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ABSTRACT

This paper considers the bidding behavior of participants in the daily auction to supply electricity in England and Wales. Every day, owners of generating capacity submit bids reflecting a price for power from their plants. The price bid by the last plant used to meet electricity needs in a given time period is the price paid for capacity from all plants. Theoretical work on uniform-price multi-unit auctions suggests that bidders selling more than one unit of a good have an incentive to increase the prices they bid at high quantities. If a bid sets the equilibrium price, the bidder receives a higher price for that unit as well as for all inframarginal units. I find evidence of strategic bid increases. First, plants that are likely to be used after a number of other plants are already operating bid more. Second, the larger supplier submits higher bids, all else equal. Lastly, there is some evidence that bids for given plants are higher when the suppliers have more available capacity.

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1. INTRODUCTION

Multi-unit auctions have attracted considerable attention lately as several prominent auctions, most notably the FCC sale of spectrum rights, have involved the sale of multiple units of a good. The recently-created competitive market for electricity generation in England and Wales is organized around a daily auction where the "good" that is sold is the right to be paid to supply power in a given time period. Since meeting electricity demand always involves power from a number of plants, the electricity auction always involves multiple units. Moreover, as most owners of generating capacity control more than one plant, they are awarded multiple "goods" through the auction. In this paper, I appeal to the theoretical auction literature for characterizations of bidder behavior and market outcomes in multi-unit auctions, and then evaluate the extent to which these predictions hold empirically in the daily electricity auction in England and Wales. As there are comprehensive data and information on the electricity auctions, they provide a unique environment for considering characteristics of multi-unit auctions. In addition, since the auction in England and Wales is being considered as a model for electricity industry restructurings elsewhere, it is particularly important to understand the behavior of participants in this auction.[1]

The theoretical auction literature has addressed multi-unit auctions in two ways. First, a number of articles have shown how, under certain assumptions, the main results concerning single-unit auctions extend to the multi-unit context (see *e.g.*, Harris and Raviv, 1981 or Weber, 1983). A second set of articles has sought to differentiate multi-unit from single-unit auctions and identify unique characteristics of the former (see *e.g.*, Wilson, 1979; Back and Zender, 1993; Ausubel and Cramton, 1996; and Tenorio, 1997). I test several implications from the second group of articles.

[1] See Joskow (1996) for a discussion of the issues associated with designing competitive electricity markets and some of the market structures implemented and proposed in various venues.

A distinguishing feature of some multi-unit auctions is that bidders are allowed to relate the price they are willing to pay to the number of units they are awarded. In other words, bidders are allowed to submit a bid function rather than a single price. The amount bidders pay depends on whether the auction is discriminatory, in which case bidders pay the amount they bid for each unit, or uniform-price (also called "competitive") in which case bidders pay the market-clearing price for every unit they are awarded. In a uniform-price multi-unit procurement auction, bidders have an incentive to overstate their costs associated with providing a large quantity of the good or service (*i.e.*, submit a steeply increasing bid function) (see Wilson, 1979; Back and Zender, 1993; and Ausubel and Cramton, 1996). If a suppliers' bid becomes marginal and sets the equilibrium price, he will be paid a higher price for *all* the units he is awarded. I find evidence of strategic bid increases in the electricity auction in England and Wales.[2]

The existing empirical literature on auctions is vast, presumably motivated by the rich information available from auctions and the extensive theoretical treatment of them. Empirical papers have analyzed markets for goods such as offshore oil rights, timber and eggplants (see *e.g.*, Porter, 1995; Paarsch, 1991 and Laffont, Ossard and Vuong, 1995, respectively). With the exception of several studies of auctions for financial instruments (Tenorio, 1993, Umlauf, 1993, Simon, 1994 and Nyborg and Sundaresan, 1996) and a recent analysis of the FCC spectrum auctions (see Ausubel and Cramton, 1996), all of the existing empirical literature considers single-unit auctions.[3]

Moreover, the analysis in this paper has several advantages over the other studies of multi-unit auctions. Both Umlauf's (1993) study of Mexican Treasury bill auctions and Tenorio's (1993)

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[2] I use "strategic bidding" to describe bidding above marginal cost in order to set a higher price for inframarginal capacity. Note that it does not necessarily involve interactions between bidders.

[3] Holt, Langan and Villamil (1986) find experimental evidence that sellers with inframarginal capacity submit steeper bid functions in order to drive up the marginal price. They find that strategic bid increases are particularly pronounced with subjects who are experienced with the experimental setup for their oral double auctions.

study of Zambian foreign exchange auctions compare periods in which the financial authorities used discriminatory auctions to periods in which uniform-price auctions were used. They evaluate whether the bids submitted in the two formats correspond with theoretical predictions. However, both studies also conclude that the different outcomes across the two formats could have been driven by the fact that bidder participation and/or the degree of collusion between the bidders were affected by the change in format. By contrast, in this paper, I analyze over 500 daily repetitions of the same auction involving the same bidders and am able to consider the effects of exogenous differences between the bidders and exogenous differences in the units for which they are bidding.

Simon (1994) and Nyborg and Sundaresan (1996) focus on differences between discriminatory and uniform-price auctions generated by informational asymmetries across bidders. (For instance, theory suggests that the winner's curse will restrain bidding more in discriminatory auctions than in uniform-price auctions.) As I will argue below, information on the costs of the bidders in the electricity auctions (in other words, information on their valuations) is readily available both to outside observers and to other bidders. As a result, my analysis can isolate the strategic incentives created by bidders' inframarginal capacity from any informational issues associated with the auction format. In addition, my measure of bidders' valuations is less problematic than the rates from when-issued markets used in studies of the US Treasury auctions. (See Nyborg and Sundaresan (1996) for a discussion of some of the problems with when-issued rates.)

Ausubel and Cramton (1996) consider evidence from the FCC spectrum auctions involving simultaneous sales of spectrum rights in different regional markets. They characterize the bidders either as having "strong regional interests" or as being "value seekers" and show that bidders of the first type paid more for the units they bought. They interpret that as evidence that the participants were bidding strategically, claiming that the strong regional bidders reduced their demand in some markets in order to accommodate the value seekers and prevent them from driving the price up in all markets. Although theirs is a highly plausible explanation for the observed bidding behavior (and is corroborated by the authors' communication with companies' bidding strategists), Ausubel and Cramton cannot refute the alternative interpretation that the strong buyers paid high prices for the units they valued the most leaving other units for the value seekers to purchase at prices that were lower but still above the strong buyers' valuations. Because I am able to measure the electric generating companies' marginal operating costs, I am able to use direct measures of the value of bidding a certain amount. In addition, while Ausubel and Cramton only test strategic bidding by analyzing patterns across bidder types, I am able to test several manifestations of strategic bidding.

Consistent with Ausubel and Cramton's results, I find evidence that the largest participant in the electricity auctions in England and Wales bids considerably more than its smaller competitor for units with comparable costs. I also find that the suppliers submit bids reflecting a larger markup over marginal costs for plants that are more likely to be used after a number of other plants are already operating (*i.e.* when there is more inframarginal capacity). Third, I find some evidence that the suppliers submit higher bids for given plants on days when more of their units are available to operate.

The remainder of this paper is organized as follows. In the next section, I will describe the daily electricity auctions in England and Wales. Section three considers the theoretical literature on multi-unit auctions, focusing on analyses with particular relevance to the UK electricity auctions. Section four begins by laying out three empirical implications of the theoretical literature, and then presents results of tests of the predictions based on data from England and Wales during the years 1992 to 1994. Section five concludes.

2. THE DAILY ELECTRICITY AUCTION

When the British government privatized and restructured its electricity industry in April 1990, one of the most significant steps it took was to introduce competition into the generating sector of the industry.[4] The government created a spot market for wholesale power in which generating companies compete to sell their power and from which all wholesale customers buy power. The auction mechanism used to establish the spot market or "pool" prices is the subject of this paper. In this section, I first describe the generating companies that participate in the pool and then describe the mechanics of the auction.

During the first five years following privatization, two companies, National Power and PowerGen, owned the majority of the generating capacity in England and Wales. They were therefore the primary suppliers to the spot market.[5] Together they owned approximately 70 percent of the country's total capacity, though National Power was considerably bigger than PowerGen. Just after the restructuring, National Power owned plants capable of providing roughly 30 gigawatts of power while PowerGen's plants supplied 20 gigawatts. In the five years following the restructuring, however, both National Power and PowerGen retired old plants and added new plants for net capacity reductions of approximately 9.5 and 2.5 gigawatts, respectively.[6] All of National Power and PowerGen's plants burn fossil fuels.

The other major supplier to the pool during its early years was Nuclear Electric, the company which owned all twelve of the nuclear power stations in England and Wales. Nuclear Electric was left in the public's hands at the time of the industry privatization, but portions of it were privatized in

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[4] See Vickers and Yarrow (1991) and Armstrong, Cowan and Vickers (1994) for overviews of the changes and Newbery and Pollitt (1997) for an appraisal of its early effects.

[5] While the introduction of a competitive generating sector was applauded, the duopoly structure that the British government created has been harshly criticized. There is considerable concern that National Power and PowerGen have taken advantage of their market power to inflate pool prices. Wolfram (1996), however, finds that pool prices are not nearly as high as economic models of the market predict they could be.

[6] In March of 1994, the industry regulator directed both National Power and PowerGen to dispose of approximately 15 percent of their capacity. To comply, both generators leased plants to one company, Eastern Electricity, a subsidiary of the Energy Group PLC. The deals were not completed until 1996.

1996.[7] When the newest nuclear reactor, Sizewell B, became operational in the beginning of 1995, it added one gigawatt to Nuclear Electric's existing nine gigawatts of capacity. Power supplied through connections with Scotland and France and by two pumped storage facilities[8] consistently provided several additional gigawatts. In the five years after March 1990, approximately five gigawatts of new capacity, all using combined-cycle gas turbine (CCGT) technology[9], were added by independent power producers.

Though National Power and PowerGen's plants only accounted for approximately two-thirds of the country's total generating capacity, during the time period I consider they were the marginal supplier over 90 percent of the time. Primarily, that was a function of the operating characteristics of the two companies' plants. Nuclear and CCGT plants both have low operating costs and thus are operated as "baseload" units, meaning they are run almost constantly. Much of the capacity in France is also nuclear, and power from Scotland is predominantly generated using hydroelectric dams. Since hydroelectric power has extremely low operating costs, those sources also provide baseload capacity. National Power and PowerGen's coal and oil facilities, especially some of the older and smaller plants, are more expensive than the baseload units. Their gas turbines are much more expensive and only designed to run at peak times. As a result, National Power and PowerGen's fossil-fuel plants frequently provided the marginal capacity.

[7] In the beginning of 1996, a company called British Energy was formed comprising nine of Nuclear Electric's newer plants and Scottish Nuclear's two plants. Stock in British Energy was floated in the summer of 1996.

