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ScienceDirect
International Journal of Industrial Organization
25 (2007) 1233 – 1268
International Journal of Industrial Organization
www.elsevier.com/locate/econbase

Bidding asymmetries in multi-unit auctions: Implications of bid function equilibria in the British spot market for electricity ☆

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Received 16 October 2005; received in revised form 21 September 2006; accepted 3 October 2006
Available online 22 December 2006

Abstract

This paper introduces and tests Bid Function Equilibria (BFE) in the British spot market for electricity. BFE extend von der Fehr and Harbord's (1993) multi-unit auction model of wholesale electricity markets by allowing firms to have heterogeneous costs for different generating units. Pure-strategy equilibria in BFE predict asymmetric bidding by producers: a single firm (the "price-setter") bids strategically while other firms ("non-price-setters") bid their costs. We test for asymmetries in firms' bid functions in the British spot market between 1993 and 1995 and find strong empirical support for the theory. We conclude that BFE have important implications for the design and governance of electricity markets.

JEL classification: L13; L94; L50

Keywords: Electricity; Multi-unit auctions; Bid function equilibrium; Asymmetry; England and Wales

☆ We would like to thank the editor, two anonymous referees, Ariel Pakes, Steve Berry, William Hogan, Gary Biglaiser, David Guilkey, Claudio Mezzetti, Bill Vogt, Miles Light, Bella Silverman, Stan Reynolds, David Reiley and seminar participants at Yale University, the Harvard/MIT IO Seminar, Carnegie-Mellon University, the Harvard University Seminar in Economic Theory, and the Duke/UNC Micro Theory Seminar. The views and opinions expressed here are those of the authors and may not necessarily reflect the views and opinions of Wood Mackenzie, Inc. or any of its clients.
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doi:10.1016/j.ijindorg.2006.10.001

1. Introduction

Within the United States and throughout the world, the deregulation of wholesale electricity markets is well underway. Despite the consensus that these markets can generally benefit from competition, concerns that deregulated energy markets are especially vulnerable to market power continue to persist (Borenstein et al., 2002).[1] In the United States, the Federal Energy Regulatory Commission (FERC) has prescribed a universal wholesale market design which it hopes will be less susceptible to market power and manipulation.[2] Despite the FERC's laudable intentions, there is concern over whether regulators have an accurate understanding of market equilibrium in these markets.

In this paper, we introduce and test Bid Function Equilibria (BFE), a model of firm behavior in wholesale electricity markets. BFE were developed by Crespo (2001) to extend von der Fehr and Harbord's (1993) multi-unit auction model of wholesale electricity markets by allowing firms to have heterogeneous costs for the different generating units they control.[3] This has the advantage of better reflecting the institutional reality of most wholesale electricity markets and clarifying the implications of multi-unit auction theory for firms' bid functions.[4] The primary implication of BFE is that behavior is *asymmetric*: the firm that sets the clearing price (the "price-setter") behaves strategically while all other firms ("non-price-setters") bid close to their marginal costs. This has important implications for the nature of markups over costs ('bid markups') across firms in a wholesale market equilibrium. We test these implications in the England and Wales (E&W) spot market for electricity.

Figs. 1 and 2 provide examples of asymmetric bidding in E&W data. They show the marginal costs and bids for each generating unit by each producer in the E&W market on two days: November 28, 1993 and October 19, 1995. Bids for the individual generating units have been aggregated as they would by the National Grid Company (NGC) to form an aggregate supply curve. Also shown is the maximum (across 24 half-hour periods) daily demand (load) on each day. In Fig. 1, National Power is the price-setter for the majority of high-demand periods. The top panel in the figure shows the aggregate supply curve at all loads while the bottom panel focuses on the aggregate supply curve near the maximum load. While all producers are bidding close to or below marginal cost for units far to the left of the maximum load, only National Power is bidding significantly above cost adjacent (and to the left) of the maximum load.[5] The picture reverses, however, in Fig. 2. Here, PowerGen is the price-setter for the majority of high-demand periods and it is they, not National Power, that is bidding above costs to the immediate left of the maximum load.

Our results use E&W data from January 1, 1993 to December 31, 1995 and demonstrate strong support for the theory. First, using variation in bids for individual generators across time, we find

[1] See also Wolfram (1999), Wolak and Patrick (2001), Sweeting (2005), and Hortacsu and Puller (2006). Wolak (2005) provides an overview of the recent regulatory experience in wholesale electricity markets.

[2] Federal Energy Regulatory Commission White Paper: Wholesale Power Market Platform (Issued April 28, 2003).

[3] Independently, Garcia-Diaz and Marin (2003) developed a similar model tailored to the Spanish whole sale electricity market. We discuss the differences between our respective contributions below.

[4] Homogenous marginal costs for a firm's generating units eliminate incentives to increase profit on (low-cost) inframarginal units by submitting high bid prices for (higher-cost) marginal units that forms the basis for strategic bidding by the price-setter in a BFE. Given that producers in most electricity markets mainain a portfolio of generation capacity with heterogeneous costs, we think understanding such incentives may be improtant.

[5] Note in particular that NP's units that serve peak demand in Fig. 1 have marginal costs less than those of rival generators.

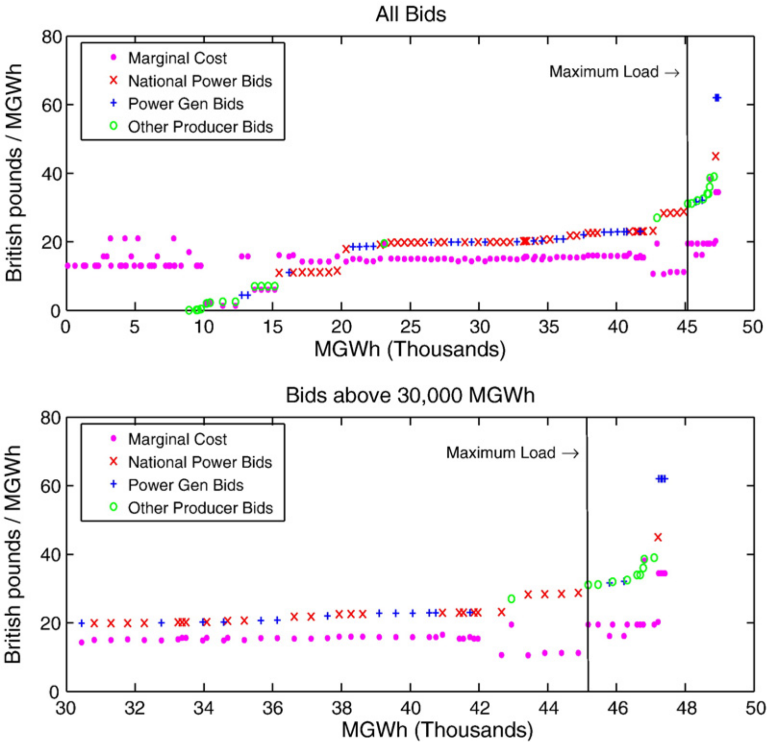

Fig. 1. Bid functions and costs, November 28, 1993. National Power is the price-setter in high-demand periods.

strong and persistent asymmetries when firms do and do not set prices. For example, the estimated effects of infra-marginal capacity, a key strategic factor, impact bids as predicted by BFE and are far stronger for the price-setting firm than for non-price-setting firms. We also use BFE to simulate market equilibria and find evidence of strong incentives to exploit capacity constraints in instances of high demand. When the potential costs of such strategies in the England and Wales market are incorporated, the theory predicts bid markups in periods of peak demand of 22–23%, very close to those estimated by Wolfram (1998) and Wolfram (1999) in the same market.

Our findings have important implications both for the design of electricity markets and the mitigation of market power in these markets. First, BFE help explain the level of bid markups under conditions when the market is not capacity-contained. In these instances, while our estimates of markups are significant, they are less than 30% or more by which average costs of generation exceed marginal costs. This is true despite the relatively concentrated nature of the England and Wales market in the period we study. In instances of high demand, however, our results indicate the potential for exploiting capacity constraints. It is during these periods that the potential for, and consequences of, market power are the greatest. Priority should therefore be given to controlling market power during the extreme cases when one firm possesses incentives to exploit capacity constraints. Finally, simulations show that mitigation policies that *target* specific generating units (e.g. intermediate versus baseload capacity) can significantly enhance market performance.

These results complement other research applying oligopoly models to wholesale electricity markets. In general, this research tends to take one of two approaches. The first approach assumes that firms can make continuous supply decisions. Schmalensee and Golub (1985) and Borenstein

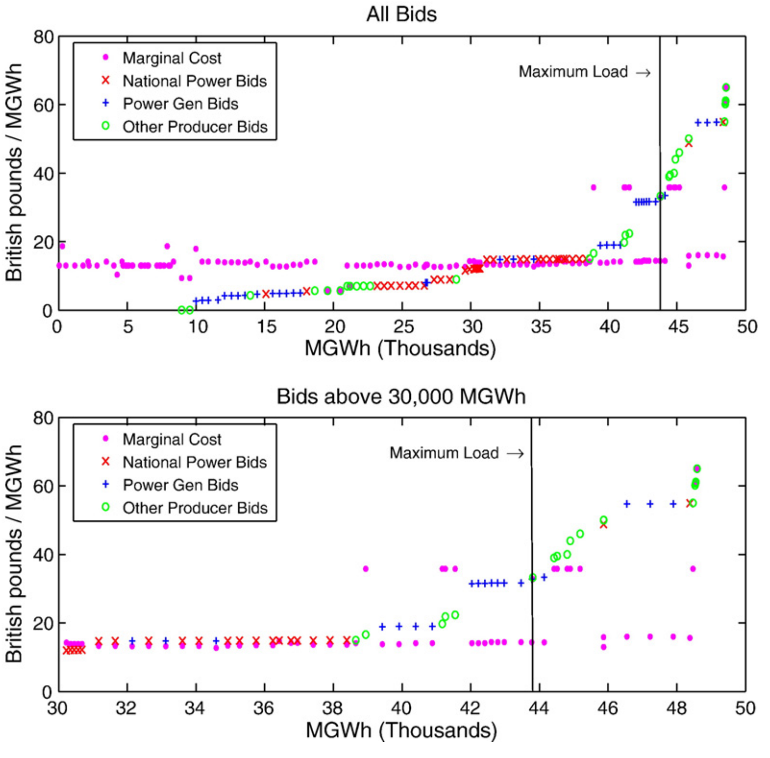

Fig. 2. Bid functions and costs, October 19, 1995. PowerGen is the price-setter in high-demand periods.

and Bushnell (1999), for example, analyze the potential for market power in wholesale electricity markets using a model of static Cournot competition. Fabra and Toro (2005) and Puller (2006) extend the Cournot approach to consider dynamic (tacitly collusive) equilibria. An alternative strand applies models of multi-unit auction theory, but with continuous bid functions. These models, developed by Klemperer and Meyer (1989) and denoted Supply Function Equilibria (SFE), were first applied to electricity markets by Green and Newbery (1992). Subsequent applications include Green (1996), Newbery (1998), Green (1999), Baldick, Grant, and Kahn (2004), Genc and Reynolds (2005), and Baldick and Hogan (2006). Models in this strand of the literature generally predict markups for all producers, whether or not they set the price.

The second approach, characterized by von der Fehr and Harbord (1993), also builds models of multi-unit auctions, but acknowledges the discreteness inherent in electricity supply. von der Fehr and Harbord (1993), for example, build a model with N firms, each producing a given capacity k_n at constant marginal cost c_n and submitting bids to serve an inelastic market demand, d. This approach has since been extended to allow for elastic demand, within-firm cost heterogeneity, long-lasting bids, and repeat play (Brunekreeft (2001), Garcia-Diaz and Marin (2003), Fabra (2003), Fabra, von der Fehr, and Harbord (2006)).[6]

[6] A small but growing literature generalizes both of these approaches by solving for equilibrium to a game modelled closely to the institutional details of a particular wholesale electricity market, particularly the importance of network transmission constraints and consequent geographic market power. See Borenstein, Bushnell, and Stoft (2000), Joskow and Tirole (2000), Gilbert, Neuhoff, and Newbery (2004), and Escobar and Jofre (2005) for more.

Of these, BFE is closest to the work independently developed by Garcia-Diaz and Marin (2003). They also allow for complete information, deterministic demand, and increasing step cost functions and find that pure strategy equilibria are characterized by firm asymmetries. Where we differ is in our uses of the model and our test of its implications on observational data. Garcia-Diaz and Marin (2003) compare equilibrium prices to Cournot prices (finding the former to be lower), show how equilibrium prices vary with aggregate demand elasticity, and analyze the consequences of mergers in an application modelled on the Spanish electricity market. We characterize equilibrium bid functions, test the implications of the theory using data from the England and Wales electricity market, and analyze the consequences of divestiture in an application modelled on that market. In all cases, our results are clearly complementary.[7]

Our results are also related to a large empirical literature analyzing wholesale electricity markets. Many studies, including Wolfram (1999) and Puller (in press), compare estimates of market power with that predicted by theory, while others, including Wolak (2000), Wolak (2003), Hortacsu and Puller (2006), and Sweeting (2005), analyze whether observed behavior is consistent with short-run profit maximization.[8] These often find markups not only for the price-setter, but also for non-price-setters. In part, this can be explained by the necessity for firms in the E&W market to submit bid functions that are fixed for a day, a topic we discuss in Section 3.3. That being said, our results should not be interpreted too strongly– there is ample evidence in our data that both price-setters and non-price-setters bid above marginal cost– but rather that such incentives may be stronger for the price-setter than non-price-setters. Integrating the asymmetric implications of BFE with those of alternative theories of electricity supply would be useful.

