Competition in the British Electricity Spot Market

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Most of the British electricity supply industry has been privatized. Two dominant generators supply bulk electricity to an unregulated "pool." They submit a supply schedule of prices for generation and receive the market-clearing price, which varies with demand. Despite claims that this should be highly competitive, we show that the Nash equilibrium in supply schedules implies a high markup on marginal cost and substantial deadweight losses. Further simulations, to show the effect of entry by 1994, produce somewhat lower prices, at the cost of excessive entry; subdividing the generators into five firms would produce better results.

I. Introduction

The British Electricity Act of 1989 set out dramatic structural changes to the electricity supply industry that came into effect on March 31, 1990. According to the share offer brochure, "The new industry structure is designed to encourage competition in the generation and supply of electricity and to regulate prices for activities where the scope for competition is limited, such as transmission and distribution." Under the new structure the activities of the former public-sector Central Electricity Generating Board (CEGB) have been transferred to four successor companies.

> Three of these—National Power plc, PowerGen plc and Nuclear Electric plc—are engaged predominantly in genera-

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> tion. The CEGB's coal, oil and gas powered stations have been divided between National Power and PowerGen which now compete in the generation of electricity with each other and with other generators. The CEGB's nuclear power stations have been transferred to Nuclear Electric which will remain in the public sector. The high voltage transmission system known as the national grid is now owned and operated by The National Grid Company plc (NGC), the fourth successor company of the CEGB. NGC is itself owned through a holding company by the Twelve Regional Electricity Companies. As well as operating the high voltage transmission system, which remains a monopoly business, NGC has a central role in coordinating power stations so that the generation of electricity can be matched to demand. [Pp. 4–5]

Although the transmission and distribution of electricity are to be regulated, generation is not, on the basis of two arguments. The first is that the generating companies will compete on price as Bertrand oligopolists, and the resulting fierce competition should result in efficient pricing. Since electricity is effectively nonstorable, generation and demand must be matched on a minute-by-minute basis, and this requires every station to follow the operating instructions of a central dispatcher, turning on and off as demand varies during the day. Every day, each generator submits price schedules to the grid dispatcher in NGC, and the dispatcher then meets demand at the lowest cost to the system. In each half hour, all generators are paid the price bid by the marginal unit operating in that period. The hope is that each generator will attempt to undercut its rival and thus ensure low prices. Green (1991*b*) describes the system in greater detail and shows that it would produce optimal prices for electricity if generators were to bid at marginal cost.

The second defense of the lack of regulation is that entry into the industry will be open to any plausible supplier and that new technology using high-efficiency combined cycle gas turbines (CCGT) makes entry at modest scales (300–600 megawatts [MW]) simple and quick: construction times are short, and the technology is readily available from a number of suppliers and is competitive with existing larger thermal stations.

The aim of this paper is simple and practical. In the early years at least the wholesale electricity market will be supplied by an effective duopoly. The third generator, Nuclear Electric, supplies base load at a price that would normally be below that of either National Power or PowerGen, so that all variations in demand will be met by variations in supply by either of the private duopolists. How will profit-maximizing duopolists behave in designing their supply schedule if they are uninhibited by the threat of regulation? Is the argument valid that there will be sufficient competition to render regulation unnecessary in the specific case of the British electricity supply industry? If not, as we shall argue, what is the scope for raising prices above the efficient level, and what does this imply for industry efficiency? What structure would have been required to reduce this inefficiency to modest levels? How effective is entry at introducing competition and reducing market power, and at what cost in terms of excess capacity?

The question is of intense practical significance, not just in the United Kingdom, because the U.K. electricity privatization is being closely observed as a possible model for regulatory reform in a number of countries. Given the attractions of competition over regulation and the difficulties of ensuring efficient regulation (Stigler 1971), it is clearly desirable to identify cases in which regulation can be discarded. Empirical studies of the effects of electricity deregulation are scarce, since it has rarely been contemplated outside the United States, let alone tried. The United States is one of the few countries in which the issue has been actively debated, though to date most studies have attempted to assess the potential for deregulation by measuring the extent of market concentration in regional submarkets. Thus Weiss (1975) calculated four-firm concentration ratios for capacity within 100 and 200 miles of 10 of the 13 largest load centers. Schmalensee and Golub (1984) estimated effective concentration in deregulated wholesale electricity markets. They found that some markets exhibited persistently high effective concentration and that in others the degree of concentration would depend sensitively on the existence of transmission capacity constraints, about which usable information was lacking. They urged caution in advocating deregulation in these and the concentrated markets.

Similarly, before privatization in the United Kingdom, a number of commentators examined the consequences for efficiency of different choices for the structure of the industry after privatization and the possible need for regulation. Henney (1987) argued that the CEGB should be split into nine or 10 separate companies and that none of these should be allowed to grow subsequently to the point at which it would supply more than 20 percent of the market. Sykes and Robinson (1987) claimed that Henney's proposal could not be accomplished within the time scale required by political considerations, but they proposed another mechanism that would have eventually created five or six competing generators. Vickers and Yarrow (1988) did not advocate a particular privatization strategy but stressed the importance of regulation in all sectors of the electricity supply industry. Helm (1988), writing after the publication of the White Paper *Privatising Electricity* (Her Majesty's Stationery Office 1988) but before the full details of the restructuring had been decided, also stressed the need for regulation, given the likely entry barriers.

One part of the electricity market that is already deregulated is the U.S. bulk power market. Hahn and Van Boening (1990) have recently used laboratory experiments to study the choice of mechanisms for the exchange of short-term electricity between different generators. A number of regional power pools in the United States have formal brokers that normally use a "split-savings" rule. In this rule, bids and offers are ranked, the highest bid is matched with the lowest offer, and so on, with the transaction occurring at a price halfway between the bid and offer. Some of these regional brokers handle as many as 50 firms, and the experimental design was modeled on the Florida Power Broker, which deals with 37 firms. The experimental design compares the efficiency of the split-savings rule with that of a single-price auction. It found the latter to be superior, though both mechanisms are prone to systematic misrepresentation of marginal costs (which are supposed to determine the bids and offers). The applicability of these lessons to total deregulation of generation is not so clear, though one should be worried by the prevalence of misrepresentation. Perhaps the most optimistic part is the finding that auction markets, which are similar to the British spot market, may be more competitive than alternative systems in current use. In the same vein, Hobbs (1982) studied the option of deregulating the upstate New York market and found that if the equilibria were Bertrand (as they would be in the British case), deregulation would be beneficial.

