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SPOT MARKET COMPETITION IN THE UK ELECTRICITY INDUSTRY*

Nils-Henrik Mørch von der Fehr and David Harbord

At the core of the recently deregulated and privatised UK electricity industry is the wholesale spot market.[1] Before each period that the market is open, the generating companies (generators) submit minimum prices at which they are willing to supply power. On the basis of these 'offer prices', the National Grid Company, which plays a central role as coordinator and is responsible for running the transmission grid, draws up a least-cost plan of generating units ('sets') for despatch in the next period. This 'rank order', together with demand, determines which units will actually be despatched. Payments to supplying sets are based on a 'system marginal price' determined as the offer price of the marginal operating unit in every period.

The particular organisation of the electricity spot market makes standard oligopoly models inadequate as analytical tools, and we propose instead to model the market as a sealed-bid multiple-unit auction. In the first stage of the model, generators simultaneously submit offer prices at which they are willing to supply their (given) capacities. As in the UK industry, generators can submit different offer prices for each individual set, i.e. they offer step-supply schedules. Sets are then ranked according to their offer prices (i.e. a supply curve is constructed). In the final stage, demand is realised and system marginal price is determined by the intersection of demand and supply, that is by the offer price of the marginal operating unit.

It turns out that pure-strategy equilibria do not always exist in such a model. The reason is basically the same as that in standard oligopoly models of capacity-constrained price competition (Kreps and Scheinkman, 1983). Since, when demand is sufficiently large, a generator is unable to serve the whole market at the competitive price, there is an incentive to raise bids above marginal cost, and thus the competitive outcome cannot be an equilibrium. It can then be shown that for a range of demand distributions no other pure-strategy combinations constitute an equilibrium either. We believe that this result does not necessarily reflect an inadequacy of our modelling approach,

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[1] For details on the UK electricity industry, new and old, see Vickers and Yarrow (1990), Green (1991*a*) and James Capel & Co. (1990).

but rather suggests an inherent price instability in the present regulatory set up. Indeed, our empirical evidence (see Section III) would seem to confirm that experimentation and abrupt changes in pricing strategies is a feature of the new industry.

Our results cast some doubt on the relevance of the model analysed by Green and Newbery (1991) (see also Bolle, 1992 and Newbery, 1991). These authors argue that the 'step-length', i.e. the size of individual generating sets, is small enough to justify approximating the step-supply schedules by smooth (i.e. continuously differentiable) functions, thus applying the supply-function framework developed by Klemperer and Meyer (1989). As we demonstrate in Section II however, the particular types of equilibria they derive do not generalise to a model where sets are of positive size. Although theirs is a seemingly very useful contribution, it remains 'an open question whether the bidding strategies of the generators will differ significantly if they are forced to provide a step function, or whether they are allowed to provide a smooth schedule' (Green and Newbery, 1991, footnote 2, page 5).[2]

Nevertheless the most important result, inefficient pricing, turns out to be robust to alternative forms of modelling. Indeed, we find an even stronger tendency than Green and Newbery towards above marginal-cost pricing. Thus the conjecture that the Bertrand outcome is unlikely in the present institutional set-up, even if there is no collusive behaviour, seems to be strongly supported. In addition, our model suggests that high-cost sets may be bid in at lower offer prices than lower-cost sets and thus be despatched before these more efficient units. Hence despatching may be inefficient in the sense that overall economic generation costs are not minimised.

An important advantage of our framework is that it makes it possible to model explicitly the role of the grid company (the auctioneer), and then use insights from the auction literature to study the effects of different pricing rules, i.e. the rules determining the prices paid to different supplying units. In particular, in Section IV we discuss how offering to supply at marginal cost can be induced as a dominant strategy for each generator.

I. THE MODEL

There are N independent generators each having constant marginal costs, $c_n \geqslant 0$, $n = 1, 2, \ldots, N$, at production levels below capacity, while production above capacity is impossible. We let the index n rank generators according to their marginal costs, i.e. $c_n \leqslant c_{n+1}$. The total capacity of generator n is given by k_n, $n = 1, 2, \ldots, N$. The capacity of generator n consists of m_n generating units, or sets, where k_{ni} is the capacity of the ith set, $i = 1, 2, \ldots, m_n$, and $\sum_i k_{ni} = k_n$.

Before the actual opening of the market, the generators simultaneously submit offer prices for each of their sets, $p_{ni} \leqslant \bar{p}$, $i = 1, 2, \ldots, m_n$, $n = 1, 2, \ldots, N$,

[2] Green and Newbery also assume downward sloping demand curves, whereas completely inelastic demand would seem to be more appropriate for the UK industry. Bolle (1992) proves that in the latter case, no equilibrium exists in the supply-function model.

at which they are willing to supply electricity.[3] On the basis of these bids, an auctioneer draws up a ranking of units, i.e. a market supply curve is constructed. If two or more sets (of any generator) are offered at the same price, they are equally likely to be called into operation. When the market opens, demand, d, is determined as a random variable independent of price; in particular, $d \in [\underline{d}, \bar{d}] \subseteq [0, K], K \equiv \sum_{n=1}^{N} k_n$, according to some probability distribution $G(d)$. The auctioneer, by calling suppliers into operation, equates demand and supply.

Operating units, or units actually supplying output, are paid system marginal price, which is equal to the offer price of the marginal operating unit. All players are assumed to be risk neutral and hence aim to maximise their expected payoff. All aspects of the game, as well as the players' marginal costs and capacities and the probability distribution $G(d)$, are assumed to be common knowledge.

