Strategic Behavior in Spot Markets for Electricity when Load is Stochastic

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Abstract

In the first part of the paper, daily price data for the past three summer seasons in the PJM wholesale market are used to estimate a stochastic regime switching model. These data show that the average price in 1999, when market-based offers were allowed, was twice as high as it was in the previous two seasons when offers had to be cost-based. The primary cause was that the price spikes in 1999 were much higher than they were in 1997-98, but not more frequent. The second part of the paper derives an optimum set of offers for individual suppliers endowed with different levels of market power. A supplier controlling generation equivalent to 20% of the expected load in the market is shown to submit offers that are up to 80% higher than the true cost. Nevertheless, these offers are still much lower than the offers that set the high prices in the PJM market. The explanation is that suppliers with sufficient market power are indifferent to whether or not marginal units are dispatched, and they can set high offers on these units without forfeiting expected profits.

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1. Introduction

The flagrant use of market power to raise prices above competitive levels in the UK market for electricity has been discussed extensively in the literature (Littlechild (1998), Newbery, (1995), von der Fehr and Harbord (1993), Wolak (1997), and Wolak and Patrick (1997)). Tests of different auction mechanisms in an experimental setting confirm that excess profits can be extracted when the number of players is less than six (Bernard *et al.* (1998)). Backerman *et al.* (1997) show that two suppliers can successfully capture congestion rents in an electricity market. In spite of this abundant evidence, regulators in the USA have been relatively unconcerned about the emerging pattern of ownership of generating capacity. The fact that a bundle of power plants could be sold for a higher price than the sum of individual sales has been viewed as a way to cover the cost of strandable assets, and not as a sign of market power in the future. This behavior is completely different from the strategy followed in Victoria, Australia, which required that each power plant should be sold to a different company (Outhred (1997)). It is interesting to note that average prices in the Australian wholesale market have dropped substantially. Current evidence from the USA, however, is more ominous, with many reports in the news of high price spikes in different regions of the country.

Evidence of higher prices is presented in Section 2. Daily price data for the PJM East market are used to estimate a stochastic regime switching model developed by Hamilton (1994). This model has been shown to work well for electricity prices in a number of different markets (Ethier and Mount (1999)). In 1997 and 1998, the wholesale market in PJM used a uniform-price auction with offers to sell power based on actual costs. In 1999, market-based offers were allowed, and at the same time, the average price doubled from the previous years. The estimated parameters show that market behavior was a factor in making prices higher in the high-price regime in 1999, but the frequency of occurrence of the high-price regime was similar in 1999 to the earlier years. Hence, the implication is that market power is probably the reason for the higher prices in the high-price regime.

Sections 3 and 4, the optimum offers for an individual supplier are derived to maximize the expected net revenue above operating costs. Two different suppliers are considered to illustrate the potential for exploiting market power. One controls 20% of the generating capacity needed to meet expected load and the other only 4%. The total load on the system is specified to have a symmetric probability density function. A competitive supply function (i.e., the true marginal costs of generating) is specified with both first and second derivatives positive. The implication is that the variability of load will generate a density of prices that is slightly skewed towards high prices, but not nearly as much as the observed skewness in the PJM market. Hence, the objective is to determine

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whether market power will distort the density of prices and explain observed price behavior.

The optimum offers provide few surprises from a conventional economic analysis of market power. The supplier with 20% of the capacity makes offers that are substantially higher than both the true marginal costs and the supplier with only 4% of the capacity. Furthermore, the offers on the marginal units with high costs are more distorted upwards than the offers for base-load units. The optimum offers are relatively robust to changes in the density of load. Hence, the formal results do not provide a clear explanation of why price spikes occur. The highest offer for the large supplier is only $54/MWh, compared to a true cost of $30/MWh, and this is much less than the prices over $200/MWh that were observed in the PJM market last summer.

The discussion in Section 5 gives an explanation of why very high offers are submitted. The optimum offer on a marginal unit submitted by a supplier with market power is high enough to make it highly unlikely that the unit is ever dispatched. This indifference to having marginal units dispatched implies that there is no penalty, in terms of lower expected profits, from submitting an even higher offer. This is not the case with a small supplier facing similar costs. The overall result is that whenever almost all available capacity is needed to meet load, the marginal units with high offers must be dispatched and price spikes occur.