Section II of the paper gives the theoretical foundations for a supply function model of the electricity spot market. In Section III, this model is used to find the short-run profit-maximizing equilibrium of the industry, ignoring the threat of entry, which can follow only a construction period of at least 2 years. Significant entry will be possible by 1994, and so Section IV is set in that year. It explores the outcome in which the duopolists choose a low-price, high-output strategy in the short run, which minimizes entry and should maximize their long-run profits.

II. Modeling the Electricity Spot Market

The electricity spot market is unlike almost any other market, for prices are determined in advance for each level of demand expected during the following day. As the marginal cost of generation varies widely from plant to plant (from almost zero for nuclear power to very high values for the peaking gas turbines), the generators submit not just a single price at which they would be willing to supply unlimited amounts of power, but a whole schedule of prices. Each segment of this schedule specifies the capacity of the set in question and the price at which the generator is willing for it to be switched on by the dispatcher. With the help of GOAL, a large computer program, the dispatcher calculates the operating schedule that minimizes the costs of meeting demand and identifies the marginal plant in each half hour. The price that the marginal plant bid is paid for all the electricity generated in that half hour, as in a multiunit, single-price auction.

Fortunately, the techniques needed to characterize an equilibrium in supply schedules have been recently provided by Klemperer and Meyer (1989), and these, with minor modification to fit the particular circumstances of the electricity spot market, can be readily applied to the problem in hand. Indeed, the electricity spot market is probably the best example of a market characterized by a supply function equilibrium.[1]

The following formulation makes a number of simplifying assumptions, in the interests of tractability. We assume that each firm submits a smooth supply schedule, relating amount supplied to marginal price. In practice, each firm bids prices for each generating set, so that the operating cost elements of the bid schedule form a step function, not a smooth curve.[2] The generators also submit a price for each time their set is started, which introduces an important nonconvexity into the problem, and additional payments for a nonzero loss of load probability are made as demand approaches the available capacity. (The start-up price and loss of load payments are usually important only at peaks in demand, and as the bid prices may rise very sharply at high output levels in our model, the effect may be very similar.) All these practically important qualifications are likely to increase rather than reduce the market power of the firms, so that by ignoring them, we are presenting an optimistic view of the workings of the spot market.

We look for only the noncooperative Nash equilibria of the spot market as a single-shot game. Since the bidding process is repeated daily and bids are published shortly after they are made, we do not feel that there would be any "learning" problems in reaching these equilibria. It could be argued that these conditions are ideal for the

[1] Bolle (1990) has also applied the Klemperer-Meyer framework to the electricity spot market, modeling supply functions for three specifications of a bidding game. One of them corresponds to the one considered here.

[2] It is an open question whether the bidding strategies of the firms will differ significantly if they are forced to provide a step function, or whether they are allowed to provide a smooth schedule.

duopolists to maintain a collusive equilibrium in the repeated game, an outcome we do not study. The Folk theorems would imply that a range of equilibria should be possible and that they would all produce higher profits, higher prices, and lower welfare than the unattractive single-shot equilibria we report. The possibility of collusion only worsens an already unattractive situation.

Demand for electricity can be described in two ways: by demand at different hours of the day and by the load duration curve, giving the number of hours that demand exceeds a given level. Figures 1 and 2 illustrate this for typical days in 1988/89. We use the load duration curve, so that demand is monotonic over "time." If the load duration curve for next day's supply were known and if one supplier knew or could predict the supply schedule to be offered by the other, then the problem of choosing the supply schedule to maximize tomorrow's profits can be tackled adapting Klemperer and Meyer's techniques.

A. *Symmetric Duopoly*

We first consider the simplest case of a symmetric duopoly, which can be extended to that of an n-firm oligopoly and, with more difficulty, to the practically important case of an asymmetric duopoly.[3] The notation and argument follow Klemperer and Meyer closely, except that we consider variations over time rather than states of the world. Suppose that the load-duration curve net of nuclear supply at any moment during the day is predictable with certainty and is given by $D(p, t)$, where t is "time," that is, the number of hours of demand higher than D, and p is the spot price. (Actually, following Klemperer and Meyer, p is the spot price *less* the marginal cost of supplying an infinitesimal amount, shifting the origin so that the marginal cost schedule passes through the origin. The figures show the true prices and marginal costs.) We assume that for all (p, t), $-\infty < D_p < 0$, $D_{pp} \leq 0$, and $D_{pt} = 0$. (This latter assumption is made primarily for computational simplicity and since we have no strong empirical priors that it is unreasonable.)

The net demand facing firm i at moment t when the other firm, j, has supply schedule $S^j(p)$ is $D(p, t) - S^j(p)$. Let the effective generating costs of supplying q be $C(q)$ with marginal cost $C'(q)$.[4] The strategy for firm i is formally a function mapping price into a level of output

[3] Newbery (1991) derives the n-firm case, which we use to solve for the quintopoly solution later in this paper.

[4] With the change of origin, the effective cost is defined as $C(q) \equiv C^*(q) - qC^{*\prime}(0)$, where $C^*(q)$ is the true total cost of generating q.

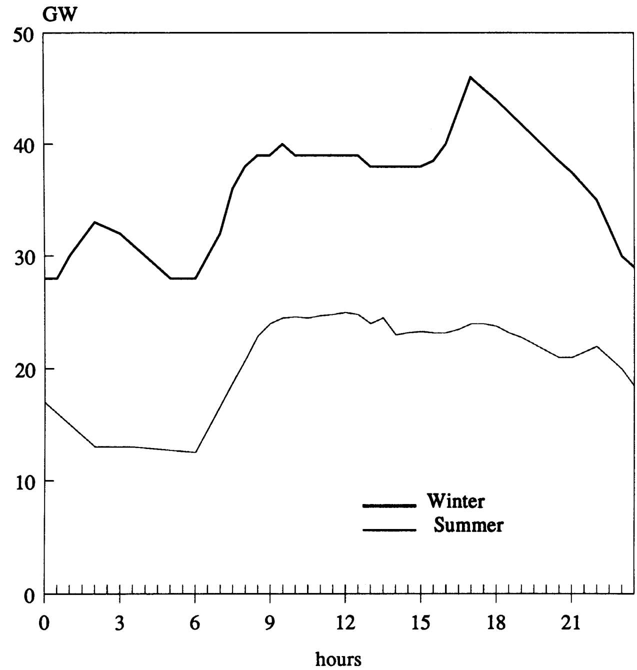

FIG. 1.—Summer and winter demand, 1988/89 (Electricity Council 1989)