The model may be characterised as a first-price, sealed-bid, multiple-unit private-value auction with a random number of units (McAfee and McMillan, 1987; Hausch, 1986). It is 'sealed-bid' because of the simultaneous move structure, 'first-price' in the sense that the market price is determined by the marginal successful supplier, and 'private-values' because generators' unit payoff equal the difference between the market price and individual marginal costs.

II. ANALYSIS

In this section we characterise the Nash-equilibria of the model presented in Section I. Most of the discussion will centre on the duopoly case. Apart from being the relevant case for the UK electricity industry (see the discussion in Section III), explicit formulae for optimal strategies are difficult to derive in the more general oligopoly case. Hence our discussion of oligopoly in this section is in most cases limited to pointing out where and how the duopoly results generalise. We start by presenting a result on the types of pure-strategy equilibria that can occur:[4]

PROPOSITION 1. *If $c_n \neq c_m$, all m, n, in pure-strategy equilibria only one generator determines system marginal price with positive probability.*[5]

A player which owns a set which has a positive probability of becoming the marginal operating unit, will always want to increase the offer price of that set by some small amount towards the next higher bid; that does not affect the ranking, but increases payoff in the event that this is the marginal set. On the

[3] Note that firms' offer prices are constrained to be below some threshold level $\bar{p} < \infty$, since otherwise, in cases when there is a positive probability that all sets will be called into operation, expected payoffs could be made infinitely large. A natural interpretation of $\bar{p}$ is that it is a (regulated) maximum price, either officially, or as perceived by the generators (i.e. firms believe that the regulation authorities will effectuate price regulation if the price rises above $\bar{p}$). Indeed, in the UK system payments never exceed the VLL, 'Value of Lost Load' (approx. £2 per kWh).

[4] Formal proofs can be found in the working paper version (von der Fehr and Harbord, 1992*a*). See also von der Fehr (1990).

[5] If firms have identical marginal costs there may exist Bertrand-type equilibria in which more than one firms owns sets which with positive probability may become marginal.

other hand, it cannot be optimal to submit an offer price equal to or just above that of a set of another player; as long as the offer price is above marginal cost (which it will be for at least one generator), profits can be increased by undercutting the rival slightly, thereby increasing the probability of being called into operation, without significantly reducing the price received in any state. These two opposing forces destroy any candidate pure-strategy equilibrium in which two or more generators both have sets which with positive probability will become the marginal.

Proposition 1 implies that the types of pure-strategy equilibria that may exist are very restricted, and, furthermore, it rules out the existence of pure-strategy equilibria for a wide range of demand distributions. Significantly, it follows that the types of equilibria found by Green and Newbery (1991) in their model do not generalise to the case in which individual generating sets are of positive size. The reason that such equilibria exist in their supply-function framework is that when individual sets are of size zero (the cost function is continuously differentiable everywhere), the gain from undercutting any individual rival set is negligible, and thus the second part of the above argument does not apply.

Below we consider circumstances under which pure-strategy equilibria will exist, as well as presenting examples of mixed-strategy equilibria when pure-strategy equilibria do not exist. The existence, multiplicity and the type of equilibria will be seen to depend crucially on the support of the demand distribution. We will therefore distinguish between three generic cases; 'Low-Demand Periods' in which a single generator can supply the whole of demand, 'High-Demand Periods' in which both generators will be producing with probability 1, and 'Variable-Demand Periods' when there is a positive probability for both the event that a single generator can supply the whole of demand *and* the event that both generators will have to be called into operation.

II.1. *Low-demand periods*

We begin by considering the case where, with probability 1, demand is less than the capacity of the smallest generator. This corresponds to the standard Bertrand model of oligopoly and thus there is a unique equilibrium outcome in which both generators offer to supply at a price equal to the marginal cost of the least efficient generator:

PROPOSITION 2. *If* $\Pr(d < \min\{k_1, k_2\}) = 1$, *there exist pure-strategy equilibria, in all of which system marginal price equals the marginal cost of the least efficient generator,* c_2, *and only generator* 1 *produces.*

Since, with probability 1, demand can be covered by one generator, there will be competition to be despatched. In particular, a generator will always undercut its rival so long as its rival's bids are above its own marginal costs. Thus any equilibrium must have the most efficient generator (generator 1) submitting offer prices for a capacity sufficient to cover demand, at or below the marginal cost of the least efficient generator. Since in this range, generator 1's profit is increasing in its own offer price, these bids must equal c_2. We conclude that in low demand periods, system marginal price is bounded above by the marginal costs of the less efficient generator.[6]

II.2. *High-demand periods*

In this sub-section we assume that with probability 1 both generators will be called into operation, irrespective of bids. It turns out that in this case the extreme opposite to the result of the previous section holds; whereas in low-demand periods system marginal price equals the marginal cost of the least efficient generator, in high-demand periods it always equals the highest admissible price.

PROPOSITION 3. *If* $\Pr(d > \max\{k_1, k_2\}) = 1$, *all pure-strategy equilibria are given by offer-price vector pairs* (p_1, p_2) *satisfying either* $p_{1i} = \bar{p}$[7] *and* $p_{2i} \leqslant b_2$ *or* $p_{2j} = \bar{p}$ *and* $p_{1i} \leqslant b_1$, *for some* $b_n < \bar{p}$, $n = 1, 2$.