[8] Directly after the privatization, the pumped storage facilities were owned by the National Grid Company, the company that owns and operates the transmission grid. In late 1995, the two facilities were sold to Mission Energy, a subsidiary of the California utility holding company, Edison International.

[9] CCGTs recover waste heat produced when gas is burned to drive conventional turbines and use it to heat steam to power another turbine. They are highly efficient, converting approximately fifty percent of the energy content of gas to electricity, while conventional coal or oil-fired stations convert thirty to forty percent of the energy to electricity.

The pool's primary customers are the twelve Regional Electric Companies (RECs) which have local monopoly franchises on electricity distribution in various regions of the country. Most of the end-use customers to whom the RECs distribute and re-sell electricity are on annually fixed tariffs that do not vary with the daily or hourly pool price fluctuations. The demand from those customers is, at least in the short run, inelastic to changes in pool prices. Large customers, however, are allowed to choose their wholesale suppliers.[10] Candidate suppliers (called "second-tier suppliers") include the local REC, other RECs, the generators and several independent brokers. The suppliers arrange to acquire power from the pool and then re-sell it to the end-use customers. (The local REC still provides distribution services to the large customers.) Some of the large customers sign contracts with their suppliers that closely link the prices they pay to pool prices. Those customers have an incentive to monitor pool prices quite closely and adjust their consumption accordingly. Total pool demand, therefore, is not completely inelastic to the equilibrium pool price.

A large fraction of the suppliers' pool purchases are covered by financial contracts with the generators. The contracts (know as Contracts for Difference or "CfDs") are based on a strike price. The buyer nominally pays the spot pool price, but if the pool price is above the strike price, the generator compensates the customer with the difference. If it is a two-way CfD, the exchange is reversed when the pool price is below the strike price. Separate contracts can cover different times of the day or of the year and can be tied to different types of plants. At privatization, the government set up CfDs between the RECs and National Power and PowerGen which were in effect for from one to three years. Since then, the generators and the RECs have negotiated replacement contracts.

Administratively, the pool is a separate legal entity and its membership comprises all of the generating companies, the RECs, the independent brokers and a few large customers. In order to buy

[10] Customers with annual maximum demand greater than one megawatt were allowed to choose a supplier in March 1990, those with demand greater than 100 kilowatts could choose in March 1994, and all customers are scheduled to be able to choose in March 1998. Until 1998, small customers are served by the local REC.

or sell power through the daily spot market, a party must pay a nominal fee and agree to a set of administrative rules (the "Pooling and Settlement Agreement"). Pool operations are administered by the National Grid Company, which develops and publicizes the prices, oversees dispatching, arranges financial settlements between the parties and arbitrates billing disputes.

Mechanically, the pool works as follows. Every day by 10:00 AM, each generator submits a schedule detailing the prices at which it would be willing to supply power on the following day. The schedule consists of separate bids for each "generating unit" the company owns. The generating units, ordinarily corresponding to one turbine within a plant, vary in size between less than 20 and more than 600 megawatts. There are between 2 and 11 generating units per plant. The bids for each unit have several elements. First, the generator indicates whether or not the unit will be available to produce electricity and, if so, how much. Pool rules forbid companies from declaring all of a unit's capacity as available directly following an outage at the plant, but generally, companies are free to choose the quantity they wish to provide. The generator also submits various technical characteristics of each unit including the ramp-up time, the flexibility the unit has to generate at less than full capacity and the number of times a day the unit can be turned on and off.

On the pricing side, bids include a rate for starting to produce electricity from the unit (the "startup" price expressed in £s per start), a rate for keeping the unit warm regardless of the amount of electricity generated (the "noload" price expressed in £s per hour), and up to three rates for the electricity generated from the unit (the "incremental" prices expressed in £s per megawatt-hour). The generator specifies the ranges over which the increments apply by submitting the endpoints of each range ("elbow points"). In a plot of bid price (measured in £s per hour) versus quantity supplied (measured in megawatts), the noload price is the intercept and the incremental prices allow the slope of the function to vary between elbow points.

The pool administrator combines the bids from all of the generators. For each generating unit, he calculates the bid price as a function of output from the unit according to the following formula:

$$Price = \begin{cases} \dfrac{Noload + Inc1 * Elbow1 + Inc2 * (Elbow2 - Elbow1) + Inc3 * (Output - Elbow2)}{Output} & \text{if } Elbow2 < Output \\ \dfrac{Noload + Inc1 * Elbow1 + Inc2 * (Output - Elbow1)}{Output} & \text{if } Elbow1 < Output < Elbow2 \\ \dfrac{Noload + Inc1 * Output}{Output} & \text{if } Output < Elbow1 \end{cases} \quad (1)$$

In the end, therefore, the pool condenses the generators' bids to a single number, and does not use the separate components.[11]

All of the pricing information is then merged with demand forecasts for each of the forty-eight half-hour periods on the following day. The demand and price information is then run through a complex optimization program that develops a schedule for dispatching plants in order to meet demand over the following day at the lowest cost. Essentially, the program chooses the units with the lowest bids in any given period, though some intraday optimization takes place. For instance, given restrictions on re-starting plants, it might be cheaper to accommodate a short-term dip in demand by asking a number of units to reduce capacity rather than by shutting one unit down completely and later re-starting another one. When the hypothetical dispatch pattern is developed, the startup price is divided between the periods during which the plant will run.[12] The administrator then determines a

[11] After the auction rules specifying the bid structure were implemented, the market designers realized that the optimization program (the program is called GOAL - General Ordering And Loading) was unstable if all the pieces of the bid were used. One problem was that it yielded multiple equilibria.

[12] In certain periods, called Table B periods, the prices do not reflect startup or noload costs, but are simply the incremental bid over the appropriate range. Periods are categorized as Table B when the difference between scheduled capacity and forecast system demand is greater than a certain threshold.

System Marginal Price (SMP) for each of the forty-eight half-hour periods in the following day as the bid price for the last plant needed to meet demand.[13] Note that although a separate price is set for each of the forty-eight half-hour periods, the generators only submit one bid a day for each generating unit. The SMP still varies significantly within a day because units with different prices are marginal at different times of the day.

The prices that customers actually pay and that the generating companies actually receive have several additional components, some of which potentially could influence the generator's bidding behavior. For one, there is an additional factor that is designed to compensate the generators for making their capacity available. The value that the pool assigns to availability is based on the probability that there would be insufficient supply to meet demand (the Loss of Load Probability or LOLP) and the value to customers of avoiding a power loss (the Value of Lost Load or VLL). At the time of the restructuring, the government set the VLL at £2,000 per megawatt-hour (compare this to an average pool price of approximately £25 per megawatt-hour during 1990) and every year it is increased at the rate of inflation. LOLP is based on the difference between forecasted demand and available plant. It is a small number and can be zero. The total pool price (or pool purchase price, PPP) including the capacity payment for a given period t is calculated as:

$$PPP_t = SMP_t + LOLP_t * (VLL - SMP_t).$$

The capacity payment may provide the generators with an incentive to limit the number of units they declare as available, as LOLP is inversely related to available capacity (see Wolak and Patrick, 1996).

The original PPP is calculated assuming that plants will be called upon to meet demand in order of their bid prices. In fact, plants may be operated out of order because of transmission

[13] Since the plant that sets the price is actually the last plant that will supply electricity in a particular period, this is a first-price auction. If the next plant to be called set the price, it would be a second-price auction.

constraints. If a unit that was not originally scheduled to operate, that is a unit whose bid price exceeds the SMP, is needed in order to alleviate transmission congestion (is "constrained-on"), pool rules require that it be paid its bid price. As a result, the suppliers have an incentive to submit high bids for plants that are likely to be constrained-on (see OFFER, 1992). Adjustments due to transmission limitations are captured by a fee called Uplift, and the price that the pool customers pay, the Pool Selling Price (PSP) is equal to Uplift plus the PPP. The PPP is also calculated using forecasted demand. After demand is realized, adjustments are made to both generators' revenues and to Uplift to reflect differences between the actual and forecasted demand. Last, generators receive payments for what are called "ancillary services" which involve, for instance, providing spinning reserves or reactive power capacity. Payments for ancillary services are also collected through the Uplift charge.

3. THEORETICAL FRAMEWORK

In this section, I consider implications of the existing theoretical literature on multi-unit auctions for the electricity auction in England and Wales. Results from some articles have limited applicability because the assumptions made do not coincide with the institutional setting of the electricity auction described above. For instance, several papers are able to generalize many of the results on single-unit auctions by considering auctions where the bid-taker is offering more than one unit but where bidders demand at most one unit (see *e.g.*, Harris and Raviv, 1981; Weber, 1983 and the beginning of Maskin and Riley, 1989). Clearly that characterization is not germane to the British electricity auction because the three major bidders, National Power, PowerGen and Nuclear Electric, are paid for power from a large number of plants. Nautz (1995) derives optimal bidding functions for bidders with continuous demands, but assumes that there are a large number of price-taking bidders. In other words, he assumes bidders do not believe their bids will affect the equilibrium price. Given the small number of generating companies in Britain and the fact that only two of them, National Power and PowerGen, set the price most of the time, Nautz' assumption is unrealistic for the electricity auction.

Several articles have addressed the incentives for strategic bid manipulations created by multi-unit auctions. Back and Zender (1993), inspired by the Treasury's decision to switch from a discriminatory (pay-your-bid) to a uniform price (pay the equilibrium bid) format for government securities, compare bidding behavior in the two settings. They consider an environment where bidders are allowed to submit a demand curve, or schedule of prices they would be willing to pay for various quantity levels. They show how bidders will want to understate their value for large quantities (offer a steep demand curve) in a uniform price auction but will have no such incentive in a discriminatory auction. Bidders realize that in a uniform price auction, if understating demand leads to a lower equilibrium price, that price will apply to all of the units purchased.

While Back and Zender (1993) assume that bidders have common values for the goods, Ausubel and Cramton's (1995) analysis extends to the case of independent private values and correlated values. They show that because bidders have incentives to manipulate their bids strategically in order to set a low price for inframarginal units, an efficient equilibrium does not exist. Inefficiencies arise because large bidders shade their bids and so may lose to smaller bidders with lower marginal valuations. Ausubel and Cramton only consider possible equilibria in which participants strategically bid above their valuations through several examples.

Von der Fehr and Harbord (1993) develop a specific model of the UK spot market as a first-price sealed-bid multi-unit auction. They consider the case of n generating companies of equal size with constant marginal costs. Marginal costs differ across company, though all costs are common knowledge. They demonstrate that no pure-strategy bidding equilibrium exists for a range of levels of electricity demand relative to the suppliers' generating capacities. Their result is driven by the conflicting incentives, discussed above, to bid high in order to set a high price and bid low to ensure that a plant is called. Though they comment that a model with asymmetrically-sized generators would probably involve the larger one bidding more, they do not consider that situation. Instead, they emphasize that generators with higher costs will submit higher bids, on average.