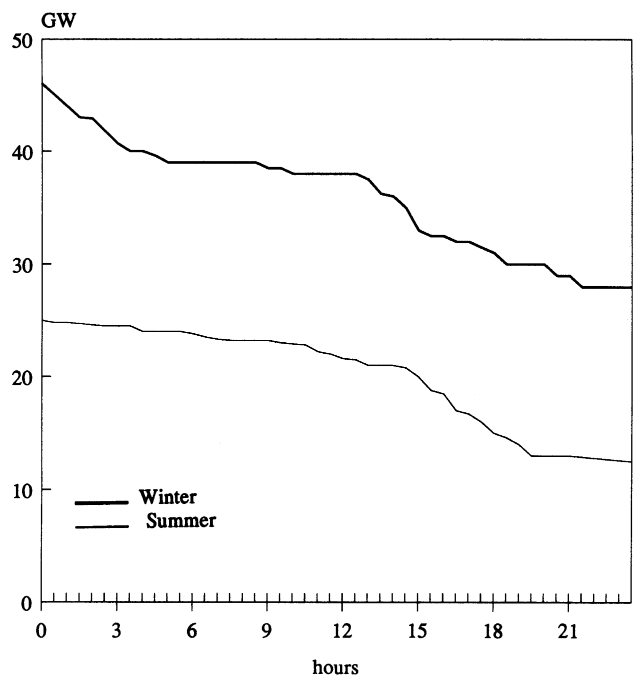

FIG. 2.—Load duration curves, 1988/89 (Electricity Council 1989)

independent of time, t: S^j: $[0, \infty) \to (-\infty, \infty)$.[5] Each firm submits its supply function to the grid dispatcher simultaneously (the day before), and the dispatcher then determines the spot price and each firm's supply by solving for the price-output pair that equates supply to demand at each moment. That is, at each moment t the dispatcher announces the lowest price $p(t)$ such that $D(p(t), t) = S^i(p(t)) + S^j(p(t))$, provided that such a price exists. If such a price does not exist, the firms are paid zero. On the assumption, justified by Klemperer and Meyer, that profit-maximizing price-output pairs can be described by a supply function $q_i = S^i(p)$, at any t, the choice of q_i implies a particular value of p, and so the profit-maximizing solution can be found by maximizing profit, $\pi_i = pq_i - C(q_i)$, with respect to p:

$$\pi_i(p) = p[D(p,t) - q_j(p)] - C[D(p,t) - q_j(p)]. \tag{1}$$

So the first-order condition can be written as

$$\frac{dq_j}{dp} = \frac{q_i}{p - C'(q_i)} + D_p. \tag{2}$$

Solving for the symmetric solution in which $q_i = q_j = q$ gives

$$\frac{dq}{dp} = \frac{q}{p - C'(q)} + D_p. \tag{3}$$

The second derivative of firm i's profit is

$$\frac{d^2\pi_i}{dp^2} = 2\left(D_p - \frac{dq_j}{dp}\right) - C_i''\left(D_p - \frac{dq_j}{dp}\right)^2 + (p - C_i')\left(D_{pp} - \frac{d^2q_j}{dp^2}\right).$$

Provided that q_i and q_j satisfy (2), this can be transformed to (see claim 7 in Klemperer and Meyer's appendix)

$$\left(D_p - \frac{dq_j}{dp}\right)\left(1 + C_i''\frac{dq_j}{dp}\right) - C_i''\left(D_p - \frac{dq_j}{dp}\right)^2 - \frac{dq_j}{dp}, \tag{4}$$

which is negative, confirming the local optimality of supply schedules that satisfy (2) and, hence, the special symmetric case (3).

The behavior of the differential equation that characterizes the symmetric supply function equilibrium can be further analyzed (see Klemperer and Meyer 1989, p. 1254). Consider points (q, p) such that

$$C'(q) < p < C'(q) - \frac{q}{D_p}. \tag{5}$$

Then at such points $0 < dq/dp < \infty$, and the trajectory of the differential equation through this point has a well-defined positive directional

[5] Here we follow Klemperer and Meyer exactly and avoid nondifferentiabilities by the device of supposing that negative outputs are possible. Later we shall require the output range to be limited to $[0, k]$, where k is capacity.

slope. It can be shown that all such trajectories pass through the origin, where they have the same slope. The next step is to consider the stationaries whose equations define the lower and upper limits in equation (5). Consider first the equation $p = C'(q)$. This is the supply schedule of a perfectly competitive firm, and along this curve (shown as the lower dotted line in fig. 3), $dq/dp = \infty$, so $dp/dq = 0$. Any trajectory that intersects the lower stationary reaches it with horizontal slope at a point such as C in figure 3, and once it has crossed the stationary it will have a negative slope, eventually reaching the q-axis.

If the trajectory reaches the upper stationary (the dashed line in fig. 3) at a point such as B, its slope there will be $dq/dp = 0$, or $dp/dq = \infty$. It will cross the stationary vertically and then bend back, eventually reaching the p-axis. The upper stationary also has a simple interpretation as the Cournot supply schedule, for if firm j has unresponsive output k_j, then firm i is an effective monopolist with $q_i = D(p, t) - k_j$. The profit-maximizing choice of p satisfies