By Proposition 1, the high-bidding generator will always determine system marginal price. Therefore its payoff is increasing in its own offer prices and profit maximisation requires bidding at the highest admissible price. The low-bidding generator is indifferent between any offer price lower than that of the high-bidding generator. However, to ensure that the high-bidding generator does not deviate, the low-bidding generator has to bid low enough so that the high-bidding generator's payoff from undercutting is less than the payoff earned at equilibrium. Thus the upper bound on the low-bidding generator's offer price.[8]

In all of the equilibria characterised by Proposition 3, system marginal price equals the highest admissible price. The low-bidding generator is despatched with its full capacity while the high-bidding generator supplies the residual demand. It follows that both generators prefer equilibria in which they act as the low-bidding generator, since the received price is the same while a generator's output is greater when it is ranked first. Note that some of these equilibria involve inefficient despatching: The high-cost generator's bid may be the lowest and thus it will be despatched with its total capacity, while the low-cost generator is only despatched with part of its capacity. In such equilibria generation costs are not minimised.

II.3. *Variable-demand periods*

We turn now to the intermediate case in which there is a positive probability of either generator becoming the marginal generator, whatever their offer prices. It is clear that offer-price pairs like those in Proposition 3 cannot constitute equilibria in this case since the low-bidding generator will now

[6] A similar result can be shown to hold in the oligopoly model. If, with probability 1, demand is less than the total capacity of the n most efficient generators ($n < N$), then in any equilibrium system marginal price cannot exceed the marginal cost of the $n+1$st most efficient generator. However, as we show in Section II 3, pure-strategy equilibria will generally not exist in this model.

[7] Strictly speaking, only offer prices of sets that may become marginal need equal $\bar{p}$ in equilibrium.

[8] It is easy to see that in the oligopoly case we get a corresponding result: whenever demand is such that the highest-bidding generator determines the system marginal price with probability 1, any vector of offer prices such that the highest-pricing generator submits $\bar{p}$ while the rest bid sufficiently below this, will be an equilibrium.

always wish to increase its offer price; in doing so it thereby increases system marginal price in the event that it becomes the marginal operating generator. In fact, we have the following result:

PROPOSITION 4. *If $\bar{d}-\underline{d} > \max\{k_1, k_2\}$, where $[\underline{d}, \bar{d}]$ is the support of the demand distribution, there does not exist an equilibrium in pure strategies.*

This result follows directly from Proposition 1. Since the range of possible demands exceeds the capacity of the largest generator, it follows that for any strategy combination there is a positive probability that sets of either generator will be the marginal operating unit. We can then apply the result of Proposition 1; there cannot exist pure-strategy equilibria for which more than one generator has a positive probability of determining system marginal price.

In the remainder of this section we consider mixed-strategy equilibria for an example where for all n, $m_n = 1$, i.e. each generator owns only one set, or can submit only one price for the whole of its capacity. The analysis is considerably simplified by restricting attention to the following special case: All generators are assumed to have equal capacities normalised to 1, and demand is discrete and distributed on $\{1, 2, \ldots, N\}$ with probabilities $\pi_n = \Pr(d = n)$, $n = 1, 2, \ldots, N$, with $\Pr(d = n) \geqslant 0$ and $\sum_n \pi_n = 1$. Since the main results carry over to the more general model, for the rest of this section we concentrate on this special case.

In the duopoly model we are able to show that there exists a unique mixed-strategy equilibrium, and we can derive the explicit form of the two players' strategies (see von der Fehr and Harbord, 1992*a*). In particular, we find that the lowest price in the support of the players' strategies is strictly greater than the marginal cost of the least efficient generator, and that this lowest price is an increasing function both of the highest possible price $\bar{p}$, the probability that both generators will be operating (i.e. demand), and the marginal cost of the least efficient generator. Without loss of generality normalise c_1 to zero, and let $c_2 \equiv c$, $\Pr(d = 1) \equiv \pi$, and $\Pr(d = 2) \equiv 1-\pi$.

PROPOSITION 5. *Assume $N = 2$ and $0 < \pi < 1$. Then there exists a unique mixed-strategy Nash equilibrium in which player i plays prices $p \in [p^m, \bar{p}]$ according to the probability distribution $F_i(p)$, $i = 1, 2$. $p^m > 0$ and $F_1(p) \geqslant F_2(p)$.*

In equilibrium, players strike a balance between two opposing effects. On the one hand, a high bid results in a high system marginal price, and payoff, in the event that the generator becomes marginal. On the other hand, bidding high reduces the chance of becoming the lowest-pricing generator and thus being despatched. The latter effect is less important the smaller is π, since then it is very likely that both generators will be despatched, and thus bids are increasing in demand. In particular, it is easily demonstrated that the cases discussed in Sections II.1 and II.2 are obtained as limits when π approaches its extremes. The high-cost generator's strategy profile first-order stochastically dominates the strategy profile of the low-cost generator. Thus, the high-cost generator will generally (i.e. in expected terms) submit higher bids than the low-cost generator. We have not been able to find an algebraic expression for the probability that the high-cost generator submits a bid below that of the low-cost generator, but a lower bound can be established by considering the probability that $p_2 < p_1 - c$. For the particular example $\pi = \frac{1}{2}$, if $\bar{p}/c = 5(10)$, i.e. $\bar{p}$ is 5(10) times the marginal cost of the high-cost generator, this probability equals 12% (27%). Thus, although the typical outcome is that the high-cost generator prices above the low-cost generator, there is a potentially significant positive probability that the high-cost generator submits the lowest offer price and thus becomes the only operating generator. Therefore we may conclude that, as in the case discussed in section II.2, the regulatory rule, as it is modeled here, is not ex-post efficient.