The Appendix provides an equilibrium model involving the types of strategic bidding discussed by both Back and Zender and Ausubel and Cramton. Following von der Fehr and Harbord, the details of the model are adapted to the institutional arrangements of the British electricity auctions. The model involves two generators which each own one unit with marginal cost c. Demand varies randomly so that sometimes only one of the two companies' units is needed and sometimes both companies' units are needed. They each submit bids for the right to supply power from those units. One of the generators also owns m units with zero marginal cost that are assumed always to be inframarginal. Taking off from von der Fehr and Harbord's demonstration that no pure-strategy bidding equilibria exist, I show the optimal bid distribution for the supplier with the inframarginal capacity first order stochastically dominates the smaller supplier's bid distribution.

The intuition behind the strategic bidding presented in the Appendix is straightforward. When there is a positive probability that a participant's bid for a given unit will be marginal and hence set the equilibrium price, the bidder has an incentive to increase that bid in order to set a high price for all the inframarginal units he supplies.[14] The incentive to manipulate one's bid strategically is increasing in the number of inframarginal units for which the marginal bid is likely to set the price. At the same time, the bidder's incentive to increase his bid is tempered by the fact that submitting a high bid will reduce the likelihood that it becomes marginal. One of the examples presented by Ausubel and Cramton (1996) (Example 8.3) is similar in nature to the model in the Appendix, but assumes bidders do not have perfect information about other bidders' valuations. For some

[14] I am assuming the participants are bidding to supply a good. Obviously, if a participant is bidding to buy a good, he has an incentive to submit a low bid for units likely to be marginal to reduce the equilibrium price.

distributions of bidder types, Ausubel and Cramton derive a unique, pure-strategy equilibrium.[15] Though both the Appendix to this paper and Ausubel and Cramton's example only involve competition for one unit, a more sophisticated model involving random demand over a larger support and asymmetric bidders would be considerably more involved (and might not have an analytical solution at all). The empirical results in this paper consider the applicability of the intuition and results of the simpler models.

Another prevailing model of the electricity pool is the one proposed by Richard Green and David Newbery who, in a series of papers, show how the generators' bid schedules correspond to the supply function equilibrium (SFE) concept developed by Klemperer and Meyer (1989) (see, *e.g.*, Green and Newbery, 1992; Green, 1996 and Newbery, 1992). It is worth considering how the SFE framework and some of the results presented by both Klemperer and Meyer and Green and Newbery correspond to some of the predictions of the multi-unit auction literature.[16]

Klemperer and Meyer demonstrate that it is not optimal for producers to commit to a given price or quantity, as the Bertrand and Cournot models respectively predict, when demand is stochastic. Instead, they characterize the optimal strategies for Nash competitors in a stochastic setting as entire price-quantity schedules, or supply functions. They show that possible supply function equilibria (a unique equilibrium only exists given certain conditions, see Klemperer and Meyer's Proposition 4) are solutions to a system of differential equations defined by profit-maximizing firms' first-order conditions.

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[15] Though Ausubel and Cramton's example does not involve random demand, it is straightforward to incorporate varying demand levels and to show that a unique pure-strategy equilibrium will still exist.

[16] Von der Fehr and Harbord (1993) question the applicability of the SFE concept to the electricity auctions. They argue that the size of individual generating units are large so that approximating the stepped bid functions with a smooth supply function is inappropriate.

Demand in the electricity spot market is not characterized by a high degree of uncertainty. Each generator, however, submits one schedule of prices and quantities for an entire day which is in turn used to produce prices for forty-eight separate periods. For that reason, Green and Newbery contend that an extension of Klemperer and Meyer's framework applies to the electricity spot market, as the variation in demand over the course of a day is analogous to potential variation across states of the world. The daily bid functions submitted by the generating companies, therefore, are explicit supply functions. Several of the comparative static results derived by Klemperer and Meyer are relevant to the empirical analysis of the bids that follows. For instance, the framework presented in this paper follows the auction literature in assuming that the amount bid for is not a function of the equilibrium price. (Demand varies exogenously between $m+1$ and $m+2$ units in the Appendix.) In the electricity spot market, however, there is potentially some interdependence between the amount of electricity demanded in a given period and the equilibrium price. In other words, electricity demand is not perfectly inelastic. The bid functions will vary based on differences in demand elasticities to the extent the generating companies perceive such differences and account for them in setting their bids. Klemperer and Meyer show that if demand becomes more inelastic over a certain range, then the unique SFE will be steeper and lie above the original SFE in that range (see Propositions 6 & 7). In other words, suppliers will raise prices at all quantities in that range.[17]

Klemperer and Meyer focus on SFE for a symmetric duopoly. Given that National Power is approximately fifty percent bigger than PowerGen, the applicability of that assumption to the pool is limited. Though it is much more difficult to describe potential SFE for asymmetric suppliers, both Newbery and Green (1991) and Newbery (1992) present results based on two asymmetric firms (modeled after National Power and PowerGen). Newbery and Green solve for asymmetric SFE by numerically integrating the requisite differential equations and Newbery solves for equilibria

[17] Note that because the SFE framework embodies an elastic demand curve, an SFE is not necessarily increasing in a supplier's marginal costs. Compare that to Prediction 1 in Section 4.

analytically by assuming constant marginal costs and linear demand. Both expositions demonstrate that the larger supplier submits prices reflecting markups above its marginal cost that are larger than the markups of the smaller supplier.[18] That result is consistent with the prediction of the multi-unit auction literature (see *e.g.* Ausubel and Cramton, 1996). Newbery (1992) also highlights the role of capacity constraints. In the equilibria he presents, the larger of the two suppliers charges the monopoly price (based on the residual demand) for all realizations of demand at and above the point where his competitor reaches a capacity constraint. In the British electricity industry, however, there are some days on which there is a very low probability that the daily maximum demand, net of supply from Nuclear Electric, France and Scotland, will be greater than PowerGen's total capacity.

4. EMPIRICAL RESULTS

In this section, I present results from an analysis of the daily bids submitted by the electric generating companies in England and Wales. The analysis focuses on the two largest companies, National Power and PowerGen, for several reasons. First, the bids of the next largest generating company, Nuclear Electric, are dictated by the operating requirements of nuclear power plants (which are primarily driven by safety regulations). Because nuclear power plants cannot easily be turned on and off, Nuclear Electric frequently submits a bid of zero for capacity from a plant that is already running. Second, the other suppliers to the pool are much smaller than National Power and PowerGen and the marginal operating costs of their plants are low. Those factors imply both that the other suppliers have little inframarginal plant to consider when bidding, and that if they bid close to their marginal costs, their plants will rarely be marginal.

The theoretical framework developed in Section 3 suggests several explicit predictions about National Power and PowerGen's bidding behavior in the electricity pool. First, the marginal costs

[18] Also see the discussion of asymmetric suppliers in Green and Newbery (1992).

among plants that burn different fuels are clearly rankable. Combined-cycle gas turbine plants and oil plants have the lowest marginal operating costs. Coal plants are more expensive and peaking gas turbines have the highest marginal costs. Since there is more inframarginal capacity when the more expensive plants are run, we would expect the bid markup over marginal cost to be higher for the more expensive plants:

Prediction 1: Markups will be higher for units that have higher marginal fuel costs. [19]

Second, National Power has nearly 50 percent more capacity than PowerGen, though the two companies proportionate mixes of plants of the various fuel types is very similar. Therefore, since it has more inframarginal capacity:

Prediction 2: National Power's bids for units with similar operating characteristics will be higher than PowerGen's.

Third, units are periodically taken in and out of service for a number of different reasons. Therefore:

Prediction 3: Bids for a given unit will be higher on days when more of the units that run before it and are owned by the same generating company are in service.

I test those three predictions by estimating versions of the following equation using both ordinary least squares and instrumental variables[20]:

$$\begin{aligned} ln(MARKUP_{ijt}) = {} & \beta_1 * PLANT\ FUEL_{ij} + \beta_2 * NATIONAL\ POWER_{ij} * PLANT\ FUEL_{ij} \\ & + \beta_3 * ln(AVAILABLE\ MEGAWATTS\ BELOW_{ijt}) \\ & + \beta_4 * ln(DAILY\ AVG.\ DEMAND_t) + \beta_5 * TIME\ DUMMIES_t + \mu_i + \varepsilon_{ijt} \end{aligned} \tag{2}$$

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[19] Note that the incentive to bid strategically holds even if all units have the same marginal cost. Prediction 1 uses marginal costs as a proxy for the segment of the supply schedule a unit is on and, hence, the amount of capacity inframarginal to the unit.

[20] Laffont, Ossard and Vuong (1995) and Laffont and Vuong (1991) propose a structural approach that allows one to infer the joint distribution of bidders' valuations from observations on equilibrium bids. The merits of that approach are not relevant here as it is straightforward to obtain a reliable measure of the bidders' valuations based on their bids and information about their costs.

for generating unit i, owned by generator j on date t. β_1 is the vector of coefficients on the plant fuel-type dummies and its components are predicted to be increasing in the marginal cost associated with the fuel (see Prediction 1 above). β_2 is the vector of coefficients on the fuel dummies interacted with a dummy variable equal to one if the bids are for National Power's plants and, according to Prediction 2, should be positive. β_3 is the coefficient on a measure of the amount of capacity likely to be used before plant i that is available on a given day and should be positive per Prediction 3. Variables measuring the average daily demand and dummy variables for different days of the week and months are included as controls in some specifications. μ_i is a generating-unit fixed effect estimated in some specifications and not others, and ε_{ijt} is a random disturbance term assumed orthogonal to the rest of the model.

Data

The data used to estimate equation (2) consist of observations from each day in six months (January, February, March, April, July and November) from each of the three calendar years between 1992 and 1994. All of the information on the generators' bids as well as on average daily quantities was obtained from the National Grid Company. Simple summary statistics on the data are presented in Table 1.

The variables presented in Table 1 reflect several calculations. First, as discussed in Section 2, a generating unit's bid consists of several prices, including the startup price, the noload price and separate slopes for up to three output increments. Those prices were combined to form *BID* following the formula the pool administrator uses (equation (1)), except that, since I do not observe the actual output, I select one of the three intervals based on the unit's assigned availability[21] rather

[21] Every day, the pool calculates a generating set's assigned (or "actual") availability for the following day by discounting the capacity the generator declares if the plant has recently been unavailable.

than its output.[22] *BID* does not reflect the submitted startup price, though separate calculations show that even if all the generators only ran fifty percent of the time on a given day, this would account for less than five percent of the total submitted price.[23]

The numbers in the first row of Table 1 imply that *BID* has quite a large coefficient of variation – nearly two. Since that figure reflects the standard deviation of *BID* both across generating units and for a particular unit over time, it is possible that the large variation simply reflects the fact that bids for different types of units are different and reveals nothing about the extent to which a given unit's bid varies over time. The next two rows of Table 1 report the standard deviation between generating units and within a particular unit, respectively. Those numbers confirm that there is considerable variance in units' average bids, but that the variance in a given unit's bid over time is even larger. It is useful, therefore, that Prediction 1 allows me to test for strategic bidding by considering units' average bids while tests of Prediction 3 use variation in bids over time.