$$q_i + [p - C'(q_i)]D_p = 0,$$

or

$$p = C'(q) - \frac{q}{D_p}. \quad (6)$$

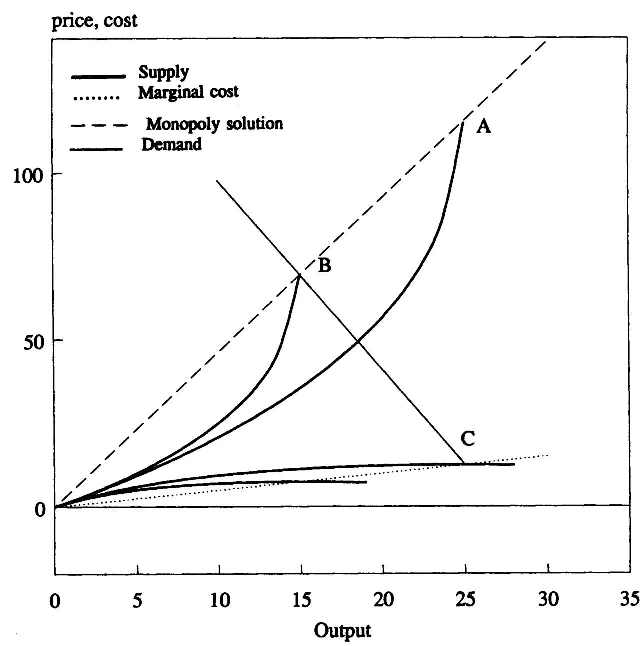

FIG. 3.—Feasible supply function equilibria

In general, therefore, the duopoly supply schedule lies between the competitive and Cournot schedules along a trajectory such as $0A$ in figure 3. Candidates for equilibrium supply schedules must not intersect either stationary over the range of possible price-output pairs. Klemperer and Meyer (their proposition 4) prove that if the demand schedule can be arbitrarily high (with some probability), then there is a unique solution; otherwise there may be a connected set of equilibria bounded by an upper and lower supply schedule (their proposition 2). Thus in figure 3, if BC is the maximum demand $D(p, 0)$ (remember that the load-duration curve has its maximum definitionally at $t = 0$), then all solutions to (3) lying between $0B$ and $0C$ are possible solutions. All that we can say is that if firm j is known to have chosen one such schedule, $q_j(p)$, and if there are no supply constraints, then $q_i = q_j(p)$ is the profit-maximizing response of firm i. Capacity constraints will narrow down the range of equilibria, as will the threat of entry.

B. *Supply Constraints*

Suppose that neither firm can supply beyond $q = k$. At $q_j = k$, the optimal response of firm i is the Cournot solution

$$q_i = -D_p(p - C' - \mu), \quad \mu \geq 0, q_i \leq k, \mu(k - q_i) = 0,$$

where μ is the shadow price of the capacity constraint. Consider figure 4, in which the highest demand schedule, $D(p, 0)$, meets the capacity constraint at point B. The schedule $0B$ satisfies the differential equation of (3) and is the lowest supply schedule that can be an equilibrium. If one firm supplies along a lower schedule, it will reach capacity before demand is at its maximum. The other firm will then find it profitable to deviate to the Cournot supply, to which the proposed schedule is not the best response. Schedule $0A$, which cuts the Cournot schedule at A vertically, is also a candidate for equilibrium since it satisfies the first-order (and second-order) conditions for an optimum and does not violate the capacity constraint. The effect of capacity constraints is thus to narrow the range of feasible equilibria, and in extreme cases in which the intersection of maximum demand with Cournot supply, A, occurs at full capacity, the equilibrium will be unique. If there is some chance that demand will be capacity constrained at the Cournot price, then, following the argument of Kühn (1991), this will also imply uniqueness. If, further, the convention were followed that the supply schedules bid should not vary from day to day and if there were some chance that demand would be capacity constrained on the day of highest demand, then the unique solution through the intersection of the capacity constraint and the Cournot schedule would hold throughout the year. Note that this

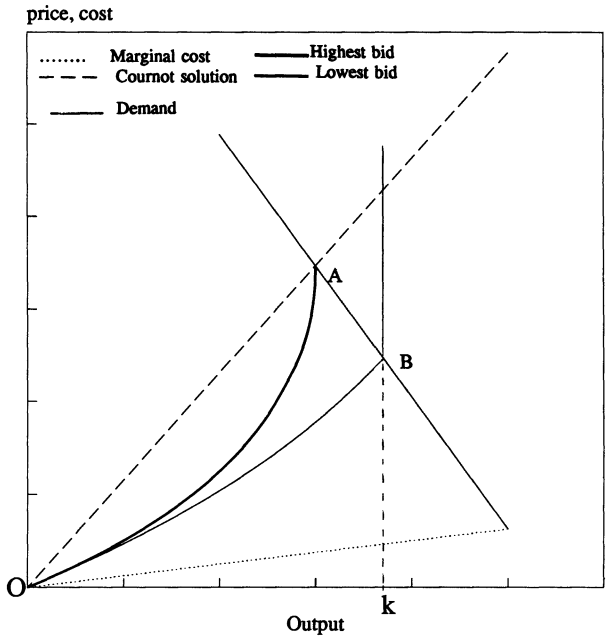

FIG. 4.—Feasible solutions with capacity constraints

convention might need regulatory oversight, since the firms can do better choosing the most profitable supply schedule given the maximum realized level of demand forecast for each day ahead.

The supply schedule that intersects the Cournot solution at maximum demand cannot be improved on by either firm acting alone and yields higher short-run profits than any other feasible schedule. It is therefore a natural candidate for the choice of supply schedule, though not necessarily the only such candidate. Newbery (1991) has developed a simplified analytical version of the present model with linear costs and demand and n firms. He shows that if incumbents can credibly commit to a supply strategy and if entrants have access to the same technology as incumbents for capacity expansion at any scale (which is not unreasonable given the attractiveness of modest scale CCGT technology), then incumbents earn higher long-run profits coordinating on the highest-equilibrium supply strategy with the lowest prices. We explore this possibility in our more realistic model of the British spot market below.

C. *Equilibria with Asymmetric Firms*

The differential equations (2), one each for i and j, give two first-order conditions for a local profit-maximizing supply schedule, for an asymmetric duopoly, for which the second-order conditions are also satisfied. In the British case the two firms differ primarily in their capacities, with National Power being 50 percent larger than PowerGen. Let p^* be the price at which the smaller firm is on its Cournot schedule at full capacity (i.e., satisfies [6]):

$$p^* = C'(k_2) - \frac{k_2}{D_p(p^*, 0)},$$

where k_2 is the capacity of the smaller firm. (By the assumption that $D_{pt} = 0$, the second term is independent of time and hence has been evaluated at $t = 0$.) If, at this price, the Cournot supply of the larger firm, $q_1(p^*)$ (which satisfies [6] at full capacity of the smaller firm),

$$p^* = C'(q_1) - \frac{q_1}{D_p(p^*, 0)},$$

together with the full capacity output of the smaller firm, is less than maximum demand at this price, that is,

$$q_1(p^*) + k_2 < D(p^*, 0),$$

then in one equilibrium pair of supply strategies, the smaller firm reaches full capacity at the point at which its supply function meets the Cournot equilibrium vertically (at p^*); the second firm also reaches its Cournot equilibrium at the same price, p^*. Following the same argument as before, this is the lowest pair of supply functions that are optimal against each other. They are also the highest such pair, and hence the equilibrium price strategies are uniquely defined. If, on the other hand, maximum demand at this price is less than twice the capacity of the smaller firm, that is, $D(p^*, 0) < 2k_2$, then neither firm need reach its capacity constraint, and there will be a range of possible solutions to the coupled differential equations, as in figure 4. Again, following earlier arguments, one can solve for the most profitable pair of supply functions in the short run, or in the longer run take account of the threat of entry. Newbery (1991) shows how to solve the coupled differential equations analytically for the important special case of constant costs, though apart from this special case, solutions must be found by numerical integration on a computer.

