186.57	0	9999.99
Increment 1	£/MWh	381,802	unit days	30.58	59.83	0	999.99
Increment 2	£/MWh	381,802	unit days	38.57	59.35	0	999.99
Increment 3	£/MWh	381,802	unit days	39.13	59.3	0	999.99
Unit Availability	MW	17,581,960	unit-periods	269.35	245.25	0.02	989
Marginal Cost (available units only, based on average prices paid for input fuels by generators)							
Coal	£/MWh	102,222	unit days	12.51	1.33	10.18	15.7
CCGT	£/MWh	47,933	unit days	13.46	1.42	10.05	16.83
Oil	£/MWh	8,857	unit days	19.62	2.74	15.43	27.46
OCGT	£/MWh	73,305	unit days	45.07	12.39	23.33	90.44
Pumped Storage	£/MWh	19,510	unit days	23.18	10.59	3.74	157.25

Notes:
1. Ex-Post PPP and PSP missing for 10 half-hour periods, TGSD for 106 periods
2. Available units are units which declare capacity available in at least one half-hour period during the day.

Table A2: Average Lerner Indices Calculated By Estimating the Identity of the Marginal Unit

Dates	Availability Number of Half-Hour Periods	(1) Actual Average Fuel Prices	(2) Actual Commodity Fuel Prices	(3) Actual Average Fuel Prices + £0-2/MWh	(4) Simulated Average Fuel Prices	(5) Simulated Commodity Fuel Prices	(6) Simulated Average Fuel Prices + £0-2/MWh
01/95-03/95	4,316	-0.202 (0.500)	-0.027 (0.442)	-0.206 (0.502)	-0.223 (0.528)	-0.015 (0.469)	-0.227 (0.530)
04/95-03/96	17,564	0.049 (0.429)	0.268 (0.290)	0.031 (0.437)	0.037 (0.419)	0.285 (0.303)	0.020 (0.427)
04/96-03/97	17,180	0.144 (0.368)	0.301 (0.270)	0.107 (0.384)	0.147 (0.357)	0.328 (0.268)	0.110 (0.372)
04/97-03/98	17,516	0.305 (0.302)	0.531 (0.204)	0.256 (0.324)	0.311 (0.295)	0.536 (0.195)	0.262 (0.317)
04/98-03/99	17,506	0.278 (0.361)	0.531 (0.245)	0.204 (0.400)	0.326 (0.329)	0.549 (0.230)	0.252 (0.369)
04/99-03/00	17,560	0.272 (0.292)	0.541 (0.190)	0.175 (0.334)	0.307 (0.277)	0.555 (0.179)	0.210 (0.318)
04/00-09/00	8,674	0.274 (0.257)	0.248 (0.281)	0.151 (0.303)	0.300 (0.262)	0.431 (0.197)	0.177 (0.308)

Notes:
1. Half-hour periods dropped if SMP less than 1, TGSD missing, unit availability missing or first week of 1997 (availability data contains different unit codes) or in the last day of data.
2. Standard deviations in parentheses.