The calculations and information used to generate *MARGINAL COST* are described in detail in Wolfram (1996). Given the short time period for which prices are set, only fuel costs are considered marginal. *MARGINAL COST*, therefore, reflects the cost of the fuel burned by a plant to generate electricity. For the coal, gas and oil plants, the fuel cost is based on the price of the fuel and the efficiency with which the plant converts the fuel to electricity. The variable is calculated at a plant level and varies over time only as often as the fuel prices vary, which is at most once a month.

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[22] Nearly seventy percent of the time, the suppliers submit only one increment so that the mechanism for choosing between the weighted increments is irrelevant.

[23] The startup prices are higher for National Power's plants, so accounting for them would, if anything, strengthen the results presented below regarding Prediction 2. Startup prices are higher for coal than for gas or oil plants, but the differences would not offset the results regarding Prediction 1.

The *MARGINAL COST* assigned to the combined-cycle gas-turbine plant is assumed to be constant and equal to £16 per megawatt-hour.[24] *MARKUP* is the ratio of *BID* to *MARGINAL COST*.

The next three variables capture the amount of capacity that is likely to be run before a given generating unit on a given day. All three variables are calculated separately for National Power and PowerGen so that, for instance, only other National Power units are considered inframarginal to a National Power unit. *AVAILABLE MEGAWATTS BELOW 1* reflects the sum of the capacity available on a given day from units with lower marginal costs. Units with lower marginal costs, therefore, are assumed to be inframarginal to a given unit. As I discuss below, units' marginal costs are poor indicators of their dispatch position. I developed *AVAILABLE MEGAWATTS BELOW 2* as another measure of inframarginal capacity. To construct it, I first calculated each unit's average bid on weekdays and, separately, on weekends in a given month. I ranked the units based on their average bids and then calculated, for each unit, the capacity available on a given day from units with lower average bids. *ACTUAL AVAILABLE MEGAWATTS BELOW* ranks the units by their bids to determine the capacity that is actually inframarginal to a given unit.[25]

The within-unit standard deviations for the *AVAILABLE MEGAWATTS BELOW* variables indicate that there is considerable intertemporal variation in availability at the individual plant level. Though some of that variance is due to changes in the unit's relative ranking, much is due to changes in the availability of inframarginal units. As discussed in Section 2, suppliers are free to decide whether or not a unit may be called to supply electricity on a given day. Plants are routinely taken

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[24] CCGT costs are based on an assumed forty-five percent efficiency and fuel costs of 21 pence per therm (see Wolfram, 1996). Since all of the CCGT plants were built after privatization, plant-specific efficiency numbers are not available. Gas for the CCGT plants is usually procured under long-term, take-or-pay contracts, so assuming a fixed gas price is reasonable.

[25] Because my data do not include all of the operating constraints that the system administrator uses to develop the optimal dispatch schedule, the ranking is not quite "actual." It is much closer to the actual ranking than the other two measures.

out of service for maintenance. Occasionally, mechanical failures, accidents, fires, and other mishaps prevent units from generating. In addition, the suppliers may make strategic decisions to withhold capacity in order to increase the SMP and the capacity-related payments (see Wolak and Patrick, 1996).

Aside from unavoidable mishaps at plants, the suppliers choose the availability of their plants simultaneously with the bid prices. Specifications of equation (2) could pick up a spurious relationship between bid prices and availability as a measure of inframarginal capacity. For instance, if the suppliers were striving to minimize volatility in SMP, they might reduce bid prices and availability simultaneously. I report tests of the robustness of my results to one potential source of spurious correlation. In general, it appears as though β_3 can be consistently estimated and interpreted as a measure of the average slope of the generating companies' bid functions.[26]

The last variable in Table 1, *DAILY AVG. PREDICTED DEMAND*, reflects the average of the demand forecasts the pool administrator develops for each of the forty-eight half-hour periods on the following day and is included as a control in specifications of equation (2).[27] The generating companies are provided with the per-period predictions, and so it is reasonable to assume that they factor them into their bidding decisions. The predictions are made before the prices are determined and so do not (and, by pool rules, cannot) account for possible demand reactions to prices. For this reason, it is reasonable to treat the variable as exogenous to the bid level chosen by the generator.

[26] The model in the Appendix suggests that the incentive to increase a bid strategically is also a function of the probability that a generating unit will be declared marginal ($1-\pi$). Equation (2) does not account for the interaction between the number of units that a supplier makes available, average daily demand and that probability. It assumes that the probability of becoming marginal is fixed for a given generating unit. Given that intraday fluctuations in demand are much greater than interday and the generating companies submit only one bid per plant per day, that assumption seems reasonable.

[27] Recall that the supplier submits only one bid per day for each generating unit.

In addition to the variables listed in Table 1, equation (2) was estimated with a number of dummy variables included both to test some of the theoretical predictions and as controls. In order to test Predictions 1 and 2, dummy variables indicating a plant's fuel type were included both alone and interacted with a dummy variable equal to one if National Power owns the plant. In order to pick up temporal patterns in the bids, dummy variables for each month covered by the data set (*i.e.* there are separate dummies for July 1992 and July 1993) and for each day of the week were included as controls in some of the specifications.

Results

Table 2 summarizes information on bids and availability by fuel type and owner, providing both a description of the capacity ownership patterns in the industry and some suggestive evidence on Predictions 1 and 2. The numbers in the columns labeled "Megawatts" depict the average number of megawatts that each supplier declares as available from its plants. Comparing National Power and PowerGen's plants, we see that the mix of plants made available by the two companies is very similar. On average, eighty percent of their capacity is in coal plants.[28] If anything, National Power tends to have a slightly higher fraction of available capacity in gas plants and PowerGen has proportionately more coal and CCGT capacity.

Both National Power and PowerGen have several plants that are located such that they are frequently required to run in order to alleviate congestion on the transmission grid (see OFFER, 1992). Pool rules dictate that plants "constrained-on" because of transmission congestion be paid their bid, no matter what the equilibrium price.[29] As a result, the generators have an extra incentive to submit high bids for such plants. Ideally I would like to identify all of the plants which

[28] As described below, all of PowerGen's and most of National Power's "*Constrained-on*" capacity is in coal plants.

[29] In April 1994, the National Grid Company was given incentives to minimize Uplift, the component of the pool price through which constrained-on payments to generators (among other things) are collected. The NGC did not, however, change the payments made to generators.

the generators knew would be constrained to run on any given day. Since plants that bid knowing they would be paid their bid price were unlikely to set the SMP, I would exclude those plant-day observations from my data. Unfortunately, information on daily constraints is not available. OFFER (1992), however, lists plants that received significant payments related to operational constraints during 1991 and 1992. I characterized a plant as "*Constrained-on*" if it received payments in excess of \$65 million per average available gigawatt, and if the description of the transmission constraint in OFFER (1992) suggested that the plant was likely to continue to be constrained on during the time period covered by my data set. Five of PowerGen's coal plants (three of which were all or partially closed during the time period I study), three of National Power's coal plants and one oil plant met the criterion.[30] The bids in Table 2 seem to imply that PowerGen bid more for its constrained-on plants, but given the rough measure I use, it is likely that other plants were also constrained on at some time and that the plants I identify as "*Constrained-on*" were not always required to run. It is possible, therefore, that National Power's plants were constrained to run on fewer days.

Most of the capacity of suppliers other than National Power and PowerGen is bid in at very low prices and therefore rarely sets the marginal pool price. The minimum pool price observed during the entire time period covered by this data set was £8 per megawatt-hour, still above the average bid price submitted by either Nuclear Electric, France, Scotland or the independent CCGT owners. Pumped storage bids are comparable to those from National Power and PowerGen's plants and, accordingly, occasionally set the pool price.

The rows in Table 2 are arranged in order of the average *BID* for each fuel type. In support of Prediction 2, the ordering approximately correspond to the average marginal costs by fuel type.

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[30] The delineation of "*Constrained-on*" plants is admittedly somewhat *ad hoc*. If I do not distinguish "*Constrained on*" plants, the results are similar to those presented below, though the standard errors are larger.

Marginal costs for CCGTs are approximately £16 per megawatt hour; calculated marginal costs for coal plants average slightly more than £16 per megawatt hour and for oil and gas plants average approximately £11 and £45 per megawatt-hour, respectively. Aside from the oil plant *BIDs*, therefore, the submitted prices are increasing in the marginal cost of the unit. Comparing National Power's *BIDs* by fuel type to PowerGen's, it appears as though National Power submits higher *BIDs* for its CCGT and coal plants and less for its oil and gas plants. Of course, the numbers in Table 2 do not reflect the marginal costs of the companies' plants.

The results presented in Table 3 address the relationship between bid markups and both fuel type and plant ownership in more detail. The first two columns report coefficients and standard errors from a specification of equation (2) that did not include *DAILY AVG. PREDICTED DEMAND*, month or day-of-week dummies as controls, while the results in the third and fourth columns include the controls.[31] The variables of interest in both columns are the fuel dummy variables. Consistent with Prediction 1 and with the conclusions suggested by the summary statistics in Table 2, *MARKUPS* are lower for CCGT than for coal units and lower for coal than for gas units. The differences are quite dramatic. The *MARKUP* on a CCGT generating unit is on average forty percent of the *MARKUP* on a coal unit and the *MARKUP* on gas units are three times those on coal units. Given the extent of the differences, therefore, the ordering is clearly robust to a range of reasonable assumptions on the fuel costs or plant efficiency rates used to calculate *MARGINAL COSTS*.

The anomalous fuel-type result in Table 3 is that the average *MARKUP* for the oil plants is higher than both the coal and CCGT plants, even though its marginal costs are lower. The oil plants may have higher costs than are reflected in the calculated marginal fuel costs. For instance, I used the price of spot oil to calculate *MARGINAL COST* for the oil plants while the coal plants' costs are

[31] The standard errors in the second and fourth columns of Tables 3, 4, 5, and 7 adjust for the presence of heteroskedasticity following White's method and allow for serial correlation by generating unit.

based on long-term contracts between the generating companies and British Coal (see Wolfram (1996) for more detail). As a result, the coal prices may better capture the costs associated with the fuels' delivery, handling and quality-assurance and also capture any premium associated with the hedge against spot price fluctuations provided by the long-term contracts. Also, the British political environment essentially requires that the generating companies buy a certain amount of British Coal (and in fact the coal contracts in effect during the time period I analyze specified high minimum annual takes). The take-or-pay aspect of their coal purchases may lower the generators' perceived marginal costs for coal.