2. Evidence from PJM

A wholesale market for bulk power in Pennsylvania, New Jersey and Maryland (PJM) has been operating since April 1997. Prior to April 1999, the rules for the auction required that suppliers submit cost-based offers to sell power. This year the rules were modified to allow market-based offers (some suppliers have chosen to continue submitting cost-based offers). Average weekday prices for the peak period (6 a.m. to 10 p.m.) are shown in Figure 1 for the three summer seasons. It is clear that peak prices were higher in 1999 when market-based prices were allowed. This phenomenon could be caused by unusually hot weather or it could be caused by market power. Although data on actual offers are not publicly available, it seems highly likely that the peak prices of well over $200/MWh were set by large suppliers with control over substantial amounts of generating capacity and not by small suppliers who control a single expensive peaking unit. The basic logic is that there is little cost to speculating with a few marginal units in a large portfolio of generators. The possibility of setting a high price on rare occasions is adequate compensation for having lower capacity factors on the marginal units.

The difference in the price behavior before and after market-based offers were allowed in the PJM market can be illustrated using a stochastic regime-switching model proposed by Ethier and Mount (1999). In this model, each regime is specified as a mean reverting process for the logarithm of price, and a Markov switching process determines which regime is observed. One regime has a relatively low mean value with low volatility, and the other regime has both a high mean and a high volatility. The probability of being in the high-price regime is relatively small, but the expected duration of high peaks is typically longer than it would be with a simple binomial process, (Hamilton and Susmel (1994)).

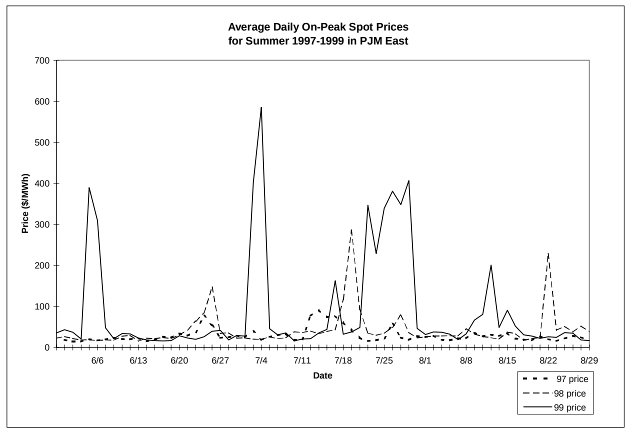

Figure 1

The maximum likelihood estimates of the parameters are summarized in Table 1 for the cost-based auction and for the market-based auction. The first thing to notice is that the mean for the high-price regime is substantially larger under the market-based auction. The low-price mean and the two standard deviations have similar values under cost-based and market-based auctions. The mean prices for the low-price regime are $25/MWh and $31/MWh for the cost-based and market-based auctions, respectively. While the increase of 22% in the mean price from the switch to a market-based auction is not a trivial amount for customers, it is small compared to the increase of 268% from $67/MWh to $231/MWh in the high-price regime. The combined effect for the two regimes is to double the weighted mean price from $33/MWh to $67/MWh in the market-based auction.

Table 1. Estimated Parameters for the Stochastic Price Process in PJM

	Cost-based Auction (1997/98)	Market-based Auction (1999)
Low-price regime		
Mean	3.24	3.42
Standard deviation	0.05	0.11
High-price regime		
Mean	4.09	5.41
Standard deviation	0.30	0.24
Other parameters		
Adjustment rate	0.52	0.52
P{Stay in low regime}	0.92	0.91
P{Stay in high regime}	0.64	0.59
Derived parameters		
Low mean price	25.46	31.05
High mean price	62.69	230.83
Ergodic P{High regime}	0.19	0.18
Long-run mean price	32.53	67.01

One surprise about the models in Table 1 is that the estimated probabilities for the Markov switching process are quite similar for the cost-based and market-based auctions. The ergodic probabilities of observing the high-price regime (the long-run average probability of being in the high-price regime) are 0.19 and 0.18 for the cost-based and market-based auctions, respectively. One might have expected that price spikes would occur more frequently in a market-based auction if large suppliers were able to exploit market power. The results in Table 1 suggest that this is not the case.