In Green and Newbery (1991), we calibrated cost functions for each of the duopolists and solved for the asymmetrical equilibrium, as well as for a symmetric duopoly. We found that the differences between the two at the industry level (though not at the individual firm level) were small. In the asymmetric case, the larger firm (National Power) will gain more from any increase in the price and will therefore tend to choose a steeper supply function, relative to marginal cost, than in the symmetric case. This gives the smaller firm (PowerGen) a less elastic residual demand and a greater incentive to raise its own price in turn, partially offset because it is smaller than it would be in a symmetric world. The combined effect was to make the industry supply function steeper. The level of output was 1.3 percent lower and the price 3.8 percent higher in the asymmetric than in the symmetric base case, profits were 5 percent higher, and the deadweight losses involved were 30 percent higher. We also found that PowerGen does much better than its larger rival, National Power. The reason is that National Power submits a supply function that is much steeper relative to marginal cost than that of PowerGen: it has to do more of the work involved in keeping the price high. National Power produces more than PowerGen, but only slightly, and the greater surplus it earns over its fuel costs is more than offset by its higher fixed costs.

It is an order of magnitude more difficult to solve the pair of equations (2) for the asymmetric equilibrium than the single equation (3) for the symmetric equilibrium, and the rest of the paper will restrict attention to the symmetric case. In the asymmetric case, less output would be sold at a higher price, and industry operating costs will be further raised for any level of output since the stations will no longer operate in merit order. The estimates produced in the rest of this paper will therefore tend to understate the distortions that the generating duopoly could cause, treating it as a symmetric duopoly, rather than the unbalanced structure that presently exists.

III. Empirical Simulation of the British Spot Market

Our aim is to fit the theoretical model as closely as possible to the empirical reality of the British spot electricity market, given the decision to model it as a symmetric duopoly. The first simulations are based on the industry's position at the time of restructuring. Data on consumer demand over time were taken from figures in Electricity Council (1989), reproduced as figure 1. These gave demand over a typical winter and summer day, and an average of the two load-duration curves was used to give a third season, midyear. The "year" over which all results were summed consists of 100 "winter," 115 "summer," and 150 "midyear" days. Total demand on the system came to 242 terawatt hours (TWh), as in 1988/89. The demands in each half hour were scaled up by between 1.5 and 3 percent, representing transmission losses, to give the amount of electricity that had to be generated, some 248 TWh. The pumped storage stations, owned by NGC, were used to "lop" peaks and troughs, generating

1.8 TWh but consuming 2.5 TWh. The interconnectors with France and Scotland were assumed to provide a constant 1.8 gigawatts (GW) throughout the year, or 16 TWh in total. Nuclear power stations in England and Wales produced 6 GW throughout the winter, 5 GW in midyear, and 4 GW in the summer, to give a total of 43 TWh. The industry needs to operate some plant as "spinning reserve," fired up but not generating, in case of sudden failures. This was treated as an extra gigawatt of output in every period.

Information on costs was taken from past editions of the *CEGB Statistical Yearbook,* which gave the thermal efficiencies of each coal- and oil-fired power station. Older stations were given the thermal efficiencies that they achieved in the late 1960s, when they were running for most of the time, as better measures of the marginal fuel cost once fired up. The average coal price quoted in the generators' prospectus, 180*p* per gigajoule (GJ), together with an estimate of transport costs, was used to produce an estimate of fuel costs per megawatt hour. These ranged from £18.5/MWh to £24/MWh for the 45 GW of conventional steam plant. We estimated the cost of the 3 GW of peaking gas turbines by assuming thermal efficiencies between 18 and 25 percent, and a price of kerosene of 220*p*/GJ. A simplified cost function was required, and the following was chosen:

$$\begin{aligned} C' &= 18.5 + .1\tilde{Q}, && 0 \leq \tilde{Q} \leq 30, \\ C' &= 21.5 + .06(\tilde{Q} - 30)^2, && 30 \leq \tilde{Q} \leq 48. \end{aligned} \tag{7}$$

The marginal cost function is defined in terms of adjusted output, $\tilde{Q}$, rather than actual output, Q. The reason is that some plant is usually out of service, and so a given level of output costs more to produce than if the whole plant were available. We assumed that 90 percent of the plant was available during the winter and used $\tilde{Q} = Q/.9$. In the summer, 70 percent of the plant was available, and 80 percent during the midyear season. The chosen marginal cost function slopes much more steeply at high output than is calculated from the operating cost data, and this reflects the shorter times for which the peaking plant operates: the pool price at these times is raised by the plants' start-up charges, spread over their output. The model cannot accommodate this method of calculating prices, but the higher marginal costs produce a similar result. Figure 5 gives the estimated fuel costs for each generating set in merit order, with the most efficient peaking gas turbines coming in at £35/MWh and the function described in (7) showing the fit to the data. The cost function appropriate to any firm is found by multiplying the adjusted output $\tilde{Q}$ by the number of firms, n.