Prediction 2 suggests that since National Power owns approximately 50 percent more capacity than PowerGen, it has more of an incentive to try to increase the equilibrium price. The positive coefficients on the "National Power*CCGT", "National Power*Oil" and "National Power*Gas" dummy variables confirm that National Power is bidding *MARKUPS* that are 30 to 60 percent higher than PowerGen's on its CCGT, oil and gas plants. [32]

The coefficient on "National Power*Coal" is small and statistically indistinguishable from zero, implying that National Power and PowerGen are submitting similar bids for their coal plants. There are several possible explanations for that result. First, during fiscal years 1992 and 1993 (both the RECs' and the generators' fiscal years end March 31), the sum of the energy covered by National Power's contracts for difference (CfDs) and the energy it sold directly to large customers was greater than its total output (by 1.6 percent and 8.25 percent in fiscal years 1992 and 1993, respectively, see MMC, 1996). Since National Power was a net buyer from the pool during those years, it had an incentive to keep pool prices low. PowerGen, by contrast, was always a net seller, though just barely so in fiscal year 1993. When versions of the specifications in Table 3 are estimated separately for

[32] Several factors explain why the summary statistics in Table 2 suggest that National Power bids less than PowerGen for its oil and gas plants. For one, National Power's oil and gas plants have lower marginal costs. Second, estimating equation (2) in logarithmic form dampens the effects of some very high bids for PowerGen's oil and gas plants.

each fiscal year, the coefficient on the "National Power*Coal" variable is negative during fiscal years 1992 and 1993 (significantly so in 1992) and positive during fiscal years 1994 and 1995. The coefficient on the variable for a specification including data from fiscal years 1994 and 1995 combined is 0.15 (0.08).

The coefficient on "National Power*Coal" also seems to be affected by the fact that National Power has less capacity in CCGT units (see Table 2). For its first several coal units, therefore, PowerGen has more inframarginal capacity and so has an incentive to submit higher *MARKUPS* than National Power. When the bottom 10 percent of the bids are excluded and a version of the first specification in Table 3 is re-estimated with data from January 1993 through November 1994, the coefficient on "National Power*Coal" is 0.12 (0.07).[33]

Though National Power closed more plants over the time period covered by my data set, most of the closed plants were small, old and inefficient coal or gas plants. As a result, the closings did not affect the inframarginal capacity of most of National Power's coal plants. (Perhaps due to the closings, coefficients on the "National Power*Oil" and National Power*Gas" were smaller in fiscal year 1995 than in 1992.[34]) Though it is clear that other factors affect bidding in the pool, such as contract coverage, the results presented in Table 3 and the supplemental calculations presented above provide evidence consistent with Prediction 2.

The specifications reported in the final two columns of Table 3 also included *ln(DAILY AVG. PREDICTED DEMAND)*[35] as well as dummy variables for each month and day of the week. The

[33] I confine this specification to January 1993 through November 1994 not only because of the contract coverage issue discussed above, but also because National Power and PowerGen's CCGT plants were not fully operational until December 1992. Using all the bids over the same time period yields a lower coefficient.

[34] It is somewhat puzzling that National Power is submitting high *MARKUPS* for its CCGT plants. PowerGen, however, is vertically integrated backwards into gas production, and so may face lower gas costs.

[35] In other specifications, I included lagged demand variables and a variable indicating the percent

coefficients on the fuel dummy variables are virtually unchanged with the introduction of the controls, though the coefficients on the controls are for the most part highly significant. The results suggest that the companies bid less when demand is high, though the coefficients on the day-of-week dummies suggest that the generators bid low *MARKUPS* during the weekend and higher on weekdays.[36] (The average daily demand on a weekend is 28 gigawatts per hour and on a weekday is closer to 35 gigawatts per hour.) Though the coefficient on *ln(DAILY AVG. PREDICTED DEMAND)* is highly significant,[37] typical changes in that variable are very small (see Table 1) implying that changes in daily demand have a small impact on bidding behavior. One plausible interpretation for the coefficients on the controls is that the generators perceive demand to be less elastic when demand is low on weekdays and, consistent with Klemperer and Meyer's SFE framework, increase the slope of their bid functions.[38] Supporting that explanation, Wolfram (1996) finds both that demand is more elastic in the winter when demand is high than in the summer when demand is low and that pool prices respond, though very slightly, to changes in demand elasticity. Further, the magnitude of the sensitivity of equilibrium pool prices to demand elasticity found in Wolfram (1996) is roughly consistent with the coefficients on the demand variables in Table 3.

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of periods in a day classified as Table B. While some of these controls were significant in some specifications, they did not greatly enhance the fit of the model and the estimates of the coefficients of interest were very similar to those presented in Tables 3 through 8.

[36] The unreported coefficients on the month dummies do not display distinct patterns across months. There is considerable variations, for instance, between November 1994 and November 1993. The month coefficients do indicate an upward trend in *MARKUPS* over the time period considered.

[37] The coefficient on *ln(DAILY AVG. PREDICTED DEMAND)* is also robust to the inclusion of generating-unit fixed-effects (see Tables 4 and 5).

[38] It is possible that demand is less elastic on weekends even though the level demanded is low, but on a given day of the week, demand is more elastic when more is demanded. That would be true if, for instance, industrial customers are more sensitive to changes in price when prices are high (*i.e.*, when demand is high) and if there is less industrial consumption on weekends.

Tables 4 and 5 present results from estimates of equation (2) that seek to test Prediction 3 by including measures of the *AVAILABLE MEGAWATTS BELOW* a given generating unit. Prediction 3 states that bids for a given generating unit will be higher on days when more of the capacity that is likely to be run before that unit (*i.e.*, capacity that is inframarginal to the unit) is available. The results based on Prediction 3 provide the most direct test of the extent to which the generators are adjusting their bids to account for their inframarginal capacity. Results based on Predictions 1 and 2 provide comparatively blunt tests. They do not take full advantage of the daily data available on the electricity auctions because there are only four different fuel types and two (major) generators, facts which do not change over the time period covered by the data set. On the other hand, available capacity varies on a day-to-day basis for each generating unit. Unfortunately, obtaining a good measure of the capacity that is inframarginal to each plant is not straightforward, complicating attempts to estimate β_j in equation (2).

The specifications reported in Table 4 include the variable *ln(AVAILABLE MEGAWATTS BELOW 1)*. As described above, that variable was constructed by ranking the generating units based on their *MARGINAL COSTS* and then, for each generating unit, summing the capacity available on a given day that has lower marginal costs and is owned by the same generator.[39] The results in the first columns do not include generating-unit fixed effects. Consistent with Prediction 3, the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 1)* is positive and significant.[40] If I allow the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 1)* to vary by producer, the coefficients are statistically

[39] Every day, there is one generating unit per company with zero megawatts of capacity below it—the first unit. To accommodate the log transformation of all of the *AVAILABLE MEGAWATTS BELOW* variables, I exclude that unit. The results are unchanged if I instead include observations for the lowest plant by taking *ln(AVAILABLE MEGAWATTS BELOW + 1)*.

[40] Since the fuel price changes reflected in *MARGINAL COST* are at most month-to-month and the results in Table 4 include month fixed effects, the fact that rankings based on *MARGINAL COST* are used to generate ln*(AVAILABLE MEGAWATTS BELOW 1)* does not induce a relationship between the measure of inframarginal capacity and the dependent variable.

indistinguishable. This suggests that the two generators submit similar markups when their units have the same inframarginal capacity.[41]

The positive coefficient on *ln(AVAILABLE MEGAWATTS BELOW 1)* in column 1 of Table 4 may simply reinforce the results presented in Table 3 (*e.g.* that gas plants bid the highest *MARKUPS* and have the most inframarginal capacity). Worse, it could simply reflect the fact that more expensive plants are represented in the data when availability is higher. In order to control for such an effect, the third and fourth columns of Table 4 report results that include generating-unit fixed effects. In those specifications, contrary to Prediction 3, the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 1)* is negative and almost statistically significant at conventional levels. It is probable, however, that ranking the plants based on their marginal costs does not accurately capture the order in which the plants are operated. For the coal plants, for instance, plant rankings are sensitive to very small differences in observed costs.[42] If additional factors dictate the order in which the plants are run, the estimate of the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 1)* will be biased.

To evaluate the extent to which the coefficients on *ln(AVAILABLE MEGAWATTS BELOW 1)* reported in Table 4 are biased by measurement error due to misranking, Table 5 reports results based on *ln(AVAILABLE MEGAWATTS BELOW 2)*. As described above, the second availability variable was constructed by taking the average of a generating unit's bids on weekdays or weekends in a given month and then ranking the units by that average bid. On the one hand, using the bid submitted for a

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[41] When I include owner and fuel-type dummy variables in a specification similar to the first column of Table 4, the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 1)* reflects changes in *MARKUPS* as a function of inframarginal capacity for plants with a given fuel type and owner. The coefficient is somewhat smaller ($\beta = 0.12$, standard error = 0.05), and separate coefficients by generator are still indistinguishable.

[42] For coal generating units, the correlation between the rank of a unit by its bid and the rank of a unit by its marginal cost is only 0.69.

generating unit necessarily improves the accuracy of the ranking, since the bids are what the pool uses to rank units. On the other hand, a unit's ranking by its bid is essentially a monotonic function of the dependent variable.[43] The results reported in Table 5, however, include fixed effects for each generating unit on a weekday or weekend in a given month (*i.e.*, they include nearly 207*18*2 fixed effects, for each generating unit, month, and weekday or weekend, respectively, in the data set), so the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 2)* is identified off of changes in the availability of units likely to be inframarginal to a given unit and *not* changes in the ranking of the unit because of changes in its bid.

The results reported in the first two columns of Table 5 are comparable to those in the last two columns of Table 4. While the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 1)* in Table 4 was negative, the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 2)* is essentially zero. (The statistical insignificance is due to the small estimated coefficient; the standard errors on *ln(AVAILABLE MEGAWATTS BELOW 2)* are smaller than those on *ln(AVAILABLE MEGAWATTS BELOW 1)* in Table 4, even though the specifications includes many more fixed effects.) The difference between the two coefficients suggests that *ln(AVAILABLE MEGAWATTS BELOW 1)* may have reflected an inaccurate ranking of the generating units and thereby biased the coefficients reported in Table 4.