In the oligopoly model we are able to characterise equilibria in any detail only for the case when all generators have equal marginal costs. In this case we can show that there exists a unique symmetric mixed-strategy equilibrium in which generators always play prices above marginal costs. Based on this equilibrium, we are able to shed some light on the question of how the number of suppliers in the market will affect the price structure. There are in general two different ways of analysing this. We could either think of a situation where, for a given level of demand, additional generators are introduced into the market, i.e. total capacity is increased, or a situation in which existing generators are split up into smaller units, i.e. a given total capacity is divided between a larger number of generators. If the question of primary interest is the organisation of the deregulated structure of an existing industry, the latter approach seems the most natural and is what we have considered. For the particular example $\pi_i = 1/N$, $i = 1, 2, \dots, N$, closed-form solutions for strategies can be derived and from these it follows that prices will tend to be lower on average in a more fragmented industry. The intuition for this may be explained as follows: By increasing its offer price a generator reduces the probability that it will receive a positive payoff. On the other hand, submitting a high offer price increases, in expected terms, system marginal price. The system marginal price effect, however, benefits the generator only when it happens to be the marginal generator, an event which is less likely the more generators there are in the industry.

This intuition also suggests that in the general model with multi-unit generators, prices will tend to be higher than in the model in which these same units act independently. As indicated above, raising the offer price of one set will have an external effect on other sets in that it increases the expected system marginal price. An owner who controls many units will internalise part of this externality and will thus have an additional incentive to increase its offer prices. In particular, this 'coordination incentive' is stronger the more units an owner controls. It therefore seems reasonable to conclude that for a given number of generating sets in the industry, system marginal price will be a decreasing function of the number of owners, or generators controlling the sets, i.e. the industry concentration ratio.

III. THE U.K. ELECTRICITY INDUSTRY[9]

In this section we present empirical evidence on bidding behaviour in the UK electricity industry. Since our model is obviously too simplified to be tested directly against the evidence, our purpose is rather to demonstrate that the types of strategic behaviour we have identified in our model are at least consistent with actual historical bidding behaviour, and that our most important conclusion for policy purposes, namely that bids will tend to be above generation costs, is supported by the evidence.[10]

III.1. *Structure of the UK industry*

There are three main generating companies in the system for England and Wales: The privately owned National Power (with approx. 52% of the generating capacity of the old Central Electricity Generating Board) and PowerGen (with 33%), and the publicly owned Nuclear Electric (with 15%).[11] Nuclear Electric's production is completely based upon nuclear power. It therefore functions entirely as a base-load producer and its capacity is bid in at (virtually) zero. Thus there are in reality only two significant strategic players in the electricity spot market.

Each day the generating companies submit 'bids' to the National Grid Company which give the minimum prices at which they are willing to supply electricity from each generating unit (or 'Genset').[12] A 'merit order' is then constructed from the bids, with sets ranked in ascending order, and a despatch schedule determined to match supply and predicted demand for each half-hour of the following day. System marginal price (SMP) – the major component of the price paid to each despatched genset – is determined by the bid price of the marginal despatched set. In most half-hour periods (Table A periods), each despatched genset is paid, in addition to system marginal price, a 'capacity element', intended to reflect the probability of loss of load, i.e. a power shortage. In Table B periods, when there is expected to be an excess of running, partly-loaded capacity, capacity payments are not made, and only the 'incremental bid prices' are used to determine system marginal price.[13]

At vesting, on the 31 March 1990, 'contracts for differences' were placed between the two major generators and the regional electricity supply companies

[9] See Vickers and Yarrow (1990), Green (1991*a*), James Capel & Co. (1990) and Holmes and Plaskett (1991) for descriptions of the new UK electricity industry. Vickers and Yarrow in particular provide a discussion of a broad range of issues relevant for the evaluation of the deregulation.

[10] Green (1991*b*) claims to have found bids to be at or near generation costs on most of the two major generators' generating units. However, the recent report by the regulator (Offer, 1991) cites bids well above estimates of 'avoidable generation costs' as a cause of concern in its attempt to evaluate how well competition in the new system is working.

[11] In addition there are some suppliers in Scotland and on the continent connected to the system in England and Wales, but these are for the time being of little importance.

[12] Amongst a great deal of other information – see von der Fehr and Harbord (1992*a*) and NGC (1991) for further details.

[13] There are further additional complexities to the system. These have been described elsewhere (c.f. NGC (1991), Green (1991*a*, *b*), James Capel & Co. (1990)) and further details are provided in von der Fehr and Harbord (1992*a*).

covering approximately 85% of the generators' capacities.[14] These are option contracts under which the difference between the spot, or 'pool' price of electricity and the contract strike price is paid to the purchaser (i.e. the regional electricity company) on a specified number of units. These option contracts have significantly reduced the incentives of the generators to bid pool prices above the level of contract strike prices, since any difference between the pool price and contract strike prices is paid back to the regional supply companies in the form of a difference payment on the amount of capacity contracted for. One would therefore not expect to see the type of 'non-competitive' bidding behaviour predicted by the theoretical model mirrored in the historical bidding data.[15] By March 31, 1991 however a proportion of these contracts had expired (approx. 15%), and the rest are due to expire by March, 1993. With contract coverage lowered to about 70% of the generator's capacities, 'strategic' or 'non-competitive' bidding behaviour becomes more likely, and so one expects to see in the first year of operation of the new system, bids reflecting generation costs – since contract strike prices were chosen to represent expected marginal generation costs – and after February/March 1991 a possible change in 'regime' to more aggressive, non-competitive bidding. It is precisely this kind of 'change in regime' that we see reflected in the data to April 31, 1991.