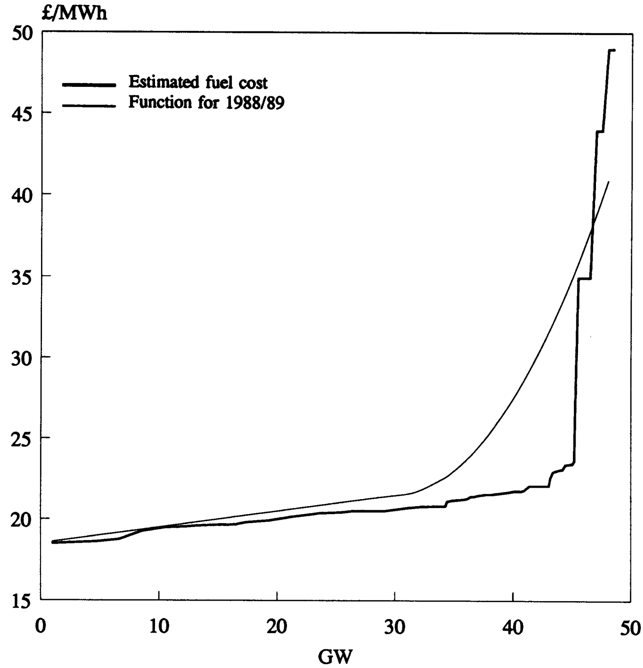

FIG. 5.—Generating costs for conventional stations, 1988/89

The base case assumed that the price in each half hour was the marginal cost in that half hour, using the function above. Demand was assumed to take the simple form $D(p, t) = a(t) - bp$, so that $D_p = -b$ in equations (2)–(6). The price-output pairs and three alternative values of the slope parameter, b, were used to calculate the intercepts of the demand curves used. They gave a total revenue from the pool of £5.5 billion, or an average price of £23/MWh. The CEGB's bulk supply tariff for 1988/89 split its income into nonmarginal charges, predetermined for each area board, capacity charges based on peak demand levels, and unit running rates. The income from running rates came to £20.8/MWh, below our figure. In the 1988/89 accounts, however, a large part of the income from the nonmarginal charge was grouped with the running rates as "energy income," and this averaged £27.1/MWh. These bracket our figure, which is in line with average pool prices observed in the first half of 1991. The contracts presently fixed between the generators and suppliers appear to include net payments to the generators, corresponding to capacity charges. We have assumed that these payments would continue and would exceed the duopolists' fixed costs by £375 million per year. That is the amount that must be added to their surplus of pool revenue over fuel costs (when pricing at marginal cost) to give their actual operating profit in 1988/89.

The prices in our model do not vary as much as those observed from the pool, for a number of reasons. By using typical days for our demand curves, we miss the highest and lowest demands, which would tend to produce the most extreme prices. We do not include the start-up charges, which can produce high prices for quite modest daily peaks (although the marginal cost curve has been shifted upward); nor do we deduct them when demand is low (in the so-called table B periods). The generators' incentive to raise prices is greatest when most of their plant is operating, and if demand in our simulations never reaches the highest levels actually observed, then we are excluding the times in which the exercise of market power might be most damaging. The incentive to raise prices does not differ nearly as much between our average low demands and the lowest ones, and so we do not introduce a serious bias by ignoring them. Overall, we are confident that the averaging in our model has the effect of understating the possibilities for abusing market power and the costs of doing so.

Table 1 shows the effect of moving from marginal cost pricing to the lowest-supply, highest-price equilibrium. Our central case uses a demand parameter $b = .25$, and the generators choose supply functions that nearly double the average price of electricity to suppliers and would add 50 percent to its final price. Total output falls by more than 10 percent, from 248 TWh to 214 TWh, and this implies a loss of consumer surplus of more than £300 million per year. The duopolists' revenue rises to £6,371 million, giving them an operating surplus of £3,664 million, compared to £816 million in the base case. When the deadweight triangle of producer surplus (lost by producing at below the optimal output with a rising marginal cost) is included, the total loss to society comes to £340 million per year, equal to 6 percent of total industry revenue selling at marginal cost.

Table 1 also gives the corresponding results for two other values of the demand slope parameter, b. Although there is some uncertainty about the correct value for the elasticity of demand for electricity, the range of parameters considered, .1, .25, and .5 (and their implied levels of elasticity at marginal cost and the market price, shown in the tables), almost certainly bracket the correct value. The reduction in output caused by the exercise of market power is almost identical in the three cases. In this study, the greatest reduction occurred with a parameter of .5, the most elastic case.[6] The price

[6] In Green and Newbery (1991), using slightly different demand and cost data, we found the opposite result: the greatest reduction in output came from the most inelastic demand, although the reductions were similar, ranging from 34 TWh to 40 TWh.

TABLE 1

SOLUTIONS TO THE POOL MODEL FOR 1988/89

	ACTUAL 1988/89	MARGINAL COST PRICING	QUINTOPOLY	DUOPOLY		
	(1)	(2)	(3)	(4)	(5)	(6)
Slope of demand schedule *b*			.25	.10	.25	.50
Elasticity:						
At marginal cost			.21	.08	.21	.42
At equilibrium			.24	.25	.40	.64
Price strategy of incumbents			high	high	high	high
Production (TWh):						
System energy required	248	248	241	215	214	213
Oligopoly output*	189	189	182	156	155	154
Oligopoly capacity utilization (%)	45	45	43	37	37	37
Average price (£/MWh)†	20.8‡	23.0	27.0	66.7	41.1	32.3
Deadweight losses (£m) consumer		0§	17	733	312	161
Total deadweight loss (£m)		0§	20	761	340	190
Operating surplus (£m):# Duopoly total	816	816	1,567	7,798	3,664	2,247

* The duopoly or quintopoly. Output includes 8.76 TWh of spinning reserve.
† The pool output price, including the cost of spinning reserve.
‡ Energy income plus system service charge less nonmarginal charges over output.
§ Definitionally zero, taken as the reference level.
\# Revenue plus nonmarginal payments less operating costs before capital charges.

increases required to produce the reduction in demand naturally differed greatly between the cases, and profits and deadweight losses were by far the greatest in the most inelastic case.

We have not yet observed price increases of this magnitude, at least until September 1991. During this period, most electricity sales were covered by contracts that hedged the pool price, so that a generator would not affect its short-run revenues by raising its bids. In the medium term, we might expect new contracts to be based on expected pool prices. The present contracts were supervised by the Department of Energy and were based on costs, especially the cost of U.K. coal. If generators can raise pool prices in the absence of contracts, we would expect them to sign contracts based on these higher prices, if at all. Green (1991*a*) discusses some recent bids and shows that although most have been low, a few are clearly well above cost. Once the present contracts expire, their successors are unlikely to keep prices down.

These results are extremely disturbing. If the generators were not concerned about entry (considered below) or about the regulator's response, they could earn extremely large profits while creating large deadweight losses in a market based on price competition that was intended to keep prices close to marginal costs. One regulatory response might be to attempt to control the prices bid, to impose something closer to marginal cost pricing, but this is unlikely to be easily workable. If a structural remedy exists, it could well be preferable. The pool provides relatively good incentives for the owners of single generators,[7] but there are economies of scale in pooling plant spares and specialized maintenance skills that might make larger companies desirable. We solve our model for an industry made up of five identical firms. There are four 2,000-MW and one 1,000-MW oil-fired power stations and the equivalent of ten 2,000-MW coal-fired stations[8] in England and Wales, so this proposal is consistent with the industry's actual capital stock. National Power would be divided into three equal-sized firms and PowerGen into two. Firms with 10 GW of capacity, producing about 40 TWh per year, would be within the flat portion of the cost function derived by Christensen and Greene (1976).[9]

[7] Von der Fehr (1991) studies these incentives in an auction model. With pool prices based on the marginal set's own bid, there is an incentive to bid above marginal cost (although this might well be small in a large market when each set is only briefly at the margin). A minor change in the pool rules, to create a second-price auction, would eliminate this incentive.