The last two columns of Table 5 present results in which *ln(AVAILABLE MEGAWATTS BELOW 2)* is used as an instrumental variable for *ln(ACTUAL AVAILABLE MEGAWATTS BELOW)*.[44] Using an instrumental variables approach allows me to use the most accurate measure of

[43] Because the dependent variable is the ratio of a unit's bid and marginal cost, it will not necessarily increase when the bid rises. In fact, changes in *MARGINAL COST* are much smaller than changes in bid, so the monotonic relationship is strict.

[44] There are fewer observations in the IV specification because the two ranking methods cause different units to be the first unit – the unit that is dropped because if has zero megawatts of available capacity.

inframarginal availability as an independent variable without introducing bias by imposing a relationship between the rankings and the dependent variable.[45] The second availability measure is a very good instrument for the actual availability: the coefficient on *ln(AVAILABLE MEGAWATTS BELOW 2)* in the first stage is 0.81 (0.07). While the coefficient on the availability measure is slightly larger than in the OLS specification (0.020 compared to 0.009), the standard error is larger as well. From these results, it is difficult to conclude that the generators are increasing the bids for a given generating unit when more of the capacity inframarginal to that unit is available.

In additional specifications, I allowed the coefficient on the availability variables to differ across generator. Generally, these results suggest that National Power is raising units' bids when they have more inframarginal capacity but that PowerGen is not. In specifications similar to those in the last two columns of Table 5, the coefficient on *NATIONAL POWER*ln(ACTUAL AVAILABLE MEGAWATTS BELOW)* is 0.07 (0.03) while the coefficient on *POWERGEN*ln(ACTUAL AVAILABLE MEGAWATTS BELOW)* is -0.03 (0.03). (An F-Test of the hypothesis that the coefficients are equal is rejected at the two percent significance level - $F(1,59415) = 6.19$.) The difference between generators persists across fiscal years. It is possible, however, that PowerGen is subject to more of the measurement issues discussed below.

Alternative Explanations

The results presented above provide some evidence of strategic bidding by National Power and PowerGen. Clearly, however, other factors influence bidding in the pool - the reimbursement rule for constrained-on plants and contracts for difference have already been identified above. In the following paragraphs, I evaluate the sensitivity of the results presented thus far both to additional factors influencing the market and to measurement issues.

[45] An OLS specification that simply included the endogenous variable *ln(ACTUAL AVAILABE MEGAWATTS BELOW)* on the right-hand side yielded the following coefficient: 0.277 (0.009). The difference between the IV and OLS results suggests that the relationship between a unit's ranking and its markup leads to biases in the OLS results.

i. Mismeasured marginal cost

Since the dependent variable is the ratio of observed bids to calculated marginal costs, one source of potential bias is the marginal cost calculations. For instance, the results pertaining to Prediction 1 (see Table 3) would be biased if the marginal cost estimates systematically understate the costs of gas plants and overstate costs of coal and CCGT plants. Because they suggest such large differences in markups across plants with different fuel types, the results regarding Prediction 1 are clearly robust to a range of assumptions about costs. In the extreme, even if the generators are bidding relative to the generating units' *average* costs, additional calculations suggest that the markups still follow the ranking implied by the results in Table 3.[46] Results pertaining to Prediction 2 would be biased if the marginal cost estimates I use systematically underestimate National Power's costs relative to PowerGen's. For instance, PowerGen's coal plants tend to be bigger than National Power's, so if the plant efficiency measures I use underestimate economies of scale, I am likely to be underestimating PowerGen's markups for coal plants. The efficiency numbers, however, are based on engineering data made publicly available during the time that the industry was state-owned and so are unlikely to be biased.

The results presented in the last two columns of Table 4 and in Table 5 are for the most part immune to any bias due to mismeasured marginal costs since they include fixed effects by generating unit-month-weekend. Even if marginal costs vary over several months in ways that are not reflected in my calculations of *MARGINAL COST*, for instance as the ambient temperature changes, my results would be unaffected. Marginal costs may also vary day-to-day based, for instance, on whether or not the plant was running the previous day. Neglecting those costs could impart a positive bias to the coefficients reported in Table 5 if ramp-up costs and availability are correlated (*e.g.* if they are both

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[46] To perform these calculations, I used the capacity costs and projected plant lives listed in MMC (1996) and assumed gas plants were run during 1-2 percent of the half-hour periods in a year, coal plants were run during 70 percent of the periods and CCGTs during 85 percent.

higher during the week and lower on weekends). Any systematic day of the week effect is mitigated because I include the day of the week dummies. Also, the coefficient on the availability variables are very similar when generating units unavailable on the previous day are omitted. There may be additional factors affecting day-to-day cost differences, though none that are likely to be systematically related to availability.

ii. Independence of observations day-to-day

Though all of the standard errors in Tables 3 through 5 account for both serial correlation and heteroskedasticity, I also explored the sensitivity of the coefficient estimates to serial correlation. The generators do not change their bids every day. Only 25 percent of the bids in my data set were changed from the previous day. Table 6 provides a tabulation of the fraction of generating units which change their bids on each day of the week. The results suggest that the generators change the bids for most plants once or twice a week. Nearly fifty percent of the units' bids are changed on a typical Monday while only twenty percent of the bids change on other weekdays. Twenty-five percent of the bids are adjusted on Saturdays and very few units' bids are changed on Sundays. The middle column of Table 6 reports the absolute value of the change in the bid price. The largest changes in prices occur on Mondays and Saturdays.

Because of the patterns described in Table 6, I estimated specifications of equation (2) similar to those in Table 5 but only used observations from Mondays and Saturdays.[47] The results demonstrate a stronger relationship between availability and markups than we saw in Table 5. In a specification similar to the last column of Table 5, the coefficient on *ln(ACTUAL AVAILABLE MEGAWATTS BELOW)* is 0.053 (0.034).[48] If the generators change their bids weekly and the

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[47] Another possibility would have been to estimate specifications similar to those in Table 5 only using observations if they represent a new bid. I chose not to do that because of the possibility that the decision to change a bid is correlated with some factor not accounted for in the regression.

[48] I obtained very similar results to those reported when I used averages (of both the dependent and independent variables) over weekdays and weekends instead of observations from Mondays

availability of inframarginal plants changes over the course of the week (in ways that are unforeseeable to the generators), using all of the observations introduces measurement error to the coefficient estimates. In fact, the difference between the actual inframarginal availability on Monday and the actual availability on subsequent weekdays increases monotonically from Tuesday through Friday. The difference increases from ten to nineteen percent of the value of *ACTUAL AVAILABLE MEGAWATTS BELOW*. Though it is unclear why the generators do not re-optimize their bids on subsequent days, the results based only on Mondays and Saturdays suggest that the generators increase their bids for a given plant when more of the inframarginal capacity is available.

iii. Bids unlikely to set marginal price

Aside from measurement issues, the fundamental problem I have identifying the sensitivity of my results to additional factors is that I do not observe and cannot measure all the incentives the bidders face. I have information on some factors (other than the desire to be included in the regular dispatch) which may be driving bidding (such as constrained-on operation). It is also likely that there are a number of other motivations the bidders face which I cannot account for—either because I do not know what the incentives are or because I cannot determine when they exist. Since the theory behind strategic bidding only pertains to bids for units that are likely to set the marginal price, I would ideally like to be able to identify all units on a given day that are not likely to set the marginal price and exclude them from my analysis.[49] The range of bids included in my data set lie far outside the range of marginal prices.[50] Over the eighteen months for which I have data, the highest marginal

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and Saturdays.

[49] For the time period I consider, the identity of the marginal unit was not released to the public.

[50] Presumably, if the generators knew exactly which plants would be marginal, and if there were no additional considerations, they would declare plants that would not be called as unavailable. The generators face some uncertainty as to which plant will be needed, but it is more likely that the out of range bids are submitted for additional reasons (including transmission constraints, payments for the provision of capacity or ancillary services, and costs involved in changing the bid from day to day).

price (SMP) was £116 per megawatt-hour, while three percent of the bids were more than five times that high. Specifications similar to those in Table 5 excluding any bid above £120 per megawatt-hour are presented in Table 7. While I am selecting on the left-hand side variable to generate these results, the theory that I am trying to test is only relevant for bids likely to set the marginal price. Results similar to those in Table 7 were obtained using alternative criteria to identify bids unlikely to set the marginal price. In addition to testing the sensitivity of the results presented to the level of the cutoff, I also excluded any unit that ever set a price above a certain threshold. The latter exclusion criteria is excessively strict because, for instance, a unit may bid to set the marginal price on a day it knows it will not be constrained on, and bid higher when a transmission constraint is operative.

The results in the first two pairs of columns in Table 7 mirror those in Table 5 and the results in the last two columns are based only on Mondays and Saturdays. All three sets of results suggest a statistically significant positive relationship between a given generating unit's bid and the available inframarginal capacity. The results in the last two columns imply a ten percent change in inframarginal capacity leads to a 0.6 percent change in the markup.

When the coefficient on the availability variable is allowed to vary by generator, the difference between National Power and PowerGen persists. With bids only from Monday and Saturday (analogous to the results in the last two columns of Table 7), the coefficient on *NATIONAL POWER*ln(ACTUAL AVAILABLE MEGAWATTS BELOW)* is 0.140 (0.039) and the coefficient on *POWERGEN*ln(ACTUAL AVAILABLE MEGAWATTS BELOW)* is -0.061 (0.049). The coefficients do not seem to be driven by erratic bidding during a certain time period. It is possible that I have not fully characterized the transmission constraints faced by PowerGen, though the results do not seem to be driven by a distinct group of PowerGen's plants. On any given Monday, however, National Power is three times as likely as PowerGen to change its bids, so the coefficient for PowerGen's plants may still be plagued by measurement error. It is also possible that PowerGen is not bidding strategically in the same way that National Power is, though it is unclear why this would be the case.

iv. Additional relationship between bids and availability

Since the availability decisions are made simultaneously with bid decisions, it is possible that there is no direct relationship between availability and bid markups but that decisions about the level of the bids and the amount of capacity are both correlated with other factors. To assess that possibility, I compared the coefficients on the availability variables on days when it is likely that strategic considerations played an important role in the generating companies' availability decisions to days when the level of availability is more likely to be determined by (exogenous) operational conditions. Wolak and Patrick (1996) suggest that, because the generating companies face a nonlinear benefit from manipulating their plant availability levels, the companies have a particularly strong incentive to withhold capacity in order to increase both the capacity-related payments and the System Marginal Price during certain periods. If the companies are also lowering their bid prices for some units on days when they are withholding capacity, and the positive coefficient on the availability variables in Tables 4 and 5 and 7 may reflect this behavior.