The remainder of this paper is organized as follows. Section 2 reviews the theoretical literature on multi-unit auction models of wholesale electricity markets and contrasts the results of these models with other approaches taken in the literature. Section 3 presents the theory in more detail and explores its implications for the England and Wales market. Section 4 describes the available data and Section 5 presents the econometric specification and results. Simulations of BFE are presented in Section 6, and Section 7 concludes.

2. Multi-unit auction models of electricity markets

2.1. Overview

Ausubel and Cramton (1997), following a line of analysis dating to Wilson (1979), note that in markets involving the sale of multiple units of a homogenous good at a uniform price, buyers have an incentive to “reduce demand,” or understate their valuations for some units of a good. If their (low) bids set the market price, they earn a greater surplus on all units bought. In electricity markets, analogous incentives imply sellers “reduce supply”, trading off higher markups on infra-marginal units against lost revenue on marginal units. von der Fehr and Harbord (1993) were first to take this approach in electricity markets. Building on this literature, Crespo (2001) introduced Bid Function Equilibria to formalize these incentives and characterize the set of pure strategy Nash equilibria. The basic model is one of duopoly in a multi-unit auction under complete

[7] The analysis of Fabra, von der Fehr, and Harbord (2006) contrasting uniform and discriminatory auctions is also similar to BFE, but, like von der Fehr and Harbord (1993), requires all of a firm’s generating units to have the same marginal costs.

[8] Bunn and Martoccia (2005) conduct a recent analysis in this line on the England and Wales market.

information, and extensions are derived to accommodate important aspects of electricity markets. Subsequent papers have further generalized this approach (Brunekreeft (2001), Garcia-Diaz and Marin (2003), Fabra (2003), Fabra, von der Fehr, and Harbord (2006)).[9]

2.2. What makes multi-unit auction theory different from other approaches?

The discrete multi-unit auction approach taken by BFE and other papers in this line of research differ in two important ways from the approach taken by Cournot or (especially) SFE.[10] Like SFE, producers are permitted to submit bid functions which are aggregated to obtain an industry supply curve. Unlike SFE, however, BFE incorporate the discreteness inherent in electricity supply: firms submit separate bids for each of their (discrete) generating units.

The assumed information structure of BFE differs from other auction theories and from SFE. BFE assume complete information regarding each firm's marginal cost schedule as well as market demand. While these are strong assumptions, they are arguably benign when applied to electricity markets. First, electricity markets often clear on a day-ahead basis using a forecast of demand that is announced in advance. Second, for most generation units, and especially price-setting generation units, there is often very good information regarding efficiency levels and fuel (commodity) prices that determine a unit's marginal cost. In many electricity markets, including the England and Wales market considered in this paper, studies take demand and cost information as given (Green and Newbery, 1992; Borenstein and Bushnell, 1999; Wolfram, 1999).[11] Appendix B describes the England and Wales electricity market studied in this paper in more detail.

The combination of complete information and a discrete action space has important consequences for strategic interaction in equilibrium. Like the literature on multi-unit auctions (without complete information), generators have the incentive to inflate bids in an effort to increase the marginal price paid to all generating units. BFE differ from these theories, however, in predicting *asymmetric* bidding behavior across producers. In particular, BFE predict that for a given level of demand, a single firm (the "price-setter", hereafter PS) chooses strategies aimed at setting the clearing price. The Nash equilibrium response of all other firms ("non-price-setters", hereafter NPS) is to choose a bid function that is outcome-equivalent to bidding their marginal costs. In essence, BFE imply that the intuition of the multi-unit auction theory is correct, *but only for the price-setter.*[12]

The intuition for asymmetric bidding is easily understood. In a uniform price multi-unit auction for a homogenous good, a high price is a public good. Even with identical symmetric firms, symmetric equilibria break down due to the standard free-riding problem: NPSs earn greater profit by increasing output in response to the reduction in output (and higher common

[9] As noted in the Introduction, the theoretical analysis in BFE is quite similar to the multi-unit auction theory developed independently by Garcia-Diaz and Marin (2003).

[10] Fabra, von der Fehr, and Harbord (2002) provide a nice non-technical overview of alternative modeling approaches in electricity markets.

[11] Indeed, these costs are often available in public documents or can be purchased by companies that collect generator operating information.

[12] This insight is a general feature of the discrete multi-unit auction approach and is present in the literature as far back as von der Fehr and Harbord (1993, Proposition 3). It appears, however, not to be uniformly appreciated by subsequent work. Wolfram (1998), for example, tests multi-unit auction theory in the British spot market but makes no mention of nor tests for asymmetries between bid functions of those that do and do not set the clearing price. Fabra (2003), by contrast, suggests that in a dynamic setting firms may alternate being "low" and "high" bidders.

price) induced by the PS. With uncertainty, firms cannot be sure they will be the price-setter and all firms bid markups; with complete information, however, firms act as Bertrand competitors (with asymmetric costs) for the marginal unit. This drives prices to the marginal cost of the NPS' first excluded unit. These results are derived in further detail in the following section.

3. Bid function equilibria

3.1. Overview

The basic model is that of a duopoly in a multi-unit auction of complete information. Each firm submits a bid function giving the price at which it is willing to sell the output from each of its production units. The bid functions are aggregated, and the uniform clearing price equals the bid price of the unit for which the inelastic demand intersects the aggregate bid function. The resulting Bid Function Equilibrium is a Nash equilibrium consisting of the firms' bid functions along with their outputs and the market price. Even with identical firms, the equilibrium of the model is *asymmetric*. One of the firms acts as a price-setter in that it bids some units above marginal cost thereby raising the price above the competitive level. The other firm, which is referred to as the non-price-setter, submits marginal cost bids or bids that are outcome-equivalent to marginal cost bids.

3.2. Description of the basic model

The game is a duopoly with complete information. The auction demand, M, is a positive integer which we assume to be even. Each firm has M production units with the size of the units normalized to be one.[13] The total and marginal costs for q units are denoted $C(q)$ and $c(q)$, respectively. The marginal cost function is a step function which increases at an increasing rate.[14] For any integer n, the marginal cost function c is constant on the interval $(n-1, n]$. Each firm submits a bid function that gives the price at which it is willing to supply the output from each of its production units. The number of units accepted is determined according to the M lowest bid prices. The compensation for each unit sold is the uniform clearing price.[15] The solution concept is the usual Nash equilibrium. This is referred to as a Bid Function Equilibrium.

3.2.1. Why MC bidding is not an equilibrium

The explanation why marginal cost bidding is not an equilibrium provides insights into the underlying features of the model. Marginal cost bidding has each firm producing half of the

[13] Capacity constraints are assumed away in this paper. In the presence of capacity constraints, BFE can predict corner solutions in which the equilibrium price is infinite (or equal to a price cap). While historically relevant in some electricity markets (e.g. California), either formal or informal regulatory oversight (e.g. ex post windfall taxes) typically precludes such outcomes. In practice, what is important is not that each firm can supply the whole market, but that each firm can supply any quantity that can be effectively withdrawn by its rivals. We discuss this issue further in Section 6.

[14] This assumption is based on inspection of actual marginal cost curves, particularly for units that are marginal in periods of peak demand. Green and Newbery (1992) make a similar assumption in studying the England and Wales market.

[15] The lower cost unit is assumed to be taken in the case of tied bids. If the two units have the same marginal cost, then each firm sells one-half unit. The salient features of BFE are unchanged using alternative assumptions on the tying rule (Crespo, 2001, p.6).

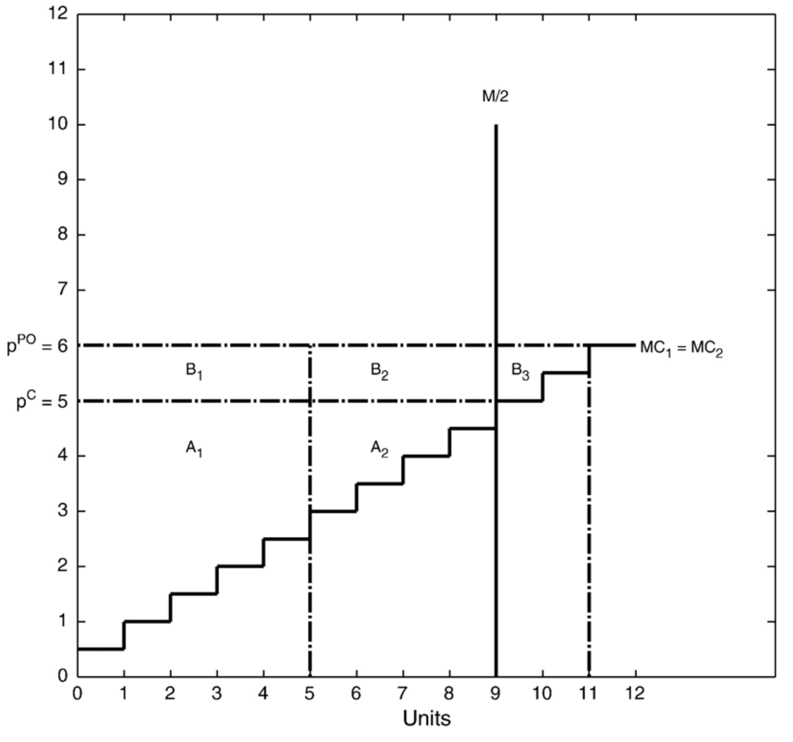

Fig. 3. Pricing out units: an example. This figure demonstrates the profitability of "pricing out" units in a uniform-price, multi-unit auction. Two firms, {1,2}, have symmetric marginal-cost functions, $MC_1 = MC_2$, and face an inelastic demand, $M = 18$. Each would produce $q_0 = M/2 = 9$ at price $P^C = 5$ by bidding their units at cost. Suppose firm 1 deviates from this strategy and prices out his last four units by bidding them infinitely high. These would be replaced by the next two cheapest units from each firm and yield price $P^{PO} = 6$. This is a profitable deviation whenever, as here, $B_1 + B_3 > A_2$.

auction demand, which we call the firm's *null quantity* and denote q^0 $(= M/2)$. The market price P is the marginal cost of the first excluded unit, $c(q^0 + 1)$ and each firm's profit is

$$c(q^0 + 1)q^0 - C(q^0).$$

In this case, it is easy to see the profitability of deviating. If one of the firms were to raise its bid on units beyond $q^0 - 1$ to $c(q^0 + 2)$ (or higher), this becomes the clearing price, yielding profits $c(q^0 + 2)(q^0 - 1) - C(q^0 - 1)$. We call this *pricing out a unit*. This is profitable as long as $q^0 > 1$.[16]

Fig. 3 illustrates the general intuition for how firms profit from pricing out units. Two firms, {1,2}, have symmetric marginal-cost functions, $MC_1 = MC_2$, and face an inelastic demand, $M = 18$. Each would produce $q_0 = M/2 = 9$ at price $P^C = 5$ by bidding their units at cost. But if firm 1 deviates from this strategy and prices out his last four units by bidding them infinitely high, these would be replaced by the next two cheapest units from each firm and yield price $P^{PO} = 6$. This is profitable whenever, as here, $B_1 + B_3 > A_2$.

[16] Similarly, bid functions which are non-increasing or which have some units below marginal cost are weakly dominated (Crespo, 2001, p.7). In the remainder of the discussion, we limit our attention to bid functions that are increasing and do not fall below marginal cost and to demand conditions that are sufficiently large to make strategic bidding worthwhile.

3.2.2. Definition of the price-setter

A firm is defined as a *price-setter* if the bid on its last unit accepted for the auction equals the market price. Let q_1 and q_2 denote the quantities that firms one and two produce in equilibrium, and let σ_1 and σ_2 denote their bid functions. Formally, firm i is a price-setter if the market price equals $\sigma_i(q_i)$. Otherwise, a firm is a non-price-setter. To facilitate the presentation of the theory, we also index the null quantity, q^0, by firm, i.e. q_1^0 will be the null quantity of the price-setter and q_2^0 the null quantity of the non-price-setter. Note, however, that for symmetric firms, $q_1^0=q_2^0=q^0$.

It is never an equilibrium for both firms to be price-setters in this setting. To see this, suppose *each* firm in Fig. 1 sets bid prices for its last two units infinitely high, again yielding $P^{PO}=6$. This cannot be an equilibrium as each of these units has marginal cost less than 6. As such, either of the firms could set a bid price of just less than 6 and have its units run, displacing higher-cost units from its rival (as well as itself) and increasing profits. In a multi-unit environment with complete information, competition at the margin is like Bertrand competition with homogenous products. Symmetric equilibria break down in this case (except for degenerate cases) and asymmetric equilibria resemble Bertrand competition with asymmetric costs.[17] Lemma 1 in Appendix A formally establishes that the optimal response of one firm when the other is restricting output is to bid its costs. Without loss of generality, we will therefore assume that firm 1 is the (unique) price-setter (PS) and firm 2 is the non-price-setter (NPS).