[8] That is, eight 2,000-MW stations and the 4,000-MW station at Drax. The three other stations with 500-MW sets and the 27 smaller stations could be apportioned to give a good geographical spread and equal total capacities.

[9] Using 1970 data, they found no significant scale effects for outputs between 19.8 TWh and 67.1 TWh per year, and a cost minimum at 33 TWh. Their study was based

Column 3 (headed "quintopoly") of table 1 shows that this restructuring lowers the reduction in output from 13 percent to 3 percent, and the increase in average price is £4 rather than £18. A firm that produces less has less incentive to raise the price and will tend to submit a more elastic supply function. The other firms face a more elastic residual demand, which reduces their incentive to raise prices. The equilibrium price is significantly lower, and since deadweight losses are typically related to the square of a distortion,[10] it should not be surprising that they are reduced from £340 million to £20 million. The five firms' surplus also rises by much less, to £1,567 million, less than half the duopoly surplus. Once again, the reduction in output is almost the same for all three values of the demand parameter (not shown in the table). This restructuring seems to produce a much more attractive outcome. In the absence of restructuring, the key question to address is whether entry can introduce adequate competition in the medium run to reduce these inefficiencies.

IV. Entry

The electricity pool is certainly not a contestable market. Incumbents can change their prices every day, whereas CCGT power stations, the entrants' preferred technology at present, take 2 or 3 years to build and commission. Once built, their costs are largely sunk, and so "hit-and-run" tactics are inconceivable. In 1991, British Gas attempted to restrict the amount of gas taken by new generating projects because of a perceived shortage of supplies in the U.K. sector of the North Sea. This restriction could be avoided if the government allowed large-scale gas imports. A large number of firms are attempting to build new capacity, and others might enter if the pool price were forecast to remain at high levels. We do not attempt to study the dynamics of entry but look for Nash equilibria in incumbents' supply functions and levels of additional capacity.

To do this, we rebased the model to 1994/95, far enough in the future to allow significant entry but close enough to allow continuity in our assumptions. Consumers' demand in every period was raised by 10 percent from the base level, following NGC's *1991 Seven Year Statement.* The French and Scottish interconnectors were assumed to supply an extra gigawatt of output, as a result of more intensive use and a planned increase in the capacity of the Scottish interconnector.

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on technology similar to that presently in use in most U.K. plants. If the least-cost range of output has shifted over time, it is so large that a 40-TWh firm should still be within it.

[10] See Newbery (1990) for a discussion of the relation between deadweight loss and the number of firms in an oligopoly.

Nuclear output was raised by 10 percent: the pressurized water reactor at Sizewell B should be commissioned and Nuclear Electric may be able to improve the (dismal) performance of its advanced gas-cooled reactors, but it may also have to close some more of its old Magnox stations. All input prices were held at the same levels as in the base case. The duopolists were assumed to have replaced 4 GW of old coal-fired plant by new CCGT plant, as announced in their prospectuses. The cost function used was therefore amended to give

$$\begin{aligned} C' &= 16, && 0 < \tilde{Q} \leq 4, \\ C' &= 18.1 + .1\tilde{Q}, && 4 \leq \tilde{Q} \leq 34, \\ C' &= 21.5 + .6(\tilde{Q} - 34)^2, && 34 \leq \tilde{Q} \leq 45, \\ C' &= 21.5 + .06(\tilde{Q} - 30)^2, && 45 \leq \tilde{Q} \leq 48. \end{aligned} \tag{8}$$

Figure 6 graphs (8) and compares it with the earlier cost function (7), showing that over most of its range it is a horizontal displacement by 4 GW of equation (7), with CCGT coming in at £16/MWh and the final 3 GW of peaking plant unaffected.

Entrants were assumed to build CCGT stations, with a fuel cost of

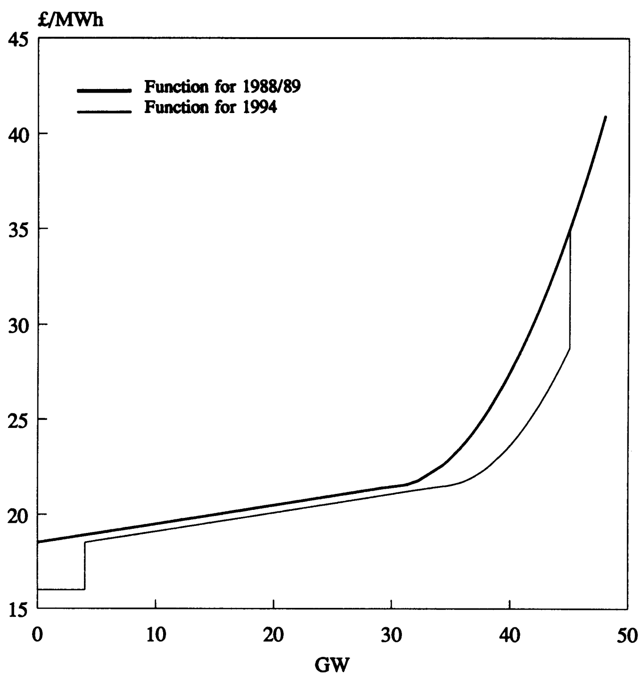

FIG. 6.—Generating cost functions for conventional stations

£16/MWh,[11] other running costs of £20/kW a year, and an initial capital cost of £400/kW. The capital cost was depreciated over 20 years, with an interest rate of 15 percent, giving an annual charge of £64/kW and a total cost to be covered by their operating surplus of £84/kW a year. They were assumed to have the same availabilities as the duopolists and to bid in their plants at marginal cost, since no independent entrant would be large enough to gain from setting a higher price. This normally meant that the entrants operated on baseload. The equilibrium level of entry is the one that gives each entrant an operating surplus over fuel costs of £84/kW, just covering their other costs, given the actions of the duopolists.

The basic equilibrium for this version of the model was calculated on the assumption that there would be 3.2 GW of independent entry (the projects reported in NGC's 1991 statement). The outputs derived above were matched with the marginal costs calculated for those outputs to give the demand intercepts for each period, and the duopolists' supply functions were used to find the market equilibria for varying levels of entry. Columns 4–6 of table 2 show the equilibria in which the duopolists choose their highest-output, lowest-price supply functions, which yield the incumbents the highest sustainable profits given free entry.