As Wolak and Patrick report, there are a small number of time periods when the capacity-related payments are a significant fraction of the pool price.[51] It is likely that the companies are withholding capacity in those periods. To test the hypothesis put forward above, I allowed the coefficient on *ln(ACTUAL AVAILABLE MEGAWATTS BELOW)* to vary between days when the capacity-related charges were on average more than ten percent of the total PPP (this happened on seven percent of the days covered by my data set) and all other days. In specifications analogous to those in the middle two columns of Table 7, the coefficient for days when there were larger capacity-related payments -- 0.043 (0.020) -- was only slightly (though statistically significantly) larger than

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[51] Wolak and Patrick also show that these are not necessarily the periods when demand is highest. Therefore, simply including *ln(DAILY AVG. DEMAND$_t$)* may not control for differences across days.

the coefficient for all other days – 0.041 (0.020).[52] That result provides more evidence that the positive coefficients on the availability variables are not spurious and do reflect strategic manipulations to account for inframarginal capacity.

The IV results presented in Tables 5 and 7 do not address the possible simultaneity between availability and bid decisions because the instrument reflects daily changes in availability. However, I created another variable by simply taking averages of *ln(AVAILABLE MEGAWATTS BELOW 2)* over weeks and weekends and used that as an instrument. In a specification similar to the middle columns of Table 7, the coefficient on *ln(ACTUAL AVAILABLE MEGAWATTS BELOW)* was 0.083 (0.025). To the extent that strategic availability decisions are not correlated over the course of a week, that result provides further confirmation that the positive coefficients on the *AVAILABLE MEGAWATTS BELOW* variables in Tables 4, 5 and 7 reflect strategic bidding.

v. Capacity constraints

Another possible explanation for the positive coefficients on the availability variables in Tables 4, 5 and 7 is that generating units which have a lot of inframarginal capacity also have more market power than other plants. In other words, there is little surplus capacity when those plants are marginal. (It is also reasonable to assume that the price elasticity of demand is not substantially higher). For instance, von der Fehr and Harbord (1993) show that when demand is higher than the total capacity of the largest generator (in a duopoly setting), the generators will bid the highest possible price (see their Proposition 3). To assess that possibility, I estimated the specifications reported in Tables 5 and 7 separately for plants of each fuel type. If the market-power explanation holds, we would expect the coefficient on the availability variables to be low or zero for the CCGT and coal generating units and high for the gas units. That was not the case. In specifications similar to those in the middle of Table 7, the coefficients on *ln(ACTUAL AVAILABLE MEGAWATTS*

[52] The magnitude of the difference between the two coefficients is not sensitive to the definition of a high capacity charge day.

BELOW) for coal plants was 0.044 (0.025) and the coefficients for oil and gas plants were, respectively, 0.008 (0.013) and -0.087 (0.042). Those results imply that, to the extent there is a positive relationship between availability and bid prices, the generating companies are strategically increasing their bids in order to set higher prices for their inframarginal capacity rather than to exploit market power.

5. CONCLUSIONS

This paper considers the bids submitted in the daily electricity auction in England and Wales. The high frequency of the auctions as well as the rich variation in the attributes of the bidding companies and the characteristics of their plants permit me to examine several manifestations of strategic bidding. The evidence clearly suggests that the companies increase their bids in order to raise the price they are paid for inframarginal capacity. First, I find that the generators bid larger markups for plants with high marginal costs, *i.e.* those that are likely to be used after a number of other plants are already operating. Second, National Power, the larger supplier, submits bids reflecting larger markups over its plants' marginal costs than does PowerGen, its smaller competitor. Lastly, there is some evidence that bids for a given unit are higher when more of the units likely to run before that unit are available to supply electricity.

Theoretically, the equilibrium allocation of goods through auctions where strategic bidding takes place will be inefficient (see Ausubel and Cramton, 1996). For instance, if National Power is continually submitting bids reflecting larger markups than are reflected in PowerGen's bids, PowerGen's plants will be run more frequently, even though they may be more expensive. Because there are only small differences in the operating costs of National Power and PowerGen's plants, however, any such inefficiencies are likely small. For instance, even if all of PowerGen's gas plants are run before any of National Power's gas plants, the cost of using *half* of the gas plants would only increase by approximately five percent. (Note that the cost of using *all* of the gas plants would be unchanged.) Efficiency losses due to strategic bidding could potentially be more severe in other settings, for instance, if there are large differences between the costs of plants owned by companies of different sizes.

Incentives for strategic bidding of the type documented in this paper would not exist if the electricity auction were discriminatory, that is, if the generators were paid for output from each plant based on the plant's bid. In 1994, the electricity regulator considered arguments in favor of adopting a discriminatory pricing policy (OFFER, 1994). He decided not to change the auction format, and it is worth reviewing his rationale. The regulator noted that if the generators were paid their bid prices they would most likely stop submitting steeply increasing bid functions and might instead try to estimate the average marginal price over a day and bid that price for all of their plants. That type of behavior would lead to three sources of inefficiencies. First, flat bid functions would leave the system dispatcher with little information on which plants to run first in order to minimize the cost of meeting different levels of demand. That sort of allocative inefficiency could lead to large distortions. For instance, the average level of demand requires that approximately 70 percent of the coal plants be run. Simple calculations show that if all of the coal plants submitted the same bid price, so that they were run randomly, generation costs would be approximately 50 percent higher than they are with economic dispatching.

Related to the above point, if a discriminatory auction were implemented with daily bidding and the generators submitted flat bid functions, customers would no longer receive accurate signals of the price of consuming electricity at different times of day. Further simple calculations based on prices during a typical day and the slopes of the linear demand equations estimated in Wolfram (1996) indicate that if there were one price during a day instead of 48 separate prices, deadweight losses would amount to less than 0.1 percent of the typical day's revenues. That small efficiency loss is driven by the inelastic short-run demand for electricity. If over time consumers learn to react to pricing signals and demand is more elastic, the potential distortions from uniform pricing would increase.

The OFFER report also identified a third potential source of inefficiency from discriminatory auctions. Generators such as National Power and PowerGen who own a diverse portfolio of plants are presumably well equipped to identify the plants likely to be marginal and can bid all of their plant's in at that level. By contrast, entrants with fewer plants and, therefore, less information on the cost of the potentially marginal plants, would need to submit low bids in order to avoid being left out of the dispatch. Though such an effect seems plausible, it is harder to quantify the likely response of entry to uniform pricing. Compared to the likely inefficiencies engendered by a discriminatory auction, therefore, the inefficiencies created by strategic bidding seem low.

APPENDIX

This appendix formalizes the assertion that the generator with more inframarginal capacity will submit higher bids and that its incentive to submit a high bid is increasing in the amount of inframarginal capacity it owns. The exposition takes off from von der Fehr and Harbord (1993) and (1992) who develop a model of the UK electricity spot market as a first-price sealed-bid auction. They assume bidders have perfect information about their own and their competitors' costs. They demonstrate that because the suppliers face conflicting incentives to bid high in order to set a high price and bid low to ensure that their plant is called, no pure strategy bidding equilibrium exists.[1] For the case of two generators with equal capacities and constant marginal costs, they are able to derive a unique mixed strategy equilibrium. They show that the bid distribution for the generator with higher costs will first-order stochastically dominate the other bidder's distribution. They assume, however, that the two generators have equal capacities. In this appendix, I modify their analysis to show that when the generators have equal marginal costs, if one of the generators has more inframarginal capacity than the other, he will on average submit higher bids than the other generator.

Assume that there are two generators, 1 and 2. Generator 1 has one unit of capacity with constant marginal cost c. Likewise, generator 2 has one unit of capacity with constant marginal cost c, but he also has m (where $m > 0$) additional units of capacity with marginal costs equal to zero. Demand is assumed to be stochastic and varies between $m+1$ and $m+2$ with probability π and $(1-\pi)$, respectively ($0 < \pi < 1$). In other words, generator 2's m units with zero marginal costs are always used and depending on demand, either one or both of the generators' units with marginal costs equal to c are used. I assume that the generators simultaneously submit prices p_1 and p_2 for their two units with marginal costs c before the level of demand is realized. The two units are ranked according to the submitted prices and once demand is realized, the marginal unit sets the price for all units used in that period. The generator offer prices are constrained to be below some price p^{max}. For instance, p^{max} could be interpreted as an implicit maximum price imposed by regulatory constraints (see Wolfram, 1996).

[1] The incentive to bid high in order to set a high price is driven by the fact that the units for which the generators submit bids are so large that there is a positive probability that a given unit will set the marginal price.

The following proposition sets out the optimal mixed-strategies that the two generators will play in this game:

Proposition 1: There exists a unique mixed-strategy Nash equilibrium in which each generator's strategy is to play $p \in [p^{min}, p^{max}]$ according to the following probability distributions:

$$F_1(p) = \begin{cases} \dfrac{1-\pi}{1-2\pi}\left(\dfrac{p-c}{p^{\max}-c}\right)^{\frac{(1-2\pi)(m+1)}{\pi}} - \dfrac{\pi}{1-2\pi} & when \quad \pi \neq \dfrac{1}{2} \\ \ln\left(e\cdot\left(\dfrac{p-c}{p^{\max}-c}\right)^{m+1}\right) & when \quad \pi = \dfrac{1}{2} \end{cases}$$

and

$$F_2(p) = \begin{cases} \dfrac{1-\pi}{1-2\pi}\left(\dfrac{p-c}{A^{\frac{m}{m+1}}(p^{\max}-c)}\right)^{\frac{(1-2\pi)}{\pi}} - \dfrac{\pi}{1-2\pi} & when\ p < p^{\max}\ and\ \pi \neq \dfrac{1}{2} \\ \ln\left(e^{\frac{1}{m+1}}\cdot\dfrac{p-c}{(p^{\max}-c)}\right) & when\ p < p^{\max}\ and\ \pi = \dfrac{1}{2} \end{cases}$$

and $F_2(p^{max}) = 1$, where $A = \left(\dfrac{1-\pi}{\pi}\right)^{\frac{\pi}{1-2\pi}}$.

Proof: It is straightforward to show that there is at most one generator who plays p^{max} with positive probability (generator 2) and that no generator plays any price $p < p^{max}$ with positive probability. (See von der Fehr and Harbord, 1992, lemmas 1 to 4. The arguments they use extend easily to the case at hand.) Furthermore, if p^{min} is the lowest price in either generators' strategy space, it is clear that the other generator would never want to choose a price lower than p^{min}.