Lemma 2 in Appendix A goes on to show that in equilibrium, the market price equals the marginal cost of the first extra-marginal unit of the non-price-setter ($P=c(q_2+1)$). This is done in two parts. The first shows that all of the NPS's (firm 2's) units with marginal cost at or below the clearing price are in production. To see this, suppose the converse. Since both the bid function and marginal costs are increasing, non-producing units with $c(q)<P$ must be those immediately above q_2 in marginal cost order. If the NPS switches its bid to $P-\varepsilon$ on unit q_2+1, it now comes into production but, of course, all units sell at the slightly lower price of $P-\varepsilon$. By making ε sufficiently small, the net effect on profit can be made positive. Thus in equilibrium, $P\geq c(q_2+1)$. The second part demonstrates that the incentives of the PS force the price up to $c(q_2+1)$. Since the PS bids units out of production, its last unit produced, or marginal unit, has lower marginal cost than the marginal unit of the NPS. If the bidding yielded a price below $c(q_2+1)$, then the PS could increase the bid on its marginal unit and there would be no change in its units produced. Thus in equilibrium $P\leq c(q_2+1)$. Taken together, these conditions imply $P=c(q_2+1)$.

3.2.3. The price-setter's problem

Having shown that $P=c(q_2+1)$ in equilibrium, we can express the price-setter's optimization problem in terms of the number of units it prices out, denoted k. The outputs of the PS and the NPS are then $q_1=q_1^0-k$ and $q_2=q_2^0+k$; and the price is $c(q^0+k+1)$. Again designating firm 1 as the price-setter, its optimization problem becomes

$$\max_{k_1\in\{0,1,\ldots,q_1^o\}} (q_1^o-k_1)[c(q_2^o+k_1+1)]-C(q_1^o-k_1).$$

[17] This occurs because the price-setter's last included units have lower costs than the non-price-setter's last included units.

This is a standard monopoly pricing problem. Letting $\Delta\pi_1/\Delta k_1$ denote the change in the firms profit as k_1 increases from k_1-1 to k_1, the optimal number of units to price out is the greatest value k_1 for which $\Delta\pi_1/\Delta k_1$ is positive,[18]

$$k_1^* = \max k_1 \in \{0, 1, \ldots, q_1^o\} \text{ such that } (q_1^o - k_1)[\Delta c(q_2^o + k_1 + 1)] \\ -[c(q_2^o + k_1) - c(q_1^o - k_1)] \geq 0. \tag{1}$$

This equation shows that a PS continues pricing out units so long as higher revenues on infra-marginal units, $(q_1^o - k_1)[\Delta c(q_2^o + k_1 + 1)]$, are greater than lost revenue on marginal units, $c(q^o + k_1) - c(q^o - k_1)$. Given the optimal k_1^*, equilibrium quantities and prices are given by $q_1^* = q_1^o - k_1^*$, $q_2^* = q_2^o + k_1^*$, and $P^* = c(q_2^* + 1) = c(q_2^o + k_1^* + 1)$.

3.2.4. Existence and uniqueness of equilibrium bid functions

While the arguments above establish equilibrium outcomes for marginal units, it is the entire *bid function* that must satisfy the definition of a Nash equilibrium.[19] In equilibrium, BFE therefore impose *bounds* on each firm's bid function. Appendix A describes these bounds more fully and establishes the existence of pure-strategy Nash equilibrium bid functions.

While pure-strategy Nash equilibria can be shown to exist, there is no guarantee that they are unique. Indeed, for a given price-setter, there are many candidate bid functions for the price-setter and non-price-setter that satisfy the requirements for equilibrium: any that yield optimal quantities and prices defined by k^*; in Eq. (1) and that do not violate the bounds described in Appendix A qualify. Furthermore, for symmetric firms, there are always at least two (identical) equilibria that differ only in the identity of the price setter.[20]

Despite the lack of uniqueness away from the margin, Lemma 2 in the Appendix ensures equilibrium *outcomes*, (q_i^*, q_j^*, P), are unique at the margin (for a given price-setter). It is for this reason we focus our empirical analysis on these units in what follows.

3.3. Extensions to the basic model

In this paper, we test the implications of BFE in the England and Wales spot market for electricity. There are several unique features of its institutional structure that require extensions of the basic model introduced above.[21] Appendix B describes in more detail these institutions; this subsection describes the extensions to the basic model made (or not made) to accommodate these features of the market.[22]

3.3.1. Multiple demand periods

The basic model assumes that there is a single bid function for each demand period. In the EW electricity market, however, firms must submit a single bid function for all the 48 half-hours in the day. Even in the simplest case of just two demand periods (e.g. "Peak" and "Off-Peak"), bids on

[18] Since marginal cost increases at an increasing rate, the profit function is concave in k_1. It follows that the difference $\Delta\pi_1/\Delta k_1$ is weakly decreasing in k_1, ensuring the tractability of the objective function.

[19] It is possible, for example, to create bid functions with the conditions for equilibrium satisfied for marginal units but not for all units. For example, if the bid price of one of the NPS's extra-marginal units is too high above its marginal cost, the PS may wish to price out additional units in order to raise the clearing price to the bid price of that unit.

[20] If firms are very asymmetric, this duplicity of equilibria can disappear as the large firm may have an incentive to price out units even if the small firm is already doing so. In this case, the only equilibria are those with the large firm as price-setter.

[21] One feature of the E&W market we do not consider in detail is the impact of forward contracts by firms. See Green (1999) and Wolak (2001) for more on this topic.

[22] In the interest of space, we do not prove these properties here. The interested reader is referred to Crespo (2001) for details.

units that are infra-marginal in peak demand periods may be marginal in off-peak periods. Bids on a single unit may therefore be influenced by bounds on bids from each period. Furthermore, there is no guarantee that the PS in peak demand periods is the same as the PS in off-peak periods. This has two consequences for BFE. First, by mixing incentives from different demand periods, it muddies the predictions of the theory below peak demand.[23] In *peak* demand periods, however, this multiplicity of incentives has much less impact as there are no greater periods of demand to influence bid prices for marginal (or extra-marginal) units. Thus, for units which are marginal during periods of peak demand, the incentives facing firms in the multi-period game are very similar to those facing firms in the single-period game. As a result, in the empirical work to follow, while we test the implications of BFE throughout firms' bid functions, we focus especially on analyzing bid functions during peak demand periods.

3.3.2. Uncertainty and bid lumping

While forecast demand is unusually accurate in electricity markets, there are times when realized demand differs significantly from forecast demand. Similarly, shocks to availability due to maintenance and repair are not uncommon in electricity markets. As these sources of uncertainty can impact the firm's bidding behavior, Crespo (2001, pp. 28–33) extends the basic model of Bid Function Equilibria to admit a small probability of an exogenous and random shock to demand and/or availability.

One consequence of this extension is that both the PS and NPSs may bid markups on units that could set the market price in a particular period. This makes BFE more like other theories of electricity supply and muddies the implications of BFE even in the peak demand periods that are the focus of our empirical tests. While this is unfortunate, the institutional structure of the E&W market mitigates some of these concerns. In particular, the market price (SMP) was specifically chosen at the intersection of the aggregate bid curves and *forecast* demand. If actual demand deviated from forecast, an Uplift charge was used to compensate units that were required to run despite not being scheduled in the day-ahead market. Unlike scheduled units, these were paid their bid prices, making the so-called imbalance market similar to a discriminatory auction. This greatly diminishes the incentive of the price-setter in a BFE to bid markups on these units (and might induce the non-price-setter to bid above marginal cost for units that could be extra-marginal). Because bids on marginal units for the PS are generally higher than their marginal costs, BFE predict bids for extra-marginal units as low as possible without reducing the equilibrium price. This implies the PS should bid its extra-marginal units at the same level as its marginal unit, a practice we call "bid lumping".

While uncertainty about rivals' capacity availability could still have an effect on bidding behavior, there were several factors which mitigated its effects. First, upkeep and maintenance that had the potential to keep a generating unit offline for more than a day was typically scheduled ahead of time and often known to rivals. Moreover, unscheduled shocks to availability that persisted more than a day quickly became known to rivals by the units absence and could be accommodated on a day-ahead basis. In practice, this suggests optimal strategy in the E&W market could vary across days, depending on the appropriate assumption about the information structure facing firms. When firms have complete information (as assumed in BFE), we expect to find asymmetries in bidding behavior between the PS and NPSs. Such asymmetries are less likely when demand or capacity is unknown (as assumed in SFE or multi-unit auctions with uncertainty). On balance, our priors are that uncertainty

[23] Furthermore, Crespo (2001, pp. 16–24) shows that pure-strategy Nash equilibria do not always exist in a static game with multiple demand periods. Restricting the strategy space to reflect institutional features in electricity markets (e.g. high start-up costs and *minimum run* times), however, can resolve this issue.

about rival's capacity availability was not sufficient to mute the fundamental implication of bidder asymmetry in BFE, but we defer concluding on this issue until our empirical results.

3.3.3. Multiple firms and firm asymmetries

In the basic model, there are two identical firms. In the EW market, however, there are more than two firms, all of whom differ in their generation portfolios. Each of these extensions can be easily accommodated and are addressed in Crespo (2001). With respect to multiple firms, Crespo (2001) shows that the basic features of the duopoly model are retained. There is still a single price-setter, with all other firms remaining non-price-setters and submitting bid functions outcome-equivalent to marginal cost. With respect to firm asymmetries, these are modelled in Crespo (2001, pp. 15–16) by allowing the amount of production capacity at various marginal cost levels to differ. Extending the model to allow for such differences is straightforward, and the resulting comparative statics results provide useful direction for the empirical work. For example, in a symmetric model, either firm may equally well be the price-setter; with asymmetries, however, firms benefit differently from setting prices. This issue is discussed further in Section 5.

3.3.4. Contract cover

One important feature of the E&W market that we do not incorporate into our analysis is the impact of financial contracts on bidder behavior. In particular, during our sample period National Power and PowerGen, the two largest generators in the E&W market, signed financial contracts with electricity supply (distribution) companies that hedged their exposure to fluctuations in the market price. Green (1999) (in E&W) and Wolak (2000) (in Australia) analyze such hedge contracts in more detail, concluding that they can have an important effect on static bidder behavior by limiting the infra-marginal quantity over which increases in marginal prices can increase profits. Wolfram (1999), and Sweeting (2005) estimate contract cover for the two largest E&W generators of between 70 and 100% for most of the 1990s.

We do not accommodate contract cover in our analysis for several reasons. First, we do not know the level of contract cover for each firm in the E&W market for the years for which we have data. Contract cover varied across producer, day, and even time of day, and we hesitate to base our analysis on estimates that could be significantly (and heterogeneously) mistaken.[24] Furthermore, our key empirical test, that of asymmetries in bidding behavior between PSs and NPSs, does not depend on the amount of contract cover.[25] Finally, and most significantly, despite the presence of significant contract cover, both Evans and Green (2005) and Sweeting (2005) find that bidder behavior in the E&W market is consistent with short-run profit-maximizing behavior *without contracts*.[26]

3.4. Testable implications of BFE

As the last section suggests, there are important differences between the economic environment modelled by Bid Function Equilibria and the England and Wales market in which we test

[24] In his work covering the late 1990s, Sweeting (2005) conducts robustness checks on the level of contract cover by varying the assumed amount of contract cover between 0 and 80% for National Power and PowerGen. Doing the same for our empirical tests had a substantive change only on the estimated impact of capacity below peak demand that, if anything, yielded larger predicted asymmetries in bidding behavior between PSs and NPSs.

[25] By contrast, the simulations in Section 6 do depend on contract cover. These, however, are simply meant to illustrate the implications of the theory, rather than predict specific market outcomes. We discuss this point further there.

[26] Sweeting (2005) concludes that their behavior is consistent either with tacit collusion or an attempt to raise spot market prices to influence future hedging contracts.

Table 1
Summary statistics: bids markups, demand, and fuel types

Variable	All units		Price-setter		Non-price-setters	
	Mean	Standard deviation	Mean	Standard deviation	Mean	Standard deviation
Bids markups						
Across entire bid function						
Bid markup	17.69	86.88	25.23	105.70	14.85	78.43
Log(bid markup)	.96	1.42	1.28	1.58	.83	1.35
For bid functions near peak daily demand						
Bid markup	10.01	23.69	11.42	26.87	9.36	22.05
Log(bid markup)	1.28	1.37	1.46	1.39	1.20	1.35
Daily demand						
Minimum demand (MW)	25,857	4,245				
Maximum demand (MW)	37,796	5,385				
Fraction of generators by fuel types						
Coal	.44	.50				
Nuclear	.18	.46				
Combined cycle gas turb	.14	.35				
Oil	.09	.27				
Coal and oil	.06	.23				
Pumped storage	.04	.19				
Gas/combined oil-gas turbine	.03	.18				
Auxiliary gas turbine	.01	.11				
Other	.03	.17				

Notes: Sample is 141,164 unit days. A generating unit is usually one turbine in a generating plant. Reported means are weighted by capacity due to very high bid prices for (small) reserve capacity. Demand and bid data are from The Electricity Pool. Bid markups are bids less the implied unit marginal cost. Marginal costs are calculated using the observed fuel price and efficiency ratings for each plant in the sample. A list of plants and their efficiency ratings are from the Central Electricity Generating Board Statistical Yearbook. See Appendix C for more. Bids near peak daily demand are within 3000 MW of the peak. Results in the price-setter (non-price-setter) column are for all units owned by the firm(s) that set (did not set) the price at least as many times as any other firm in the 10 highest demand periods in a given day. Other fuel type includes Waste Heat Generation, Hydro, and Unknown fuel types.

it. As a consequence, some of the implications of BFE (e.g. markups for only the price-setter) clearly do not hold in the data (cf. Table 1) and might be better explained by alternative theories of electricity supply. That being said, the fundamental prediction of BFE – of important asymmetries in bidding behavior between price-setters and non-price-setters – is robust and is therefore the focus of our empirical tests.