III.2. *Generator bidding behaviour*[16]

In the figures below two different ways of describing the bidding behaviour of National Power and PowerGen for the period from July 1990 to April 1991 are depicted. Fig. 1 and 2 show the 'actual bids' of the two major generators for each level of output on particular weekdays of the year, i.e. the generators' 'supply schedules'. Fig. 3 on the other hand represent the average weekly bids of each generator for generating sets of a particular size and fuel type. The former are thus 'snapshots' of generator bids at particular points in time, while the latter give a longer-term picture of generator bidding behaviour over the period.

Fig. 1 *a* shows the supply schedules of both generators on 2 July 1990. Since PowerGen's capacity is approximately 64% of National Power's, its supply schedule becomes vertical much earlier, at approximately 12,000 MGWh. Fig. 1 *b* and 1 *c* compare the generators' estimated cost schedules to their supply schedules. Since the generators' cost schedules were constructed by summing over all of their capacity, while on a given day some capacity will be declared unavailable (due to maintenance, etc.), it is to be expected that the supply schedules become vertical before the cost schedules do. Apart from this

[14] Details may be found in the share offer prospectus, Kleinwort Benson Ltd. (1991).

[15] von der Fehr and Harbord (1992 *b*) model the strategic incentives of the generators with simple one-way and two-way difference contracts. Helm and Powell (1992) and Powell (1991) also contain discussions of the importance of contracts in the UK electricity industry.

[16] In von der Fehr and Harbord (1992 *a*), appendix B, we provide information concerning our sources and analysis of the bid data. The interested reader is referred there for this information and for further empirical evidence.

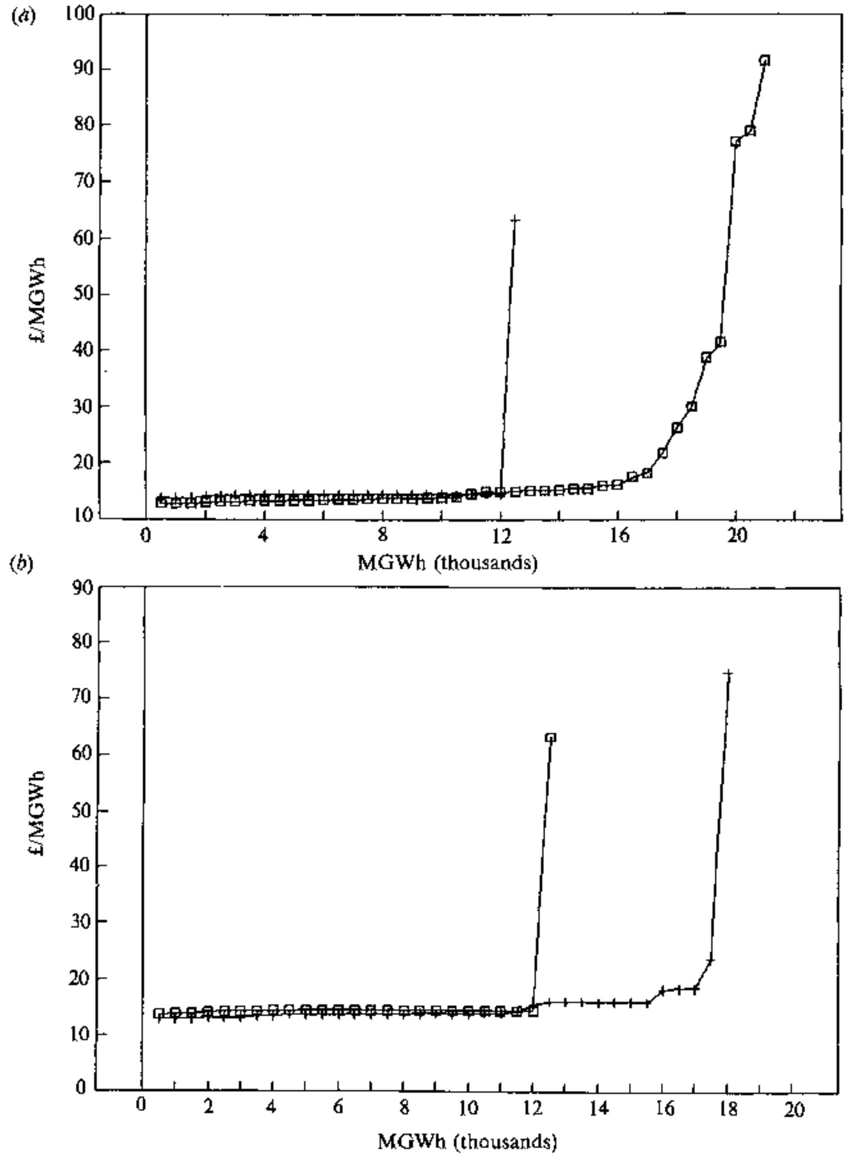

Fig. 1. For legend see facing page.

however, the generators seem to have bidding a very close approximation to their cost schedules. Thus during the first 8–10 months of the operation of the new system the evidence seems to suggest that the two major suppliers were bidding 'competitively', i.e. at cost.