The expected payoff to generator 2 from playing $p \in [p^{min}, p^{max}]$ is:

$$\Phi_2(p) = \pi(1-F_1(p))\cdot((m+1)p-c) + \pi\int_c^p mxf_1(x)dx$$
$$+ (1-\pi)F_1(p)((m+1)p-c) + (1-\pi)\int_p^{p^{\max}}((m+1)x-c)f_1(x)dx$$

which implies that

$$\Phi_2'(p) = \pi\left(m+1-f_1(p)(p-c)\right)+(1-2\pi)(m+1)F_1(p).$$

Using the fact that $\Phi_2'(p)=0$, it follows that

$$f_1(p) = \frac{m+1}{p-c}\left(1+\frac{1-2\pi}{\pi}F_1(p)\right).$$

Using the fact that $F_1(p^{max}) = 1$, we can derive the following unique solution to the above linear differential equation:

$$F_1(p) = \begin{cases} \dfrac{1-\pi}{1-2\pi}\left(\dfrac{p-c}{p^{\max}-c}\right)^{\frac{(1-2\pi)(m+1)}{\pi}} - \dfrac{\pi}{1-2\pi} & \textit{when} \quad \pi \neq \dfrac{1}{2} \\ \ln\left(e\cdot\left(\dfrac{p-c}{p^{\max}-c}\right)^{m+1}\right) & \textit{when} \quad \pi = \dfrac{1}{2} \end{cases}$$

Evaluating $F_1(p)$ at 0 implies $p^{\min} = \alpha^{\frac{1}{m+1}}p^{\max}+\left(1-\alpha^{\frac{1}{m+1}}\right)c$. Note that if $F_2(p)$ is derived in a similar manner (*i.e.* using $F_2(p) = 1$ as the upper limit), the distribution implies a value $p_2^{\min} = \alpha p^{\max}+(1-\alpha)c < p^{\min}$. It is clear, however, that generator 2 would never want to offer a price lower than the lowest price generator 1 ever plays. Instead, the optimal distribution for generator 2 is derived as follows: The expected payoff to generator 1 from playing $p \in [p^{min}, p^{max}]$ is:

$$\Phi_1(p) = \pi(1-F_2(p))\cdot(p-c)+(1-\pi)F_2(p)(p-c)+(1-\pi)\int_p^{p^{\max}}(x-c)f_2(x)dx$$

which implies that

$$\Phi_1'(p) = \pi\left(1-f_2(p)(p-c)\right)+(1-2\pi)F_2(p).$$

Using the fact that $\Phi_1'(p)=0$, it follows that

$$f_2(p) = \frac{1}{p-c}\left(1+\frac{1-2\pi}{\pi}F_2(p)\right).$$

Using the fact that $F_2(p^{min}) = 0$, we can derive the following unique solution to the above linear differential equation:

$$F_2(p) = \begin{cases} \dfrac{1-\pi}{1-2\pi}\left(\dfrac{p-c}{A^{\frac{m}{m+1}}\left(p^{\max}-c\right)}\right)^{\frac{(1-2\pi)}{\pi}} - \dfrac{\pi}{1-2\pi} & \text{when } p < p^{\max} \text{ and } \pi \neq \dfrac{1}{2} \\ \ln\left(e^{\frac{1}{m+1}} \cdot \dfrac{p-c}{\left(p^{\max}-c\right)}\right) & \text{when } p < p^{\max} \text{ and } \pi = \dfrac{1}{2} \end{cases}$$

We also know that the highest value of p that generator 2 will ever submit is p^{max} implying that $F_2(p^{max}) = 1$. QED

It is straightforward to show that $F_2(p)$, the optimal distribution for the generator with the inframarginal capacity, first order stochastically dominates $F_1(p)$. It is also straightforward to show that $F_2(p)$ is decreasing in m, implying that the bigger generator's incentive to submit a high price is increasing in the amount of inframarginal capacity it owns.

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Table 1: Summary Statistics
Data from January, February, March, April, July, November 1992, 1993, 1994

	Mean	Std. Dev.	Observations
BID *(£ per MWH)*	64.0	113.8	65775
between generating units		75.7	207
within generating units		80.2	3 to 537
MARGINAL COST *(£ per MWH)*	22.8	14.9	65775
MARKUP = BID/MARGINAL COST *(percent)*	226	290	65775
between generating units		184	207
within generating units		219	3 to 537
AVAILABLE MEGAWATTS BELOW 1 *(MWs)*	11874	6170	64689
between generating units		6413	207
within generating units		2044	3 to 537
AVAILABLE MEGAWATTS BELOW 2 *(MWs)*	11586	6077	64689
ACTUAL AVAILABLE MEGAWATTS BELOW (MWs)	11538	6092	64689
between generating units		6013	207
within generating units		2497q	3 to 537
DAILY AVG. PREDICTED DEMAND *(GWs per hour)*	32.6	4.5	544

Note: Summary statistics for the first six variables reflect observations by generating unit from every day covered by the data set. The information captured by *DAILY AVG. PREDICTED DEMAND* only varies by day and hence the summary statistics reflect fewer observations.

Table 2: Average Bid by Generating Company and Fuel Type

	National Power			PowerGen			Other		
Unit Type:	Avg. Bid	Megawatts	Obs.	Avg. Bid	Megawatts	Obs.	Avg. Bid	Megawatts	Obs.
Nuclear	--	--	0	--	--	0	0.15 (1.23)	180 (882)	15390
France & Scotland	--	--	0	--	--	0	6.23 (4.04)	2658 (268)	3578
CCGT	9.86 (1.47)	609 (217)	268	7.29 (4.66)	1236 (359)	976	2.17 (4.71)	1058 (701	892
Coal	19.8 (15.1)	16118 (1869)	24531	18.6 (9.3)	9644 (1236)	13230	--	--	0
Pumped Storage	--	--	0	--	--	0	31.6 (10.4)	1711 (221)	5128
Oil	26.5 (4.8)	416 (616)	2104	73.3 (131)	811 (309)	2656	--	--	0
Gas	155 (43)	1233 (161)	6893	213 (224)	358 (119)	7026	--	--	0
Constrained-On	62.9 (59.4)	965 (352)	3961	98.6 (170)	2405 (905)	4130			

Table 3: Bid Markups by Fuel Type and Generating Company
Dependent Variable: *ln(BID) - ln(MARGINAL COST)*

	Coefficient	Robust Std. Er.	Coefficient	Robust Std. Er.
CCGT	-1.04	0.05	-1.11	0.06
Oil	0.52	0.15	0.52	0.15
Gas	0.99	0.15	1.00	0.15
National Power*CCGT	0.48	0.04	0.46	0.03
National Power*Coal	0.01	0.06	0.01	0.06
National Power*Oil	0.36	0.14	0.38	0.14
National Power*Gas	0.28	0.15	0.39	0.13
Constrained On	0.93	0.17	-0.05	0.18
National Power*Constrained-On	-0.08	0.18	0.95	0.17
ln(DAILY AVG. PREDICTED DEMAND)			-0.29	0.05
Sunday			0.005	0.004
Monday			0.040	0.010
Tuesday			0.058	0.011
Wednesday			0.055	0.011
Thursday			0.050	0.011
Friday			0.041	0.010
Observations	65775		65775	
R^2	0.453		0.487	

Note: The omitted fuel type is coal, and, in the second specification, the omitted day of the week is Saturday. The second specification also includes a dummy for each month covered by the data set. Standard errors are adjusted for the presence of heteroskedasticity and serial correlation within a generating unit.

Table 4: Bid Markups by Available Inframarginal Capacity - Measure 1

Dependent Variable: *ln(BID) - ln(MARGINAL COST)*

	Coefficient	Robust Std. Er.	Coefficient	Robust Std. Er.
ln(AVAILABLE MEGAWATTS BELOW 1)	0.19	0.05	-0.06	0.04
ln(DAILY AVG. PREDICTED DEMAND)	-0.67	0.10	-0.36	0.08
Sunday	-0.011	0.007	-0.003	0.005
Monday	0.090	0.014	0.045	0.010
Tuesday	0.110	0.016	0.060	0.012
Wednesday	0.109	0.016	0.052	0.012
Thursday	0.106	0.016	0.050	0.012
Friday	0.091	0.014	0.047	0.011
Generating unit Fixed Effects?	NO		YES	
Observations	64689		64689	
R^2	0.050		0.675	

Note: In both specifications, the omitted day is Saturday and dummy variables for each month covered by the data set were included. Standard errors are adjusted for the presence of heteroskedasticity and serial correlation within a generating unit.

Table 5: Bid Markups by Available Inframarginal Capacity
Measure 2 - OLS and IV
Dependent Variable: *ln(BID) - ln(MARGINAL COST)*

	Coefficient	Robust Std. Er.	Coefficient	Robust Std. Er.
ln(AVAILABLE MEGAWATTS BELOW 2)	0.009	0.017		
ln(ACTUAL AVAILABLE MEGAWATTS BELOW)			0.020	0.021
ln(DAILY AVG. PREDICTED DEMAND))	-0.33	0.04	-0.33	0.04
Sunday	-0.002	0.003	-0.001	0.003
Monday	-0.001	0.002	-0.001	0.002
Tuesday	0.015	0.002	0.015	0.002
Wednesday	0.012	0.002	0.012	0.002
Thursday	0.009	0.002	0.009	0.002
Generating unit-Month-Weekend Fixed Effects?	YES		YES	
Estimation Method	OLS		IV	
Observations	64689		64091	
R^2	0.943		——	

Note: In the first two specifications, the omitted weekend day is Saturday and the omitted weekday is Friday. Standard errors are adjusted for the presence of heteroskedasticity and serial correlation within a generating unit.

Table 6: Fraction of Generating Units for which the Bid Changes by Day of Week

	Fraction	Absolute Value of Change (percent)	Obs.
Monday	0.47	0.07	8205
Tuesday	0.19	0.02	9482
Wednesday	0.20	0.02	9520
Thursday	0.22	0.02	9701
Friday	0.21	0.03	9580
Saturday	0.25	0.08	8098
Sunday	0.14	0.04	7858

Table 7 Bid Markups by Available Inframarginal Capacity
Measure 2 - OLS and IV
Bids Higher than Maximum Marginal Price Excluded
Dependent Variable: *ln(BID)* - *ln(MARGINAL COST)*

	Coefficient	Robust Std. Er.	Coefficient	Robust Std. Er.	Coefficient	Robust Std. Er.
ln(AVAILABLE MEGAWATTS BELOW 2)	0.025	0.016				
ln(ACTUAL AVAILABLE MEGAWATTS BELOW)			0.042	0.020	0.061	0.030
ln(DAILY AVG. PREDICTED DEMAND$_t$)	-0.32	0.04	-0.31	0.04	-0.34	0.05
Sunday	-0.004	0.003	-0.003	0.004		
Monday	0.000	0.002	0.000	0.002		
Tuesday	0.015	0.002	0.015	0.002		
Wednesday	0.011	0.002	0.011	0.002		
Thursday	0.005	0.002	0.005	0.002		
Generating unit-Month-Weekend Fixed Effects?	YES		YES		YES	
Estimation Method	OLS		IV		IV	
Observations	55672		55083		15037	
					Mondays and Saturdays only	
R^2	0.907		-----		-----	

Note: In the first two specifications, the omitted weekend day is Saturday and the omitted weekday is Friday. Standard errors are adjusted for the presence of heteroskedasticity and serial correlation within a generating unit.