Implication 1: Bid markups for *marginal* units are higher for the PS than for the NPS, particularly in periods of peak demand.

Implication 1 is the primary implication of BFE. In the basic model, BFE predict that bid markups at the margin are positive for the PS and zero for the NPS.[27] Allowing that multiple demand periods and/or uncertainty about demand or rivals' capacity availability may induce non-marginal cost bids from the NPS, BFE still predict higher bid markups for the PS's marginal units compared to the NPS' marginal units, particularly during periods of peak demand.

Implication 2: Bid markups increase with (a) infra-marginal capacity and (b) the cost differentials between rivals' extra-marginal units more for the PS than for the NPS.

[27] Throughout this section, the price-setter refers to the price-setter for peak demand periods.

Implication 2 focuses on the difference in strategic incentives facing the PS and NPS. As for the previous implication, this prediction is sharpest for marginal units in the peak demand period, but would be expected to hold for other units as well.

The comparative static results embodied in Implication 2 follow directly from the price-setter's optimal strategy described by Eq. (1). As can be seen there, the incentive to price out more units and thereby increase bid markups is greater the greater the number of infra-marginal units on which the additional revenue is earned ($q_0 - k_1$). Similarly, the greater the cost differential for the rivals' infra-marginal units ($\Delta c(q^o + k_i + 1)$), the greater the price increase achieved by pricing out another unit.[28] Modulo the influence of multiple demand periods, the non-price-setter does not face these incentives at the margin. As for Implication 1, allowing for multiple demand periods softens the predictions for the non-price-setter, but still yields the prediction that the effect of strategic considerations should be greater for the PS than the NPS.

Implication 3: The bid function of the PS exhibits *lumping* near the margin.

As described in Section 3.3, when a shock to demand or infra-marginal capacity occurs, the bid function of the PS exhibits lumping near the margin. The practical effect of lumping is that the slope of the PS's bid function should decline in the range of the marginal and extra-marginal units. There is no corresponding effect on the NPS' bid functions.

4. Data

In this section, we describe the data that are used to test the implications of BFE. The key variables described in Section 3 relate bid markups to characteristics of firms' generating portfolios, marginal costs, and bid functions, where the bid markup over unit i for a given bid function is simply the bid price submitted for unit i minus the approximated marginal cost constructed for unit i. Generator portfolio information includes each unit's capacity and the type of fuel that it utilizes and is available from the individual generators and a list published by the Electricity Association. The market bid data and the construction of the marginal cost data are described below. The data are for January 1993 through December 1995.

4.1. Marginal cost data

Due to the nature of electricity generation and the elaborate exchanges of information between generators and regulators prior to deregulation, we are fortunate to have fairly precise estimates of marginal cost for individual generating units. Following Wolfram (1998) and Green and Newbery (1992), we assume that the short run marginal (energy) cost of producing electricity from a fossil fuel plant (oil, coal, and natural gas) depends on the type of fuel the plant burns, the price at which that fuel is purchased, and the efficiency rating of the plant. We are therefore able to approximate the marginal cost curves of the two largest generators, National Power and PowerGen, as well as other firms. Together, these marginal cost curves form the aggregate marginal cost curve for the entire market. The details of this procedure are described in Appendix C.

[28] Note that both the foregone markup on the marginal unit ($c(q^0 + k_1) - c(q^o - k_1)$) and the size of the marginal unit (normalized to 1 in the basic model but allowed to vary with the extension for firm asymmetries) also affects the incentive to price out units. Indeed, Wolfram (1998) found that larger units were less likely to be priced out. Since the empirical specification includes unit-specific fixed effects, the impact of unit size on bidding behavior cannot explicitly be addressed.

4.2. Market data

Market data are made available by The Electricity Pool which provides these services on behalf of the National Grid Company. We have 179,333 observations on pool bids, prices, and quantities during nearly every half-hour of each day from 1993 through 1995. These data include (i) day-ahead demand as forecasted by the National Grid Company, (ii) generator bid functions for each day between 1993 and 1995, (iii) the generation capacity declared available for each unit as provided daily by the generators, and (iv) the identity of the price-setting unit for each half-hour of each day.

Table 1 presents summary statistics for some of the key variables used in the paper.[29] Notice that coal units make up the largest share of fuel types. Other fuel types listed include nuclear, combined cycle gas turbine, oil, combined coal and oil, pumped storage, gas and combined oil-gas turbine, auxiliary gas turbine, waste heat generation, and hydroelectric.[30] The average daily peak demand (MAXDEM) is 37,796 MW and the highest demand in the sample is 48,957 MW. The difference between the average daily peak demand and average daily minimum (MINDEM) demand is 11,899 MW. Definitions and summary statistics for the regressors will be provided in the following sections.

5. Empirical specification and results

The implications of BFE that we test in our data relate a firm's bid markups on its status as a price-setter or a non-price-setter. The identity of the price-setter, however, is clearly a choice variable of the firms in the market. Accordingly, the empirical model consists of two equations, one predicting the probability that a firm is a price-setter during the peak demand period in a day and one for the bid markup on each firm's generating units during each half-hour of that day. We first estimate the price-setter equation and then include the predicted probability of a firm being the price-setter as an explanatory variable in the bid markup equation. To compute the standard errors on the estimated coefficients of the bid markup equation we apply a bootstrap method.

5.1. The price-setter equation

In the basic model with symmetric firms, there are generally n unique equilibrium outcomes, one associated with each firm as the price-setter. As such, the theory does not provide direct guidance about which of these equilibria is being played at a given point in time. In practice, however, firms differ in their generation portfolios and days differ in the forecast level of demand. The profitability to each firm of being the price-setter (and the non-price-setters) will therefore vary across days. The assumption we make here is that there is a latent profitability to each firm from being the price-setter in each day and that the price-setter on a given day is the firm for which that profit is greatest.[31]

[29] We report the capacity-weighted means for bid prices and markups because the unweighted means are greatly influenced by reserve capacity that is bid in at extremely high prices. There are sometimes several of these reserve units associated with a single coal genset. These reserve units, however, are much smaller than the coal units. Hence, they skew the unweighted mean to levels that are not representative of bidding behavior that is actually relevant to the market. Even with such weighting, the reported average bid markups are much larger than the associated log markups. This is merely for convenience; we use the unweighted prices in the empirical analysis.

[30] The auxiliary gas turbines are smaller units that are included in plants of other fuel types, often as reserves. Most of the auxiliary gas turbines in the England and Wales market are found in coal plants.

[31] This would be the case, for example, if the firms chose the Pareto Efficient Equilibrium.

BFE predict that the profitability of being the price-setter depends upon the distribution of a firm's productive units, its marginal costs relative to those of its rivals, forecast demand, and factors unobservable to the econometrician. There are a number of ways to describe these differences across firms. In the specification reported here, the underlying (latent) profitability for generator (firm) f being the price-setter on day t is assumed to follow

$$\begin{aligned} \mathrm{PS}_{ft}^{*} = {} & \alpha_0 + \alpha_1 \mathrm{TKB}_{ft} + \sum_{n=1}^{2} \alpha_{cn} \overline{\Delta c_{n,ft}} + \sum_{n=1}^{2} \gamma_{cn} \overline{\Delta c_{n,ft} \mathrm{MK}_{ft}} + \alpha_2 \mathrm{MK}_{ft} \\ & + \Sigma_m \alpha_{3m} \mathrm{FT}_{m,ft} + v_{ft}. \end{aligned} \tag{2}$$

where TKB_{ft} measures firm f's total production capacity below the intersection of the daily peak demand with the aggregate marginal cost schedule, MK_{ft} measures a firm's production capacity within 3000 MW of this intersection, $\overline{\Delta c_{n,ft}}$, $n=1,2$, measure the average weighted (by capacity) difference in marginal costs of production between a firm's own and its rivals' first and second units, respectively, near the peak, $\overline{\Delta c_{n,ft} \mathrm{MK}_{ft}}$ measures the marginal cost differences interacted with a firm's marginal capacity, and $\mathrm{FT}_{m,ft}$ are fuel-type dummies.[32]

The motivation for including each of these variables follows closely the discussion of the elements impacting the decision to price out units described by Eq. (1). In particular, a firm with greater productive capacity below peak demand benefits more from a high price and thus has greater incentive to be the price-setter. Similarly, a firm with capacity near the margin has higher marginal costs relative to a firm with baseline capacity; the lost revenue on pricing out its marginal units is therefore lower, increasing its incentive to be the price-setter. As described in Section 3.4, the difference in marginal costs of production for a unit at the margin between a firm and its rivals impacts the extent to which pricing out units raises the market price. Of course, this only matters to the extent a firm has sufficient capacity at the margin to affect the price. Thus, increases in the size of potential price increases, by themselves and interacted with a firm's capacity at the margin, increase the incentive to be the price-setter. Finally, we include fuel-type dummies to reflect any unmeasured costs of taking units in and out of production. The fuel types may also proxy for whether units are infra-marginal, marginal, or extra-marginal.[33] Under the assumption that a firm's and its rivals' generating portfolios are exogenously given, all of the parameters of the price-setter equation are identified.[34]

Table 2 reports summary statistics for the variables appearing in the price-setter equation. In constructing the binary for whether or not a firm is the price-setter on a particular day, we face the complication of having 48 demand periods and 48 prices each day but only one bid function. Since the implications of the BFE theory are sharpest for the peak periods, we define the price-

[32] Throughout the paper, we examine bidding behavior within 3000 MW of peak demand. This is intended to capture behavior "near the margin". While necessarily arbitrary, our qualitative conclusions are robust to variations in this choice.

[33] The fuel types are coal, auxiliary gas turbine, oil, combined coal and oil, combined cycle gas turbine, gas turbine together with combined oil and gas turbines, nuclear, pumped storage, hydro, and waste heat generation. In estimation, coal and auxiliary gas turbine, were combined since the turbine generators are installed in coal plants as backup and peaking units. The last two categories were also combined.

[34] While a strong assumption, generating portfolios are clearly fixed in the short run. Furthermore, as discussed in Section 5.2.2, changes in generating portfolios appear to be driven by technical and not strategic motivations.

Table 2
Summary statistics: price-setter equation

Variable	Mean	Standard deviation
Total capacity below peak (MW)	2215.4	4215.3
Marginal capacity at peak (MW)	593.3	1519.0
Fraction of a producer's capacity		
Coal or AGT used in coal plants	.16	.30
Nuclear	.08	.22
Combined cycle gas turbine	.58	.48
Oil	.01	.04
Coal/oil	.01	.03
Pumped storage	.06	.24
Gas/combined oil gas turbine	.06	.22
Other fuel type	.05	.15
$\overline{\Delta c_1}$ for Producers with Marginal Units	.41	1.29
$\overline{\Delta c_2}$ for Producers with Marginal Units	7.92	49.53

Notes: Sample is 14,813 firm days. Total Capacity Below Peak is the firm's total capacity in Megawatts (MW) below the intersection of peak demand in a given day and the aggregated marginal cost schedule of all firms in that day. Marginal Capacity at Peak is a firm's capacity within 3000 MW. $\overline{\Delta c_j}$ for $j=1$, 2 is the average capacity-weighted difference in marginal costs between a firm's own and its rivals' jth unit near the intersection of peak demand and aggregate marginal cost. Other fuel type includes Waste Heat Generation, Hydro, and Unknown fuel types.

setting dummy variable for firm f on day $t(\mathrm{PS}_{ft})$ to have the value 1 when firm f is the price-setter at least as many times as any other firm during the highest ten demand periods of the day. While this definition allows for the possibility of multiple price-setters in a day, few occurrences are found in the data.

We assume $\mathrm{PS}_{ft}=1$ if $\mathrm{PS}^*_{ft}\geq 0$, and $\mathrm{PS}_{ft}=0$ otherwise. We further assume that the error term, v_{ft}, is distributed normally and present the parameters estimates for the resulting probit model in

Table 3
Parameter estimates: price-setter equation

Variable	Coefficient	Standard error
Constant	−0.322	0.032
Total capacity below peak (10,000 MW)	1.149	0.115
Marginal capacity at peak (10,000 MW)	0.822	0.217
% of producer's capacity		
Coal or AGT used in coal plants	−2.099	0.191
Combined cycle gas turbine	−2.614	0.165
Oil	−1.997	0.997
Coal/oil	−1.074	0.921
Gas/combined oil-gas turbine	−1.686	0.036
Unknown fuel type	−1.074	0.921
$\overline{\Delta c_1}$	−2.190	7.620
$\overline{\Delta c_2}$	0.457	0.167
$\overline{\Delta c_1^*}$ Marginal capacity	0.518	0.202
$\overline{\Delta c_2^*}$ Marginal capacity	−0.005	0.004
Psuedo R-squared = .45		

Notes: Sample is 12,769 firm days. Reported are results from a probit specification. The dependent variable is PS_{ft}, a dummy variable indicating whether firm f set the price at least as many times as any other firm in the 10 highest demand periods in day t. Producers with only nuclear, hydro, and waste heat plants are never price-setters and are omitted. Omitted fuel type is Pumped Storage. Robust standard errors are reported.

Table 3. The pseudo R-squared for the price-setter equation is .45, suggesting that predictions of price-setting behavior are reasonably good. As might be expected, the strongest impact on price-setting comes from features of firms' distribution of generating capacity, namely firms with greater capacity below peak demand and with more capacity near the margin are significantly more likely to be the price-setters. Since marginal capacity enters the latent price-setter equation in both a linear and interacted form, the total effect depends upon the cost differences. At the means for these differences, a 1% increase in capacity below the peak (marginal capacity) leads to a .61% (.12) increase in the probability of being the price-setter. The effects of cost differences, while statistically significant, are economically small and the fuel type dummies are consistent with industry expectations.