In the central case, with $b = .25$, a further 4.8-GW plant (in addition to the forecast entry of 3.2 GW) is built before the average price equals the entrants' average costs. The duopolists do produce some electricity in every period, but a much smaller proportion of the total than before. The duopolists earn an operating surplus of £1,851 million. Output is lower, at 258 TWh, but the lower fuel costs of the additional CCGTs produce a gain in producer plus consumer welfare of £80 million a year, before the cost of the extra investment is considered. If the gross social cost of investment is 10 percent of the capital value per year, then each gigawatt of extra capacity will cost £60 million a year in capital charges and other running costs. With an additional 10 GW of capacity, this produces a net loss in social welfare of £208 million a year.

Alternative values of the demand parameter produce very different levels of entry since the amount of extra output required to bring the average price down to the entrants' costs depends on b. In the most elastic case, the entrants would provide only 2.6 GW of capacity (compared to forecast additions of 3.2 GW, suggesting that this is an implausibly high estimate of the demand elasticity), and the total loss to society is £112 million. In the most inelastic case, the entrants

[11] This can be obtained with a thermal efficiency of 45 percent and a gas price of 21p per therm.

TABLE 2

SOLUTIONS TO THE POOL MODEL FOR 1994

	MARGINAL COST PRICING	QUINTOPOLY	DUOPOLY			
	(1)	(2)	(3)	(4)	(5)	(6)
Slope of demand schedule *b*		.25	.25	.10	.25	.50
Elasticity:						
At marginal cost		.18	.18	.07	.18	.36
At equilibrium		.22	.24	.10	.25	.52
Price strategy of incumbents		high	high	low	low	low
Entry (GW)	3.2*	0	13.5	11.2	8.0	2.5
Production (TWh):						
System energy required	273	264	258	267	258	243
Incumbent output†	188	201	101	126	139	162
Entrants' output	22	0	94	78	56	18
Incumbent capacity utilization (%)	45	48	24	30	33	39
Average price (£/MWh)‡	21.7	26.7	30.1	29.9	29.8	29.7
Deadweight losses (£m) consumer	0§	27	78	26	62	119
Consumer plus producer	0§	138	−206	−212	−80	150
Total deadweight loss (£m)	0§	−54	412	268	208	108
Operating surplus (£m):#						
Incumbent total	739	1,715	1,609	1,775	1,847	1,992
Entrants per GW capacity	34	64	84	84	84	84

* Forecast entry, not the efficient or equilibrium level.
† Plant of National Power plus PowerGen divided into two or five firms. Output includes 8.76 TWh of spinning reserve.
‡ The pool output price, including the cost of spinning reserve.
§ Definitionally zero, taken as the reference level.
\# Revenue plus nonmarginal payments less operating costs before capital charges.

would still earn supernormal profits if they provided all the conventional baseload electricity, and the duopolists provided only the marginal output. This would require at least 11.2 GW of total entry, and the associated deadweight losses come to £269 million per year. In all three cases, the cost of the last unit of additional entry is greater than the reduction in fuel costs and consumer losses that result, and so there is "too much" entry, even given the generators' strategies.

Table 2 presents two other sets of results. Column 3 shows the effect when the incumbents coordinate on the high-price supply function, which yields the highest short-run profits but induces the most entry. The central case has entry of 13.5 GW instead of 8.0 GW with the low-price strategy and yields incumbent profits of £1,610 million instead of £1,851 million. Social costs are twice as high. Finally, column 2 gives the worst case (high-price equilibrium) if the industry had been divided into five equal-sized firms. Their pricing strategy would not induce any entry, and the outcome is better by £54 million than the reference case of marginal cost pricing but with presently forecast entry levels. Consumers pay lower prices, but profits are higher than with a short-run profit-maximizing duopoly subject to entry. The results are remarkably insensitive to the bidding strategy of the quintopolists: they earn only 7 percent less, and deadweight losses are £6 million lower with the lowest-price Nash equilibrium strategy than with the high-price strategy.

V. Conclusions

In the short run the strategies followed by National Power and PowerGen will have little effect on the level of entry, and in this period they have very considerable market power, which they can exercise without collusion by offering a supply schedule that is considerably above marginal operating cost. They have additional methods of market manipulation that exploit the constraints on the grid's transmission capacity, since their market power in some of the regional submarkets is considerably greater than in the country as a whole. They doubtless have further opportunities to manipulate the market through the other components of the bids submitted, such as the cost of start-up, quite apart from the possibility of supporting more collusive outcomes in the repeated game.

In the medium run, considerable entry is already planned and is a logical response to the likely market equilibrium, though our calculations suggest that the forecast level of capacity expansion is not justified on social cost benefit grounds. If the incumbents can commit to a high-supply, low-price strategy after entry, they will deter more entry and earn higher profits than if they attempt to coordinate on the high-price, short-run profit-maximizing strategy. Even so, total deadweight loss is £262 million higher than if the industry had been divided up into five equal-sized firms, in our central case of the demand elasticity and our optimistic assumption that the incumbents act as a symmetric duopoly. Even though entry will cause the incumbents to set lower prices, considerable social loss is caused by the large and unnecessary induced investment in additional capacity.

Our analysis suggests that the scope for the exercise of market power has been seriously underestimated by the government, perhaps misled by the notion that Bertrand competition is necessarily very competitive, even in concentrated markets. The potential deadweight losses are high, both on the demand side and on the cost side as a result of departures from the efficient merit order.[12] How high these losses will be will depend on the extent to which the generators attempt to maximize short-run profits in the period before entry and the amount of excess entry that is attracted into the industry. The generators could coordinate on the lowest-price Nash equilibrium strategy, but even in this case deadweight losses are considerable. Almost all these inefficiencies could have been avoided by subdividing the industry into five equal-sized rather than two unequal thermal generators. Nor is it clear that the administrative complexities of arranging such a sale would have been much greater than that involved in creating six rather than the three successor generators, for the main extra difficulties arose in moving away from the original single company. There appeared to be no great difficulty in privatizing the 12 area boards. One is forced to conclude that a great opportunity to move to a competitive and unregulated supply industry was lost. Whether it is better to move to a U.S. style of regulating the generators to keep prices low enough to deter unwanted entry or whether it is better to accept this extra cost in the hope of moving to a more competitive industry that does not require regulation remains an interesting and open question.

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[12] These additional costs arise only in the asymmetric case, discussed in Green and Newbery (1991), and have been ignored here. They are about 1 percent of operating costs.

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