The figures for 22 February 1991 begin to indicate a different pattern. PowerGen's supply schedule on this day lies uniformly above National Power's (Fig. 2*a*), with marked differences in bids in 2,000 to 10,000 MGWh range. In Figs. 2*b* and 2*c* we see that PowerGen's supply schedule also lies uniformly above its cost schedule, while National Power's supply schedule is below its cost

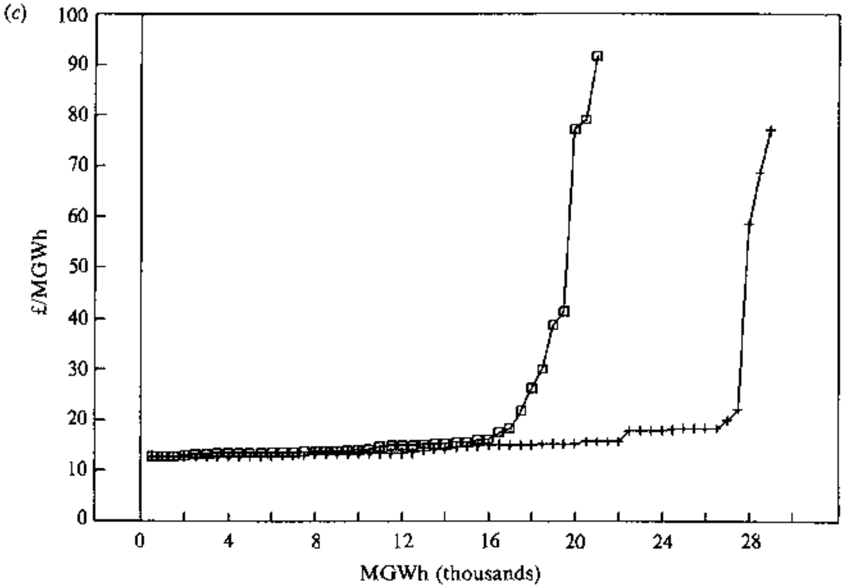

Fig. 1. As supplied: 2 July, 1990. (*a*) Supply curves: □, NPBIDS; +, PGBIDS. (*b*) PowerGen bids *vs.* costs: □, PGBIDS; +, PGCOSTS. (*c*) National power bids *vs.* costs: □, NPBIDS; +, NPCOSTS.

schedule from 0 to approximately 10,000 MGWh, the range of output covered by its large, coal-burning sets (once adjustments for availability have been made), and thereafter is above it.

While these figures do not provide enough data to allow us to reach any firm conclusions, they do seem to indicate a change in the pattern of bidding behaviour. In particular the figures for February indicate more sophisticated patterns of bidding behaviour than simply bidding in at cost. This is confirmed by an examination of the weekly averages of bids on gensets of a particular size and fuel type over the entire period from May 1, 1990 to April 30, 1991.[17] In Fig. 3 average weekly bids for National Power's and PowerGen's large coal sets are shown.[18] It is apparent that at around week 40 (early December, 1990) both generators altered their bidding behaviour significantly, and in opposite directions. National Power's bids on its large coal sets drop dramatically from an average of approximately £14/MGWh to well below £10/MGWh in almost all weeks, and its largest coal sets were occasionally bid in at below £2/MGWh. PowerGen, on the other hand, increased its bids on its large coal sets by an average amount of approximately £1/MGWh. This pattern of bids remained stable from December 1990 to the end of April 1991.

As noted above, a possible explanation for these results is that since in the first part of this period contract coverage for each generator was approximately

[17] In figure 3, week 5 is the week beginning 1 May 1990.

[18] C5 indicates a coal set of greater than 500 MGW and C6 a coal set of greater than 600 MGW. We concentrate on coal sets since for other sets the picture is blurred by the frequent changes in input prices, i.e. prices of oil and gas.