In addition to the specification presented here, we estimated a number of other specifications of the price-setter equation using alternative measures of the distribution of the productive

Table 4
Summary statistics bid markup equation

Variable	All units		Price-setters		Non-price-setters	
	Mean	Standard deviation	Mean	Standard deviation	Mean	Standard deviation
All units						
ACB	8,636	6,971	12,191	6,758	7,242	6,546
ln ACB	8.36	1.60	9.10	0.99	8.06	1.69
Δc_1	9.15	74.26	5.49	54.53	10.58	80.64
ln Δc_1	0.60	0.94	0.52	0.82	0.62	0.99
Δc_2	19.41	107.68	15.61	94.23	20.90	112.49
ln Δc_2	1.06	1.19	0.99	1.12	1.08	1.22
INF	0.47	0.50	0.36	0.48	0.52	0.50
BI	0.13	0.34	0.14	0.35	0.13	0.34
PS	0.28	0.45	–	–	–	–
NPS	0.72	0.45	–	–	–	–
I3	0.10	0.30	0.11	0.31	0.09	0.29
Observations	141,164		39,771		101,393	
Units near peak demand (I3 = 1)						
ACB	8822	5673	10,946	5278	7840	5580
ln ACB	8.60	1.30	9.07	0.86	8.38	1.41
Δc_1	0.28	0.62	0.28	0.47	0.28	0.68
ln Δc_1	0.20	0.27	0.21	0.25	0.20	0.28
Δc_2	10.29	76.85	8.92	67.77	10.93	80.70
ln Δc_2	0.73	0.94	0.74	0.90	0.73	0.95
INF	0.00	0.00	0.00	0.00	0.00	0.00
BI	0.21	0.41	0.24	0.43	0.20	0.40
PS	0.32	0.46	–	–	–	–
NPS	0.68	0.46	–	–	–	–
Observations	13,810		4366		9444	

Notes: Total sample is 141,164 unit days. Means in the price-setter (non-price-setter) column are for all units owned by the firm(s) that set (did not set) the price at least as many times as any other firm in the 10 highest demand periods in a given day. ACB is Available Capacity Below, the total capacity owned by the same firm that has lower marginal cost than the given generating unit. Δc_j for $j=1$, 2 is the difference in the marginal costs of the generating units appearing $j+1$ and j places ahead in the rival firms' aggregate marginal cost curve. BI measures Bid Impact, a dummy variable equal to 1 if the rival's unit with closest marginal cost is unavailable in a given day. PS (NPS) is a dummy equal to 1 if the unit is owned by the firm that is the (non-)price-setter. I3 is a dummy equal to 1 if the unit is within 3000 MW of the intersection of aggregate marginal cost and peak demand. INF is a dummy equal to 1 if a unit is infra-marginal and not within 3000 MW this intersection.

capacity and marginal costs, other fuel type categories (e.g., auxiliary gas turbine as a separate fuel group), and firm effects for the most common price-setters. The qualitative conclusions described above were unchanged.

5.2. Bid markup equation

As described in Section 3.4, BFE predict differences in bidding behavior between price-setters and non-price setters. These predictions are strongest in peak demand periods, but are also in effect in non-peak periods. To assess the implications of the theory for each of these possibilities, we estimate three specifications of the bid mark-up equation. In our baseline empirical model (Model A), we follow previous empirical specifications in the same market (Wolfram, 1999) to verify our findings duplicate those found in the literature. Our second specification (Model B) allows for asymmetries in bidding behavior for the PS and the NPSs throughout their bid functions. Our final specification (Model C) also allows for variation in strategies for units that are near the margin during periods of peak demand versus units that are infra- or extra-marginal during these periods.

5.2.1. Specification of the markup equation

Specification A ignores the asymmetries between the PS and NPS and the differences in bidding on marginal and non-marginal units. This baseline model for generating unit i in half-hour period t is

$$\ln m_{it} = \beta_0 + \beta_1 \ln \mathrm{ACB}_{it} + \sum_{n=1}^{2} \beta_{2n} \ln \Delta c_{nit} + \beta_3 \mathrm{INF}_{it} + X_{it}' \gamma + u_i + \epsilon_{it} \quad (3)$$

with each of the included variables defined below. Table 4 lists the descriptive statistics for the explanatory variables used in this and the remaining specifications.

The dependent variable is the natural logarithm of the bid markup (m_{it}), defined as the bid price submitted for generating unit i minus its marginal (fuel) cost. Available Capacity Below (ACB_{it}) is the amount of capacity that is owned by the same generator as owns unit i and that has lower marginal cost than unit i.

The cost difference variables (Δc_{nit}) are based on the aggregate marginal cost curve for the rivals to the firm owning unit i. The difference Δc_{nit} is the marginal cost of the generating unit that appears $n+1$ places ahead of the marginal cost for unit i minus the marginal cost for the unit that appears n places ahead in the rival firms' aggregate marginal cost curve.[35] The binary INF_{it} is one if unit i is infra-marginal and *not* within 3000 MW of the intersection and zero otherwise. Additional independent variables (X_{it}) capture heterogeneity in cost and demand conditions over generating units and time. The vector X_{it} includes time dummies for the days of the week and the months of the year. Following Wolfram (1999), it also includes a Bid Impact dummy equaling one if the rival's unit with the closest marginal cost is unavailable at t and zero otherwise. The u_i are generating unit fixed effects. Finally, we include a random disturbance, ϵ_{it}, that is assumed to be orthogonal to all other variables. We discuss this assumption in detail in the next subsection.

[35] We add one to the difference since in many cases competitors have adjacent units with equal marginal costs.

Specification B admits the possibility of different bidding strategies for the PS and NPS. For each of the variables of primary interest, we include an interaction term for whether the firm owning the unit is a price-setter during the peak demand periods of day t,

$$\ln m_{it} = D'_{it}\overrightarrow{\beta}_0 + \ln(\mathrm{ACB}_{it})D'_{it}\overrightarrow{\beta}_1 + \sum_n \ln(\Delta c_{nit})D'_{it}\overrightarrow{\beta}_{2n} + \mathrm{INF}_{it}D'_{it}\overrightarrow{\beta}_3 + X'_{it}\gamma + u_i + \epsilon_{it} \tag{4}$$

where $D_{it} \equiv (1, \mathrm{PS}_{it})$ is the 1×2 row vector consisting of a constant and a dummy variable for whether unit i belongs to a firm that is a PS during the peak demand periods of day t, and $\overrightarrow{\beta}_s \equiv (\beta_s, \beta_s^{\mathrm{PS}})'$ for $s \in \{0, 1, 2, 3\}$ is a corresponding 2×1 parameter vector. In this setting, β_s^{PS} for $s = 0, \ldots, 3$ are interpreted as the incremental effects of being a price-setter on each of the included variables in the baseline model.

Finally, Specification C allows for differences in the bidding on marginal and non-marginal units. The final specification is

$$\begin{aligned}\ln m_{it} = {} & D'_{it}\overrightarrow{\beta}_0 + \ln(\mathrm{ACB}_{it})D'_{it}\overrightarrow{\beta}_1 + \sum_n \ln(\Delta c_{nit})D'_{it}\overrightarrow{\beta}_{2n} + \mathrm{INF}_{it}D'_{it}\overrightarrow{\beta}_3 + I3_{it}D'_{it}\overrightarrow{\beta}_0^{\mathrm{Peak}} \\ & + I3_{it}\ln(\mathrm{ACB}_{it})D'_{it}\overrightarrow{\beta}_1^{\mathrm{Peak}} + \sum_n I3l_{it}\ln(\Delta c_{nit})D'_{it}\overrightarrow{\beta}_{2n}^{\mathrm{Peak}} + X'_{it}\gamma_1 + u_i + \epsilon_{it}.\end{aligned} \tag{5}$$

The two new variables, $\mathrm{I3}_{it}$, and $\mathrm{I3l}_{it}$, measure the position of unit i relative to the intersection of the aggregate marginal cost curve and the peak demand for day t. The binary $\mathrm{I3}_{it}$ is one if unit i is within 3000 MW of the intersection of aggregate marginal cost function and the peak load of day t and zero otherwise.[36] The dummy variable $\mathrm{I3l}_{it}$ measures the infra-marginal component (i.e. left half) of I3, which is the appropriate segment to interact with the cost change variables in testing Implication 2. The $\overrightarrow{\beta}^{\mathrm{Peak}}$ coefficients measure the incremental effect on bid markups of being near the margin in peak demand periods on each of the included variables in Specification B.

5.2.2. Identification

Identification of the coefficients for the bid markup equations rests on the assumption that ϵ_{it} is orthogonal to the included regressors. There are two primary identification issues: the possibility endogeneity of PS_{it}, the identity of the firm owning unit i and setting prices in the peak demand period(s) in the day including half-hour t, and ACB_{it}, the available capacity owned by the firm owning unit i and below it in marginal cost order. We address each in turn.

It is clear that firm's bidding decisions are closely related to the identity of the price-setter. As suggested by the price-setter equation, we address this endogeneity by estimating a separate Probit equation predicting the identity of the price-setter based on exogenous features of firm's generation portfolios.[37] This raises the question of the variation in the data that identifies the price-setter separately from bid markups themselves. While based on the same underlying principles (the profitability of being the price-setter), separate identification of the parameters in the bid markup

[36] Note that the designation of units as infra-marginal or near-marginal is based on the intersection of the aggregate marginal cost curve and the peak daily demand Following this approach avoids the endogeneity inherent in a definition based on the intersection of the aggregate bid curve and the peak demand.

[37] We also estimated the bid markup equation using instrumental variables with instruments given by the same features of firm's generation portfolios that enter the price-setting equation. These yielded qualitatively similar results. We report the two-stage approach due to our interest in the determinants of the price-setter's identity.

and price-setter equations rests on the difference in the level of aggregation for the two equations. In particular, the independent variables for the bid-markup equation measure characteristics of the individual generating unit, whereas the independent variables for the price-setter equation focus on characteristics of each firm's entire generating portfolio. These are unlikely to be correlated with the error associated with a particular unit and time period, particularly in the presence of unit fixed effects.

Within the bid markup equation itself, there is some concern that Available Capacity Below (ACB_{it}) is also endogenous.[38] In particular, since generators decide simultaneously on their bids and the availability of their units, this could induce correlation between ACB and the error term. Including fixed effects, however, specifically addresses this issue. Any persistent relationship between bidding and availability for a given unit is captured in the unit fixed effect. Identification of the coefficient on ACB therefore arises from its variation *over time* for a given unit. Such variation might occur for two primary reasons. First, generating units require regular maintenance and repair, a process which is plausibly exogenous to the firm's bidding decisions. As this happens, however, the ACB for a given unit will vary and so too the incentives to price out that unit. Second, new units are entering and being retired in this period. We maintain the assumption that these decisions are exogenous to the bidding behavior of firms. While strong, there is justification for it in the literature. In its survey of plant disconnections and decommissioning, the NGC (1999) found no evidence of strategic manipulation. Furthermore, Rainbow et al. (1993) cite numerous non-strategic factors for closing coal plants during this period (the vast majority of plant closures in our sample are coal plants). Finally, entry has been exclusively through the construction of CCGT plants whose operating characteristics (and consequent impact on bid functions) are largely outside the control of each firm.

Finally, note that basing the analysis on the *entire bid function* of each firm reduces concerns about mis-measurement in the analysis. For instance, included in ϵ_{it} are elements assumed to be observed by firms but not the econometrician. These include shocks to bidding behavior (e.g. bidding heterogeneity), shocks to cost (e.g. fuel price variation), and shocks to expectations of other firms' availability (e.g. rival units' maintenance and repair). While unobserved demand shocks are not relevant to the firms' bidding (as SMP is set by the intersection of the day-ahead aggregate bid function and the day-ahead demand estimate), shocks to rivals' capacity availability has the effect of shifting a firm's residual demand curve. This would be a problem if we were looking only at the *marginal* unit (as in conventional supply and demand analysis), where shocks could introduce correlation between the *observed* ACB and ϵ. Along the entire bid function, however, ACB is fixed (excepting maintenance and entry described above) and cannot respond to shocks in ϵ.[39]

5.2.3. Estimation of the bid markup equation

In estimating the bid markup equations, we use the predicted probability that the generator owning unit i is a price-setter in place of the dichotomous variable PS_{it}. To correct for any bias

[38] The remaining regressors, unit capacity and the change in competitors' costs are plausibly exogenous to the firm.

[39] Nonetheless, it is possible that cost shocks could induce a bias in the ACB coefficient. To the extent these represent unobserved changes in fuel prices, they are likely to be correlated across units for a given time period but uncorrelated over time. To allow for this possibility, we also estimated the markup equation using levels of ACB_{is} for $s \neq t$ to instrument for ACB_{it}. The choice of s was made to maximize the correlation between the two measures of capacity while allowing for enough time for persistence in the cost shock to not be a problem. These results did not differ appreciably from those presented here.