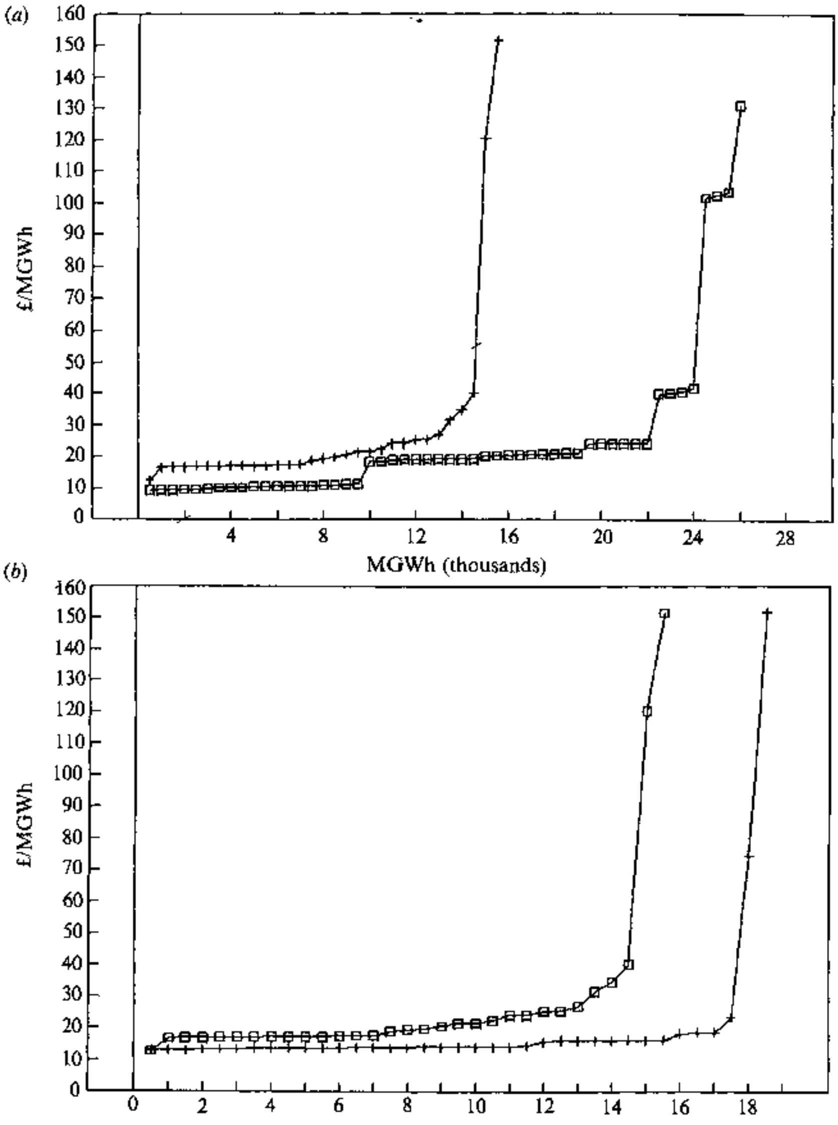

Fig. 2. For legend see facing page.

85% of their capacities, contract strike prices put downward pressure on spot prices, while in the latter part, when contract coverage was less, this pressure was eased. However, contracts only started expiring right towards the end of the period (31 March 1991) while the change of pattern occurs in December 1990.

An alternative explanation is given by our model. The first period more or less coincides with the warm season, and based on the model predictions we expect to observe prices closer to costs when demand is low. Thus for demand levels below approximately 27,500 MGWh, which is typical during warm

(c)

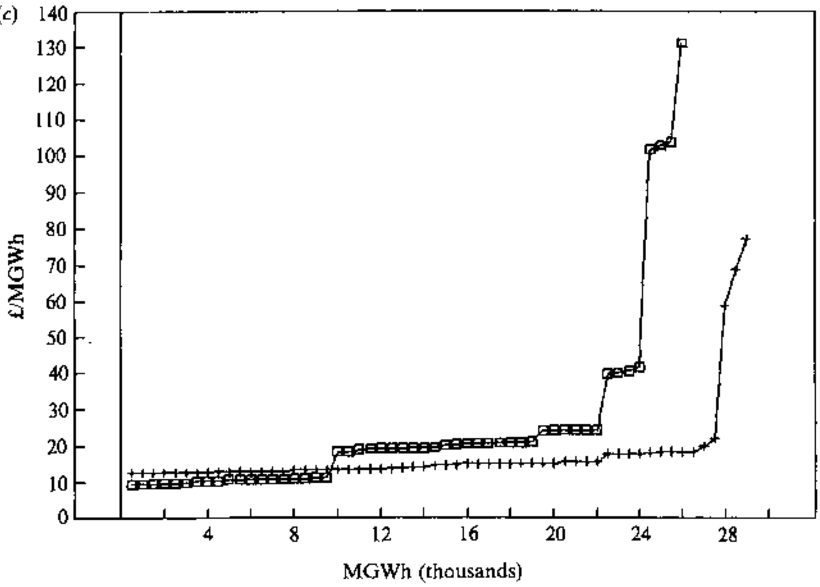

Fig. 2. As supplied: 22 February, 1991. (a) Supply curves: □, NPBIDS; +, PGBIDS. (b) PowerGen bids vs. costs: □, PGBIDS; +, PGCOSTS. (c) National power bids vs. costs: □, NPBIDS; +, NPCOSTS.

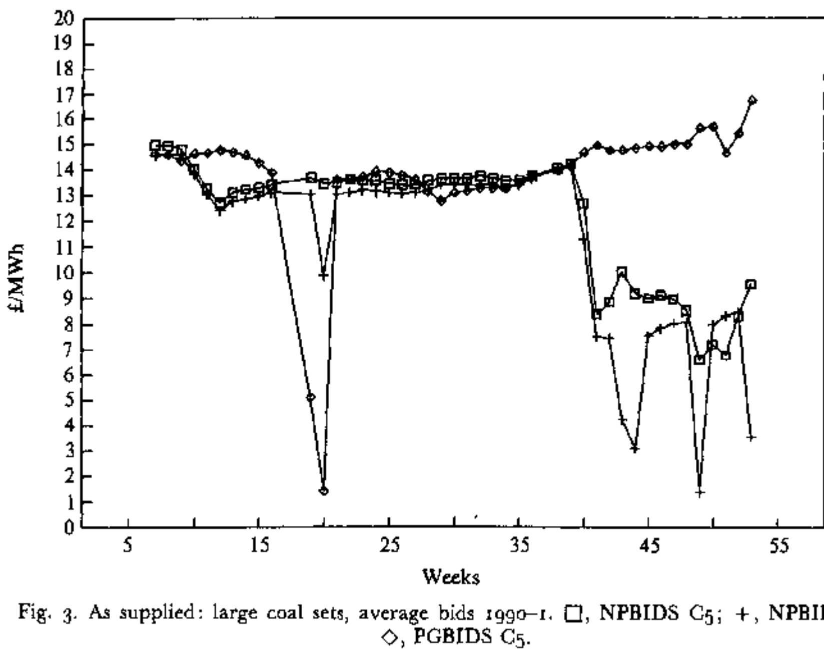

Fig. 3. As supplied: large coal sets, average bids 1990–1. □, NPBIDS C5; +, NPBIDS C6; ◇, PGBIDS C5.

seasons, large coal sets are almost exclusively the 'marginal sets' which determine system marginal price. Furthermore, since in the warm season demand may fall very low at night and in early morning, there will be strong competition to be despatched (see the discussion in Section II.1 and II.2). In the colder season, however, demand is always so high that sets with low rank will never become marginal. Therefore, from December 1990 onwards PowerGen's large coal sets were determining system marginal price over a large number of periods, while National Power's large coal sets were being bid in low enough so that they were certain to be despatched. This type of bidding behaviour then, has the flavour of the equilibria described in Section II.3.