Table 5
Parameter estimates bid markup equation

Symbol	Specifications / Variable	Baseline (A) Coefficient	Baseline (A) Standard error	PS effects (B) Coefficient	PS effects (B) Standard error	PS and peak (C) Coefficient	PS and peak (C) Standard error
All generating units in all demand periods							
β_0	All firms	−0.843	0.041	0.443	0.054	0.573	0.055
	PS			−5.760	1.402	−6.625	1.623
β_1	ln ACB	0.338	0.005	0.178	0.038	0.168	0.041
	ln $\mathrm{ACB}^{\mathrm{PS}}$			0.679	0.143	0.746	0.163
β_{21}	ln Δc_1	−0.086	0.004	−0.081	0.036	−0.134	0.040
	ln Δc_1^{PS}			−0.003	0.153	0.130	0.156
β_{22}	ln Δc_2	0.015	0.002	−0.009	0.005	−0.004	0.013
	ln Δc_2^{PS}			0.083	0.014	0.048	0.034
β_3	INF	0.011	0.008	−0.197	0.087	−0.316	0.101
	$\mathrm{INF}^{\mathrm{PS}}$			0.589	0.208	0.936	0.254
γ	BI	0.110	0.007	0.102	0.063	0.108	0.069
	$\mathrm{BI}^{\mathrm{PS}}$			0.041	0.197	0.020	0.207
Marginal generating units in peak demand periods							
$\beta_0^{\mathrm{Peak,Marg}}$	All firms					−0.946	0.321
	PS					3.954	1.090
$\beta_1^{\mathrm{Peak,Marg}}$	ln ACB					0.094	0.038
	ln $\mathrm{ACB}^{\mathrm{PS}}$					−0.380	0.122
$\beta_{21}^{\mathrm{Peak,Marg}}$	ln Δc_1					0.205	0.045
	ln Δc_1^{PS}					−0.074	0.365
$\beta_{22}^{\mathrm{Peak,Marg}}$	ln Δc_2					−0.016	0.014
	ln Δc_2^{PS}					0.039	0.038
R^2 within			0.06		0.10		0.10
σ_u			2.00		1.88		1.88
σ_e			0.80		0.79		0.79
F-statistic			439.61		1137.29		896.97

Notes: Sample is 141,164 unit days. Estimation is by Ordinary Least Squares using the predicted probability each firm is the price-setter (from the Table 3 results) in place of the identity of the price-setter. Standard errors are bootstrap standard errors. All specifications include fixed effects for generating units. Baseline Specification (A) ignores asymmetries between the price-setter (PS) and non-price-setters (NPSs) and differences in bid functions for marginal and non-marginal units. PS Effects Specification (B) allows for asymmetries between the PS and NPSs. PS & Peak Specification (C) allows asymmetries and differences between marginal and non-marginal bid functions.

generated by using the predicted variables as regressors we use a bootstrap method to estimate the standard errors in Specifications B and C of the markup equations.[40]

5.2.4. Bid markup results

The first column of Table 5 presents the parameter estimates for our baseline specification designed to mimic the specification tested by Wolfram (1998) with comparable data. Our results are quite similar. As there, bid markups increase with infra-marginal capacity and bid impact, with mixed results for the cost change variables.

[40] We estimate the price-setter and bid markup equations for 1000 bootstrap samples and use the standard deviation for each of the estimated coefficients in the bid markup equation as its standard error. The number of observations in each of the bootstrap samples equals the number of observations in the bid markup data set. Each of the 1000 bootstrap data sets was created by sampling with replacement from the unit-level data set used in estimating the bid markup equation. The data set needed for estimating the price-setter equation for each of the bootstrap samples is at the firm rather than the unit level and is defined directly from each of the corresponding unit-level bootstrap sample.

The next column of Table 5 generalizes the specification to allow for separate impacts for the PS and NPS. This clearly shows the differences in the bidding behaviors of price-setting and non-price-setting firms. While all generators bid larger markups the greater their infra-marginal capacities ($\hat{\beta}_1 = 0.178$), the effect for a PS is almost five times that for a NPS ($\hat{\beta}_1 + \hat{\beta}_1^{PS} = 0.857$). Also note that the coefficient on the PS dummy is negative and statistically significant. The positive coefficient on the PS infra-marginal capacity together with the negative coefficient on the PS dummy support the BFE hypothesis that the PS's bid function has a lower intercept and steeper slope than the NPS'.[41]

The balance of the discussion regarding the implications of BFE focuses on the units that are near the margin during periods of peak demand where bid functions are unaffected by strategic considerations in other periods. The third column of Table 5 lists the estimated coefficients allowing for differences in the bid markups for PS and NPS on units that are marginal during the peak periods of the day. We preview our results by noting that most of the implications of BFE outlined in Section 3.4 are supported by the estimates.

Consider first the level of bid markups. Given the interaction terms, we examined the differences in the markups between the PS and NPS by computing the derivative of the estimated markup with respect to the PS variable. We find that bid markups are significantly higher for the PS than for NPS. At the mean of the explanatory variables, mean log markups *for a given unit* in non-peak periods are estimated to be 0.51 higher for the PS than NPS, and an additional 0.40 higher in peak demand periods.[42] Note this is a *very large* difference, more than half the average log bid markup in the sample as a whole (0.96)!

With respect to strategic incentives, the additional effect of an extra unit of infra-marginal capacity is now nearly 5.5 times greater for a PS than for a NPS (0.168 versus .914). Indeed, this is a very large difference. A 10% increase in the available capacity below a given unit, for example due to maintenance or repair of baseload generation, increases predicted markups by 9.1% for a price-setter, but only 1.7% for a non-price-setter. The results for cost differences are mixed. Cost differences with rivals' units have similar impacts on the bids of both PSs and NPSs, with statistically insignificant (though larger) effects for PSs.[43]

The final implication, that of bid lumping for the price-setter, is also supported by this specification. In the peak periods, the price-setter's bid markups are both higher (by the 0.40 reported above) and flatten (the PS $\beta_1^{\text{Peak,Marg}} < 0$) relative to non-peak periods. By contrast, the slope of the bid function for units owned by NPSs actually increases in peak periods.

6. Using BFE to simulate market prices

Given the support for BFE in the estimation, we next applied BFE to simulate equilibrium clearing prices in periods of peak demand for the England and Wales market both for baseline market conditions and under counterfactual scenarios designed to examine alternatives to mitigate market power in deregulated electricity markets. Note that this exercise is meant to be illustrative: there are important differences between the economic environment assumed in BFE and that in

[41] The estimates imply that the incremental effect of being a PS on markups is positive for all but the lowest generating units in marginal cost order.

[42] In addition, log markups for a given unit are higher for the PS in peak relative to off-peak demand periods (difference of 0.41) and also higher for the NPS (difference of 0.51).

[43] Furthermore, the magnitude of rivals' cost effects on PS bids are consistent with the BFE theory across and within periods (i.e. they are larger in peak versus off-peak periods and are larger for adjacent versus distant units).

the England and Wales market that would need to be resolved prior to its use in a policy-making setting.[44]

6.1. Overview

Consider first the case of simulating baseline market conditions. As suggested by the theoretical model, the simulations were conducted in several steps. First, for each day, t, we set the price-setter to PS_{ft}, the firm that set the price at least as many times as any other in the ten highest demand periods on that day. Using the peak demand value for each day and the marginal cost of each unit *not* belonging to the price-setter, we next constructed a residual demand curve for the PS associated with each day. Finally, we used the PS's residual demand curve and the PS's own marginal cost curve to form its profit function and chose the profit-maximizing price for the day.[45] When simulating counterfactual scenarios, we first predicted the price-setter for each day using our model estimates in Section 5 and then proceeded as in the baseline case.

6.2. BFE simulations and corner solutions

In our initial simulations, there was a very high frequency of "corner solutions" when National Power was the price-setter. That is, when the total capacity of all firms excluding National Power was not sufficient to supply the full peak demand, National Power faced an extremely inelastic residual demand curve. As a result, it could bid as high as the price cap of 2000 British pounds and still be assured that some number of units would run. The same was often true when PowerGen was the price-setter.

The situation in which it is not possible for all but one firm to supply the peak demand runs contrary to a maintained assumption of BFE (cf. Footnote 7). Furthermore, in practice, the prices in the England and Wales market did not reach the price cap during the same days that the price cap was reached in the simulations. This discrepancy is not severe, however, and merely reflects the simplifications inherent in the modeling of a complex operational and institutional structure like wholesale electricity markets. For example, corner solutions are profitable only when the price-setter prices out a *very* large amount of generation capacity (e.g. 5000–7000 MWH, or roughly 5–7 large coal plants). While not explicitly incorporated into BFE, there are likely to be significant costs of such actions. First, baseline units (like coal and nuclear plants) are designed to run for long periods of time. As such, there are important constraints and costs associated with bringing them online and offline. These costs are not captured in the standard BFE. Furthermore, there would surely be significant regulatory and political consequences of setting such a high price. For example, regulatory intervention in the England and Wales market has included an agreement between National Power and PowerGen and the UK Monopoly and Mergers Commission to keep a weighted-average of prices below a certain level in order to avoid a monopolization investigation, forced divestiture, and a windfall tax imposed on generators for receiving high profits.

To more accurately simulate the actual EW market, we therefore modified our simulations to incorporate some of these costs. In particular, we restricted the amount of capacity that could be

[44] In particular, the issues of contract cover and pricing with multiple demand periods discussed in Section 3.3 would have to be resolved.

[45] Wolak (2000), Sweeting (2005), and Hortacsu and Puller (2006) use a similar approach based on all firms *bids* to test whether observed generator behavior is consistent with short-run profit maximization.

priced out by the PS to 5000 MW. Because generators were forced to divest generation in 1994, the total amount of capacity owned by the two price-setters declined significantly during the sample period. For this reason, 5000 MW represented a good balance between allowing a (more than) reasonable amount of capacity to be priced out, while still providing interior solutions for the entire sample.[46] This restriction was chosen for analytical convenience; alternative specifications incorporating the costs associated with pricing out large numbers of units would have similar effects.

6.3. Results

Simulations under the 5000 MW restriction yielded an average markup in periods of peak demand of 22.5% for the price-setting unit. This is quite close to what we find in our data as well as those estimated by Wolfram (1998) of between 20% and 27%. Furthermore, we find that when the two largest firms, National Power and PowerGen, were price-setters, the simulated markup was about 30% for the price-setting unit. By contrast, small generators usually did not find it advantageous to act strategically in the simulations and when they did (about 1% of the peak hours), their predicted markups were much smaller. Each of these features also holds in the data. Thus, BFE appear quite accurate in explaining equilibrium prices in the EW market during the time period we examine.

We next considered simulations designed to evaluate alternatives for mitigating market power in deregulated electricity markets. In both the USA and other countries with deregulated electricity markets, the potential for firms to exercise market power has been the source of great preoccupation by regulators. In the United States, for example, the FERC's Standard Market Design calls for a number of measures to prevent abuses of market power. These include careful monitoring of bidding behavior and restrictions on bidding for generation units that are key to realizing market power. The FERC also screens generators for potential market power before granting them market-based rates. Furthermore, in both the USA and in England and Wales, regulators have required generators to divest at least a portion of their generation assets due to market power concerns.

Whatever the proposed method of mitigation, BFE can be used to simulate the outcomes of and compare mitigation alternatives. We used BFE to estimate the competitive effects of divesting 5000 MW of generation owned by National Power. In particular, we compared divestiture of base load generation to divestiture of intermediate load generation and examined the effects of these two alternatives under high peak demand (the 90th percentile) and low peak demand (the 10th percentile). Our results show that divesture of 5000 MW did little to affect bidding behavior during very high demand periods. During these periods, National Power would still have owned over 15,000 MW of available capacity and BFE still predict corner solutions except when restrictions are placed on the amount of capacity that can be priced out. During lower demand periods, however, BFE simulations predict that divestiture of both base-load and intermediate-load units would have an effect on bidding behavior. In particular, divestiture of base load reduced simulated prices by 7.6% and divesture of intermediate load reduced simulated prices by 16.8%. This difference in results highlights the importance of the location of divested

[46] In other words, the specific level of our chosen cap (below 7000 MW) was unimportant; in all cases the cap did not bind. Another way of describing this is that the profit function without a cap was double-humped: it was concave to approximately 5–7000 MW and then spiked as the residual demand became perfectly inelastic. The 5000 MW cap simply removes from consideration the possibility of the spike.

capacity in marginal cost order for the consequences of divestiture: when intermediate load generation is divested there is less infra-marginal capacity and the foregone markup from pricing out units is higher. When base load is divested, there is less infra-marginal capacity over which markups can accrue, but the forgone revenues from pricing out intermediate units remains little changed.[47]

7. Implications, conclusion and extensions

The purpose of this paper is to provide an explanation of firm behavior in wholesale electricity markets. We do this by testing the implications of Bid Function Equilibria in the England and Wales spot market for electricity. The primary implication of BFE is the presence of *asymmetries* in bidding behavior between the firm that sets the clearing price (the price-setter) and all other firms (non-price-setters). Using data on bid functions between 1993 and 1995, we find strong empirical support for the theory. Strong and persistent asymmetries exist in bid functions consistent with strategic bidding by price-setters in a Bid Function Equilibrium.

BFE have several important implications regarding the efficient regulation of wholesale electricity markets. First, it offers important insights into the tradeoff between short- and long-run efficiency in these markets. In a seminal paper, Christensen and Greene (1976) found that "technological change unrelated to increases in scale deserves the primary attribution for… declines in the cost of [electricity] production." This discovery was used to promote competition in generation and ultimately the deregulation of electricity markets the world over. Today, there is a great deal of energy devoted to mitigating short-run market power, independent of the industry's long-run objectives. While our estimates of markups (on the order of 22–23%) are significant, they are less than the 30% or more by which average costs of generation exceed marginal costs. Given that fixed cost recovery is essential to promoting new efficient technologies, BFE support the conclusion that, *under normal market conditions*, markups are likely to be in a range that promotes fixed cost recovery without necessarily leading to above-normal profits. That being said, the frequency of corner solutions in the simulations, although less likely in today's less concentrated markets, highlights the importance of mitigating market power when one ("pivotal") supplier has an incentive to exploit capacity constraints.[48] Finally, if divestiture is being considered as a way to address market power, BFE indicate that *targeting* specific generating units (e.g. intermediate versus baseload capacity) can significantly enhance market performance.

There are many possible extensions of this research. The most immediate application would be for use in other wholesale electricity markets. For example, in recent years there has been an emergence of a literature examining market power issues in the newer California deregulated market for electricity (Borenstein and Bushnell, 1999; Borenstein et al., 2002; Wolak, 2000). Similar issues have arisen in the New England (NEISO), New York ISO (NYISO) and the

[47] Certain caveats to these conclusions apply. We do not, for example, consider the effect that the various generation technologies have on the opportunity costs of pricing in or pricing out units, nor do we discuss simulations over a complete set of supply/demand scenarios. These and other mitigation alternatives may, however, be easily accommodated.

[48] Indeed, this suggests strategic availability decisions would differ qualitatively from strategic bidding behavior predicted by BFE. In particular, all firms might well want to reduce capacity availability in an effort to make a single supplier pivotal. See Wolak and Patrick (2001), Joskow and Kahn (2002), Lave and Perekhodstev (2001), and Perekhodstev et al. (2002) for more on pivotal suppliers.

Pennsylvania, New Jersey, and Maryland (PJM) markets (e.g. Mansur, 2005). Although BFE would have to be generalized to include idiosyncratic aspects of these markets, its basic features would remain. Even more promising is to address issues of market power during periods of high demand by incorporating Bid Function Equilibria in a structural model of short-run strategic availability decisions by generators. Similarly, the wealth of data and repeat nature of play in electricity markets provide ample opportunity to study explicit or tacit collusion in the market (e.g. Puller, in press; Sweeting, 2005). BFE would assist these efforts by characterizing outcomes in downstream stages (i.e. conditional on availability or as the punishment stage in a repeated game), enabling the analysis to focus on such higher-order strategic incentives.

Appendix A. A theoretical details

This section presents the basic Bid Function Equilibrium model and provides proofs for its core components. The interested reader is referred to Crespo (2001) for further details.

A.1. Construction of the basic model

The game, $\Gamma_1=\langle(1,2),\beta,U,(\pi_i),M\rangle$ represents a duopoly where the players are denoted by i, $j\in(1,2)$. The auction demand, M, is a positive integer which we assume to be even. Each firm has M production units with the size of the units normalized to be one.[49] In this basic model, the cost functions of firms are symmetric. The cost of producing q units is $C(q)$ and $c(q)$ is the marginal cost of producing the qth unit. Each firm is required to submit separate prices for each of the M units. Strategies are expressed as bid functions σ_i: $U\rightarrow\beta$, where $\sigma_i(q)$ is the price at which firm i is willing to supply its qth unit. Hence, the domain of σ_i is $U=\{1,2,\ldots,M\}$ and its range is the continuous interval, $\beta=[0,\bar{P}]$, where $\bar{P}$ is an arbitrary price ceiling.[50]

Once bid functions are submitted, a scoring mechanism determines the number of units each firm sells into the market according to the M lowest bid prices in the aggregate of the pair $(\sigma_1,\sigma_2)\equiv\sigma$. These quantities are denoted (q_1,q_2). The compensation for each unit sold is the uniform clearing price, $P\in\beta$, equal to the highest accepted bid. An outcome is therefore $O(\sigma)=\{q_1,q_2,P\}$,[51] $q_1+q_2=M$, and $P=\max_{i\in(1,2)}\{\sigma_i(q_i)\}$. Profit is denoted $\pi_i(\sigma_j,\sigma_i)=Pq_i-C_i(q_i)$. When there is a tie in the bid prices for the last unit needed to accommodate demand, then it is assumed that the lower-cost unit is taken.[52]

We next define the price setter and marginal unit.

Definition 1. Firm i is a Price Setter for the outcome $O(\sigma)=(q_i,q_j,P)$, if $\sigma_i(q_i)=P$.

Definition 2. If firm i is a price setter given the outcome $O(\sigma)=(q_i,q_j,P)$, then firm i's marginal unit is q_i and firm j's marginal unit is q_j.

[49] The theory extends easily to units of differing sizes, but complicates the math. For this reason, we present the theory with unit size normalized to one.

[50] For example, if $M=3$ and $\bar{P}=1$, then σ_i might be given by (0, 0.1, 0.4), i.e. the bid price for firm i's three units are $\sigma_i(1)=0$, $\sigma_i(2)=0.1$, and $\sigma_i(3)=0.4$.

[51] In most of the auction literature, outcomes are often expressed in revenues rather than prices. However, the latter alternative will conserve on notation and simplify forthcoming analysis.

[52] This assumption is made of expositional convenience. It was chosen because it provides outcome-equivalent equilibria to a model with a discrete bid space and a rationing rule for when ties occur.

The assumptions that are used in the basic model are straightforward.

- A1: The auction demand, M is known ex-ante.
- A2: There is complete information regarding the other firm's payoff function.

The solution concept used in this basic model is Nash equilibrium.

Definition 3. A Nash equilibrium of multi-unit auction with complete information is any pair of strategies σ such that: $\pi_i(\sigma_j,\sigma_i) \geq \pi_i(\sigma_j,\tilde{\sigma}_i)$, for all $i \in (1,2)$ where σ_i, σ_j and $\tilde{\sigma}_i$ are mappings from U into β.

A.2. Bidding behavior by each firm

Crespo (2001, p.7) shows that it is never optimal for firms to play weakly dominated strategies. These include bidding units out of marginal cost order (i.e. setting bids for high-cost units below those of low-cost units) or bidding units below marginal cost. The remainder of this appendix restricts our attention to strategies that are not weakly dominated.

A.2.1. Bidding behavior by the non-price setter

Crespo (2001) characterizes equilibria in two steps. First, it shows that if firm i is the price-setter, it is optimal for firm j to bid each unit at its marginal cost or at bids that yield outcomes equivalent to bidding each unit at its marginal cost. To do so, define an aggressive strategy as follows.

Definition 4. The bid function σ_i: $U \rightarrow \beta$ is an aggressive strategy if for any σ_j: $U \rightarrow \beta$ it induces an outcome $O=(q_i,q_j,P)$ such that $c(q)>P$ for all $q>q_i$.

Marginal cost bidding is an example of an aggressive strategy. The first result characterizes bidding by the non-price-setter.

Lemma 1. *Suppose σ is a Nash equilibrium of a multi-unit auction with complete information. If firm i is the Price Setter, then σ_j is an aggressive response to σ_i.*

Proof. Let σ_j be a strategy such that $O(\sigma_i, \sigma_j)=\{q_i,q_j,P\}$ for which firm i is the price setter and there exists a value $\hat{q}>q_j$, such that $c(\hat{q})<P$.

$$\text{Let } \sigma_j'(q) = \left\{ \begin{array}{c} \sigma_j(q) \text{ iff } q \neq q_j+1, \\ P^* \in (c(q_j+1), P) \text{ otherwise} \end{array} \right\} \text{ and evaluate } \pi_j(\sigma_i,\sigma_j) \text{versus } \pi_j(\sigma_i,\sigma_j').$$

Notice that the new clearing price would depend on whether firm j becomes the price-setter. If firm i is still the price-setter for strategies (σ_i, σ_j'), then the clearing price must be greater than P^*. Hence, P^* is a lower bound on the price resulting from the outcome $O(\sigma_i, \sigma_j')$ and we can say that $\pi_j(\sigma_i,\sigma_j') \geq P^{**}(q_j+1) - \sum_{n=1}^{q_j+1} c(n)$, and $\pi_j(\sigma_i,\sigma_j) = Pq_j - \sum_{n=1}^{q_j} c(n)$. Let $P-P^*=\gamma$. Given these values, we can evaluate $\pi_j(\sigma_i,\sigma_j') - \pi_j(\sigma_i,\sigma_j)$ to be

$$\pi_j(\sigma_i,\sigma_j') - \pi_j(\sigma_i,\sigma_j) \geq P^* - c(q_j+1) - \gamma q_j \tag{6}$$

By substituting $P-\gamma$ for P^*, we can express this as

$$\pi_j(\sigma_i,\sigma_j') - \pi_j(\sigma_i,\sigma_j) \geq P - \gamma - c(q_j+1) - \gamma q_j \geq P - c(q_j+1) - \gamma(q_j+1) \tag{7}$$

Thus, if γ can be made arbitrarily small and $p - c(q_j + 1) > 0$, then there is a P^* such that $\pi_j(\sigma_i, \sigma_j') - \pi_j(\sigma_i, \sigma_j') > 0$. □

The intuition for Lemma 1 can be obtained by relating bidding behavior at the margin to Bertrand competition with asymmetric costs. In this model, units are discrete and the non-price setter has incentives to undercut or tie any clearing price that is greater than the marginal cost of it's marginal unit. If, for example, firm i is pricing units out of the market, then the marginal cost of firm i's marginal unit is less then the marginal cost of firm j's marginal unit. This is true even when firms have identical marginal cost functions. As such, the firm that is pricing out units has an incentive to undercut the marginal cost of the other firms' marginal unit and become the unique price-setter.

A.2.2. Bidding behavior by the price setter

Lemma 1 greatly simplifies the price-setter's problem. The definition of Nash equilibrium and Lemma 1 require that the price setter is playing a best response to an aggressive response (i.e. marginal cost) strategy. This defines the price-setter's residual demand curve and the resulting optimal price.

Definition 5. If firm i is the price setter in a multi-unit auction with complete information, then σ_j induces the residual demand

$$D_i(P) = \begin{cases} M - \max\{q_j : c(q_j) < P\} + 1/2 & \text{if} \quad P = c(q_i) = c(q_j) \\ M - \max\{q_j : c(q_j) < P\} & \text{otherwise} \end{cases} \tag{8}$$

Definition 6. Suppose σ is a Nash equilibrium of a multi-unit auction with complete information. If firm i is the price setter, then $P = c(q_j + 1)$.

Given Definitions 5 and 6, the price setter's best response to an aggressive strategy can now be simplified into a single objective function. Throughout this paper we will often express quantities in terms of their differences from the "null" quantities that firms would supply to the market if each firm chose an aggressive strategy, denoted q^o.

Definition 7. Let q_i^o be the realized output of firm i when σ is a pair of aggressive strategies. Suppose that firm i is the price setter. The objective function of the price setter is then

$$\max_{k_i \in \{0,1,\ldots,q^o\}} (q^o - k_i)[c(q^o + k_i + 1)] - C(q^o - k_i). \tag{9}$$

Crespo (2001) shows that this profit function is concave in q. The price-setter's optimal quantity, $q^* = q^o - k^*$, and price are then given by

$$\begin{aligned} k_i^* = {} & \max k_i \in \{0, 1, \ldots, q^o\} \text{ such that } (q^o - k_i)[\Delta c(q^o + k_i + 1)] \\ & -[c(q^o + k_i) - c(q^o - k_i)] \geq 0. \end{aligned} \tag{10}$$

Definition 8. Let $P_i^* \equiv c(q^o + k_i^* + 1)$ be the optimal price chosen by firm i when firm j plays an aggressive strategy.

Lemma 2 states the essential properties of the Bid Function Equilibrium.

Lemma 2. *If σ is a Nash equilibrium of a multi-unit auction with compete information and firm i is the price setter, then the outcome $O(\sigma)=(q_i,q_j,P)$, must be of the form: $q_i=q^o-k_i^*$, $q_j=q^o+k_i^*$, and $P=P_i^*$.*[53] *This equilibrium will also be referred to as a Bid Function Equilibrium.*

Proof. Suppose that σ is a pure strategy Nash equilibrium where firm i is the price setter.

i) Verify that if $P=P^*$, then $q_j=(q^o+k_i^*)$ or $(q^o+k_i^*+1)$.

From Lemma 1 we know that if $\hat{q}>q_j$ then $c(\hat{q})>P$. This imples that for the price, $P_i^*=c(q^o+k_i^*+1)$, it must be true in a PSNE that $q_j+1\geq(q_o+k_i^*+1)$ and hence $q_j\geq(q^o+k_i^*)$. Furthermore, we know that any outcome for which $c(q_j)>P$ cannot be the outcome of a PSNE. Hence, $q_j\leq(q^o+k_i^*+1)$. Together, these two conditions imply that $(q^o+k_i^*)\leq q_j\leq(q^o+k_i^*+1)$. In part (ii) of the proof, it will be shown that only $q_j=(qo+k_i^*)$ can be part of the equilibrium.

ii) Verify that if $q_j=(q^o+k_i^*+1)$ then $P\neq P^*$:

In a PSNE for which $q_j=(q^o+k_i^*+1)$ it is not possible for P to equal P^* because firm i could then raise the clearing price to $c(q^o+k_i^*+2)$ without changing (q_i, q_j). Clearly, $c(q^o+k_i^*+2)q_i-\sum_{n=1}^{q_i}c(n)>c(q^o+k_i^*+1)q_i-\sum_{n=1}^{q_i}c(n)$.

iii)Verify that if $q_j=(q^o+k_i^*)$, then $P=P^*$.