IV. AN ALTERNATIVE PRICING RULE

As shown in Section II, generators will typically choose bids greater than their marginal costs, and thus system marginal price will tend to exceed the marginal costs of each of the operating units. Furthermore, since less efficient sets may submit lower offer prices than more efficient sets, inefficient despatching may result. It is therefore an interesting question whether the regulatory rule can be modified so as to induce truthful revelation of costs and, as a result, efficient despatching.

In Section II we noted that the model may be interpreted as a first-price auction since system marginal price is determined by the offer price of the marginal *operating* set. Thus a generator's bids will determine the price received in the event that one of its sets is marginal. The fundamental insight of William Vickrey (1961) was that by making the price received by a player independent of its own bid, marginal cost pricing can be induced as a dominant strategy for all participants. The reason for this is that in such a set-up a generator can only influence its own payoff to the extent that it affects the probability of being called into operation. A generator will prefer to be operating for all realisations of demand such that its payoff is positive and *vice versa*. Therefore, offering to supply at a price equal to marginal cost becomes a dominant strategy because it maximises the probability of being called into operation whenever the generator's payoff is expected to be non-negative.

In the working paper version of this article (von der Fehr and Harbord, 1992*a*) we extend the Vickrey result by considering a mechanism that lets the price paid to generator n be determined by the intersection of demand with the residual (i.e. net of the capacity of generator n) supply curve. With this pricing rule, despatching is efficient since generators are always ranked in order of increasing marginal cost and thus real generation costs are minimised. Furthermore, it is easy to verify that revenue equivalence holds between the two pricing rules when valuations are drawn from the same distribution as we would expect from the Revenue Equivalence Theorem (Vickrey, 1961; McAfee and McMillan, 1987). It turns out to be difficult to establish the sign of the difference in total payments in general, but in the duopoly model one can show that payments are never larger with the alternative pricing rule. Such an improved pricing performance echoes the result in the optimal-auction literature that second-price sealed-bid auctions yield higher payoffs to the auctioneer than do first-price sealed-bid auctions (McAfee and McMillan, 1987; Myerson, 1981 and Maskin and Riley, 1989). Thus, some of the first-price/second-price comparison results found in the standard auction literature extend to this setting as well.

V. CONCLUSION

Price competition in the deregulated UK market for electricity has been analysed as an auction. In doing so, we have demonstrated that under the existing institutional set-up there is likely to be above marginal cost pricing and inefficient despatching may result. While these points have been argued elsewhere (see for instance, Vickers and Yarrow, 1991, or Green, 1991*a*), the arguments have been largely informal and usually based upon standard models of oligopoly pricing, and hence somewhat inconclusive. A major purpose of the present paper has been to address these issues in a formal model specifically designed to capture the essential elements of the new UK system.

To our knowledge Green and Newbery (1992) (see also Newbery (1991)) is the only other model specifically designed to study the bidding behaviour of the generators under the new UK system. While our conclusions echo theirs in many respects, our results have cast some doubt upon the type of equilibrium analysis they have employed, i.e. Klemperer and Meyer's (1989) 'supply functions do not appear to generalise to the case where supply functions must assumption that firms submit smooth, i.e. continuously differentiable, supply functions do not appear to generalize to the case where supply functions must be discrete 'step functions', even when the 'step-length' can be made very small. Indeed, we have found that for a wide range of demand distributions pure-strategy (i.e. supply function) equilibria will not exist in this case. It is therefore reassuring to find that Green and Newbery's most significant conclusion for policy purposes, viz. above marginal cost pricing, is also a property of the model analysed here, and hence does not depend upon the particular assumptions they impose.

In Section III we have presented empirical evidence on the bidding behaviour of the two major generators in the UK industry which has tended to support the conclusions of our theoretical model. While not claiming to have 'tested' the model in any sense, we have been able to demonstrate that at the very least the model is not contradicted by the empirical evidence, and that the bidding strategies of the generators may be viewed, at least in part, as conforming to the types of strategies described by the theory. While our empirical conclusions, in particular, bids greater than generation costs, do not agree with those of Green (1991*b*), they have been confirmed elsewhere, significantly in the recent report of the regulator OFFER (1991). There thus now exists serious evidence, both theoretical and empirical, that competition in the new electricity supply industry for England and Wales may not be achieving the purposes for which it was originally designed, i.e. the efficient generation of electricity, sold at competitive prices to consumers.

While the analysis presented here would appear to be useful in providing a framework for studying pricing behaviour in the deregulated UK electricity industry, the importance of our conclusions is limited by the extent to which they do not take into account opportunities for collusive behaviour between the generators, or the effects of long-term contracts between suppliers and purchasers (or third parties). These problems call for further research.[19]

University of Oslo

London Economics

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[19] In a companion paper – von der Fehr and Harbord (1992*b*) – the model of the present paper is extended to account for the presence of long-term contracts.