If $q_j=(q^o+k_i^*)$ then any outcome for which $P>P^*$ would be a violation of Lemma 1 because σ_j would no longer be an aggressive response to σ_i. If $P<P^*$ then Lemma 1 implies that firm 1 can increase price by setting $\sigma_i(q_i)=P^*$ without changing (q_i,q_j). Together, (i), (ii), and (iii) imply that if $P=P^*$, then $q_j=(q^o+k_i^*)$ and if $q_j=(q^o+k_i^*)$ then $P=P^*$.

iv) Verify that there is a solution k_i^*.

Given (i), (ii), and (iii), firm i has the objective function

$$\max_{k_i\in\{0,1,\dots,q^o\}}(q^o-k_i)[c(q^o+k_i+1)]-C(q^o-k_i)$$

Since k_i^* must be chosen from a finite set of values, there must be at least one solution for k_i^*. Also note that the price, $c(q^o+k_i+1)$, is strictly increasing in k (or decreasing in q_i). Therefore, the discrete profit function is similar to the infinitely divisible case in that it resembles a function that is concave with respect to the choice variable q_i. Still, the discrete function may not be defined at unique maximum of the infinitely divisible case. As a result, there may be at most, two values for k_i^*. □

A.2.3. Bids away from the margin

Lemma 2 describes properties of BFE at the margin, i.e. for the marginal units for each firm. Equilibrium, however, also imposes bounds on bids for units away from the margin. These are briefly described and motivated here. See Crespo (2001, pp.11–15) for more details.

There are four sets of bounds, one each for infra- and extra-marginal units for each of the price-setter and non-price-setter. The bounds for the extra-marginal (Right) units are:

$$R_1:[(\sigma_1(q_1+n))-\sigma_1(q_1)](q_{2-m})\leq\sigma_1(q_1)m-\sum_{q=q_2-m}^{q_2}c_1(q),\ \text{or}$$

$$(\sigma_1(q_1+n))-\sigma_1(q_1)\leq\frac{\sigma_1(q_1)m-\sum\limits_{q=q_2-m}^{q_2}c_1(q)}{(q_2-m)} \tag{11}$$

[53] It should be noted that when firms are asymmetric in their cost functions, then it is possible that only one firm can be the price setter. For example, if $\sum_{q=1}^{q_1^0-k_1^*}P_1^*-c_1(q)\geq\sum_{q=1}^{q_1^0+k_2^*}P_2^*-c_1(q)$, then only firm 1 can be the price setter.

$$R_2: [(\sigma_2(q_2+n))-\sigma_1(q_1)](q_{1-m}) \leq \sigma_1(q_1)m - \sum_{q=q_1-m}^{q_1} c_2(q), \text{ or}$$

$$(\sigma_2(q_2+n))-\sigma_1(q_1) \leq \frac{\sigma_1(q_1)m - \sum_{q=q_1-m}^{q_1} c_2(q)}{(q_1-m)} \tag{12}$$

The bounds for the infra-marginal (Left) units are:

$$L_1: \sigma_1(q_1-m) \leq P^* \tag{13}$$

$$L_2: q_1[(\sigma_1(q_1))-\sigma_2(q_2-m)] \geq [\sigma_2(q_2-m)](m) - \sum_{q=q_1}^{q_1+m} c(q), \text{ or} \tag{14}$$

$$(\sigma_1(q_1))-\sigma_2(q_2-m) \geq \frac{[\sigma_2(q_2-m)](m) - \sum_{q=q_1}^{q_1+m} c(q)}{q_1}$$

A.3. Existence and uniqueness

A.3.1. Existence

These bounds are used in Theorem 1 to prove the existence of a Nash equilibrium.

Theorem 1. *In any game $\Gamma_1 = \langle (1, 2), \beta, U, (\pi_i), M \rangle$ representing a multi-unit auction with complete information, there exists a Nash equilibrium, σ, that results in outcome $O(\sigma) = (q_i, q_j, P)$, where $q_i = q^o - k_i^*$, $q_j = q^o + k_i^*$, and $P = P^*$.*

Proof. The proof for theorem one can be given by summarizing two preceding results. Suppose that $\sigma = (\sigma_i, \sigma_j)$ is a set of strategies that satisfy i) the requirements given by Lemma 2, and ii) the requirements given by the left hand and right hand criteria (L_1, L_2, R_1, R_2) above. Lemma 2 tells us that the bid price of the marginal unit is consistent with the requirements of Nash equilibrium. The right hand and left hand criteria are that neither firm can change the bid prices of an extra-marginal or infra-marginal unit to improve their own profits. Furthermore, we can confirm that these bid functions always exist.

First, recall that the four criteria merely place an upper bound on extra-marginal prices, and an upper bound on infra-marginal prices. Also note that for any $i \in (1, 2)$,

i) the upper bound on $\sigma_i(q)$ is increasing as q increases away from q_i^* and is always greater than P, and
ii) the upper bound on $\sigma_i(q)$ is decreasing as q decreases away from q_i^* and is always less than P.

This implies that there will always be at least one set of monotone bid functions that satisfy both Lemma 2 and the bounds in Eqs. (11)–(14). Therefore we can conclude that $\pi_i(\sigma_j,\sigma_i) \geq \pi_i(\sigma_j, \tilde{\sigma}_i)$ and $\pi_j(\sigma_i,\sigma_j) \geq \pi_j(\sigma_i,\tilde{\sigma}_j)$ for any $\tilde{\sigma}_i$ and $\tilde{\sigma}_j$ that are mappings from U into β. □

A.3.2. Uniqueness

While PSNE can be shown to exist, there is no guarantee that they are unique. Indeed, for a given price-setter, there are many candidate bid functions for the price-setter and non-price-setter that satisfy the requirements for equilibrium: any that satisfy the marginal conditions in Lemma 2 and don't violate the bounds in Eqs. (11)–(14) qualify. Furthermore, for symmetric firms, there are always at least two (identical) equilibria that differ only in the identity of the price setter.[54]

Despite the lack of uniqueness away from the margin, Lemma 2 ensures equilibrium *outcomes*, (q_i^*, q_j^*, P), are unique at the margin (for a given price-setter). It is for this reason we focus our empirical tests on these units.

Appendix B. The England and Wales market for electricity

The England and Wales (hereafter EW) market for electricity was among the first to deregulate the market for wholesale generation of electricity. In April, 1990, the UK began privatizing the markets for generation, transmission, and distribution of electricity. The generation assets of the extant monopoly were sold and an electricity "Pool" was established as the primary wholesale (spot) market for electricity. A separate transmission grid company, the National Grid Company (NGC), and 12 Regional Electricity Companies (RECs) were also created to transmit and distribute electricity to final customers. While the NGC and RECs remained subject to regulation during the time period considered in this paper, the spot market was unregulated and presumed to be competitive.

This section briefly describes salient features of the EW spot market for electricity.[55] Specifically, we characterize the market rules, the market structure, and the nature of generation technology in the market, and briefly survey analysis of the performance of the market to date. Interested readers should refer to Wolak and Patrick (2001) and Wolfram (1998) for additional details.

B.1. Market rules

The rules for bidding into the spot market during the time period considered in this paper are as follows:

1. Demand is forecast by the NGC for each half-hour of the following day.[56]
2. Each generator submits bid prices for each generating unit it is willing to make available *for any and all half-hour markets* of the following day. A generating unit is usually one turbine in a generating plant.[57]
3. The NGC uses these bid functions to obtain an aggregate supply curve.
4. In each half-hour, it selects units to minimize cost subject to reliability constraints.
5. The intersection of the bid price of the marginal unit and forecast demand determines the System Marginal Price (SMP) paid to all units utilized in that half-hour.

[54] If firms are very asymmetric, this duplicity of equilibria can disappear as the large firm may have an incentive to price out units even if the small firm is already doing so. In this case, the only equilibria are those with the large firm as price-setter.

[55] Spot markets are often just one component of a deregulated generation market. Secondary markets are often used to complement the spot market and to provide hedging against price volatility. Bilateral contracts for power and their financial equivalents, "contracts for differences", play a similar role. As the spot market can be viewed as the competitive engine of a deregulated generation market, we focus our efforts there. See, however, Wolak (2000) and Bushnell and Wolak (1999) for an analysis of the impact of such entities on strategic bidding in electricity markets.

[56] The forecasting algorithm is available to generators and they are capable of deriving the same forecasts as the NGC. This implies that demand is perfectly inelastic (in the short run) and known to all generators prior to bidding.

[57] A typical plant in Britain has between 2 and 11 turbines that range from under 200 to over 600 MW (Wolfram, 1998).

In practice, bids submitted to the spot market have several components, including start-up costs, ramping constraints, and no-load variable costs. Furthermore, the price paid to generators incorporates a capacity payment for providing reserves to the system in case of unexpectedly high demand.[58] In this paper, we abstract from these factors and focus on the SMP, the single price (per MWh) for electricity that accounts for the vast majority of revenue to firms during the sample period.

B.2. Market Structure and Generation Technology

At the time of privatization, two companies – National Power (NP) and PowerGen (PG) – owned the greatest shares of generating capacity in the EW market. Due to market entry by independent power producers and reductions in their own capacities, the market shares of both generators have since declined significantly. Between 1990 and 1998, NP's share of total market capacity fell from 47% to 30% and PG's has fallen from 27% to 25%. (OFFER, 1998). In even more recent years, the market share of both of these generators has continued this decline.

Electricity generation is characterized by a diverse mix of technologies related to fuel type, implied marginal cost of production, and consequent pattern of use. Base load generation is utilized nearly all the time and includes large, low-cost generators. The cheapest are often nuclear and in some cases hydroelectric plants. Intermediate-cost plants include mostly coal and some oil-burning turbines. High-cost plants typically burn natural gas, although combined cycle gas turbines (hereafter, CCGT's) are highly efficient gas burning plants that are usually considered to be a part of base or intermediate load. Since privatization, there has been a significant increase in the number of new gas units along with the retirement of some less efficient coal units. Generation portfolios are important because all generators are paid a single price set by the marginal plant required to meet market demand in the spot market. It is usually the fuel-burning plants, either coal or gas, that are marginal. Since NP and PG have generation portfolios consisting almost entirely of fuel-burning plants and no nuclear plants, they have played a disproportionately dominant role in setting the SMP. During the early years of the EW market, the two generators set the System Marginal Price (SMP) over 80% of the time (Wolfram, 1998).

B.3. Performance of the spot market

Early performance of the spot market generated concern regarding the possible abuse of market power. The Office of Electricity Regulation (OFFER) monitors the UK electricity market and has documented that average pool prices increased between 1990/91 and 1994/95 before reversing course and falling between 1994/95 and 1997/98 (OFFER, 1998). Concerns about the exercise of market power by NP and PG prompted several investigations of bids into the spot market by the firms. One of these investigations, released in February 1994, concluded that pool prices exceeded avoidable costs. Rather than referring the firms to the UK Monopolies and Mergers Commission (MMC), OFFER and the firms reached agreements on price levels and the disposal (via divestiture or retirement) of 6 GW of coal- or oil-fired generation.

Independent research of performance in the EW electricity market has largely substantiated OFFER's concerns. von der Fehr and Harbord (1993) estimate marginal costs and compare them to submitted bids in 1990 and 1991. They find significant differences over time in behavior with

[58] This is called the Capacity Payment (CP). Together SMP plus the Capacity Payment equals the Pool Purchase Price (PPP).

the latter bids greater than marginal costs. Following a similar approach, Wolfram (1998) considers the period 1992 to 1994 and estimates price-cost margins on marginal units in the range of 0.20–0.27.

Appendix C. Construction of the dataset

C.1. Marginal cost data

A list of all plants and their efficiency ratings was last made public in the 1987/1988 Central Electricity Generating Board (CEGB) Statistical Yearbook. Although efficiency ratings of plants are not expected to change substantially over a few years, there have been some important plant additions and plant retirements since the CEGB publication. A list of these additions and retirements is published by the Electricity Association. The plants that have been added during the 1990s include mostly combined cycle gas turbines (CCGT's). These plants convert the waste heat produced as a by product of burning natural gas into steam that can be used to power an additional turbine. Following the assumptions in Green and Newbery (1992) and Wolfram (1998), we assume that the thermal efficiencies of these plants are 45%. As pointed out in Wolfram (1999), coal plants set the SMP over 80% of the time, so it is helpful to have precise estimates of the marginal costs associated with these plants. For this reason, we substitute more recent measures of efficiency ratings of coal plants published in Rainbow, Doyle, and Price (1993) where they differ significantly from those published in the CEGB Statistical yearbook.

At the time of privatization, regulators and industry representatives were concerned about the effects of competition in generation on the nation's large but vulnerable coal industry. Due to this concern, generators were "locked in" to purchase prices for coal in contracts that started at 150 pence per gigajoule in March 1993 and were lowered periodically to 134 pence per gigajoule in 1995. For coal prices before this period, and the prices of other fossil fuels, we use those published quarterly in the periodical *Energy Trends*. *Energy Trends* published the average of the actual fuel prices paid by generators. Since generators purchase much of their needed fuels at prices based on long term contracts and these can differ from the spot market prices, the Energy Trend prices are more accurate than a spot market price.

For non-fossil fuel plants, we use the same procedure for approximating marginal cost as in Green and Newbery (1992) and Wolfram (1999). The marginal costs of pumped storage plants and electricity imported from France and Scotland are approximated by the minimum bid prices that were submitted during the same quarter year. The marginal costs of nuclear units are approximated to be between 11 and 13 British pounds per megawatt-hour according to the technology used by the reactor.

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