The PJM system was under "stress" roughly 20% of the time during the past three summers when generators with high offers were needed to meet load. However, suppliers were able to exploit these situations much more effectively in a market-based auction than they were in a cost-based auction. The implication is that market power may exacerbate bad situations when the power system is stressed. While this conclusion can only be a speculation as long as information on actual offers is unavailable, it does underline the need to understand the pricing behavior of suppliers when load is stochastic. The question addressed in the following sections is how does the uncertainty of load get amplified by the structure of offers to sell power. In other words, under what conditions is it rational for a supplier to submit offers that are substantially above the true marginal cost of generating power? Although being a large supplier increases the potential for exploiting market power, as expected, the results show that the true structure of costs for a large supplier is also an important factor.

3. Economic conditions faced by a supplier

The analytical approach in this paper is to specify a simple model of the net demand for power from a single supplier and to derive the optimum structure of offers to sell that power using numerical techniques. Hence, the results are conditional on the particular empirical specifications adopted. The justification for this approach is that the problem is complex and the formal analytical results do not illuminate the issue of price volatility effectively. Since the results are dependent on the empirical specifications, the objective of this section is to provide a rationale for the structure of the model and the values of the parameters.

The results in the previous section demonstrate that the stochastic behavior of prices can be represented by a Markov switching model with two mean-reverting regimes. In an earlier paper, Mount (1999) showed how the uncertainty of load is transformed into uncertainty about the spot price in a uniform price auction, and how market power exacerbates the volatility of prices. A piece-wise linear supply curve for all suppliers was used, and in effect, the existence of two different price regimes was built into the initial specification of the model. While this specification was adequate for the purposes of the paper, a supply curve with three linear segments does not represent the aggregate supply for a real market very accurately. Hence, an underlying objective of this analysis was to specify a smooth marginal cost curve for the industry and to see whether the behavior of suppliers in the auction results in different price regimes. Using the same rationale, the uncertainty about load was specified as normally distributed, rather than as a skewed bimodal density, for example. The important implication of these specifications is that the derived density of prices does not exhibit regime switching under competitive or cost-based pricing.

The analysis identifies two different suppliers in a market which has an expected load of 25,000MW. The "large" supplier controls 5,000 MW of capacity, corresponding to 20% of the expected load. The "small" supplier controls only 1,000 MW or 4% of the expected load. The two suppliers are assumed to control capacity of different types representing the full range of operating costs. Under cost-based pricing, the supply curve starts at a negative value and increases at an increasing rate to give a price of $30/MWh at the expected load of 25,000 MW. The rationale for this shape follows the conclusions in Ede *et al.* (1999) which show that offers for some units of base-load capacity may be negative to offset the possibility of not being dispatched and incurring startup costs in a subsequent period. Using the same logic, offers for peaking units may be higher than the marginal production costs because it does not pay to operate unless startup costs as well as production costs are covered. Hence, in a cost-based auction, the supply curve is convex to the origin and the probability density function (pdf) of prices will be skewed to the right even if the pdf of load is symmetric.

The supply curve for all suppliers is specified as the following power function with an exponent greater than one so that both the first and second derivatives are positive (system losses are assumed to be zero).

Industry Supply Curve

$$P = a + b\,(Q/1000)^{c} \qquad (1)$$

where P is the market price ($/MWh)
Q is the actual load (MW)
a = -10
b = 0.064
c = 2

The reason for choosing the form in (1) is that it is monotonic and the inverse function for Q is easy to derive. The skewness of the pdf of P increases as c increases. Inspection of Figure 2 suggests that that curvature of the supply curve is modest when c = 2. However, some results for c = 4 are also discussed in Section 5.

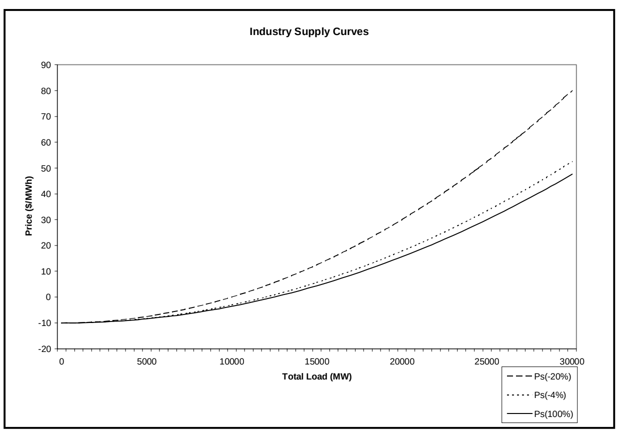

Figure 2

The net demand faced by an individual supplier is derived by specifying a supply curve for all other suppliers, which is simply a scaled version of the industry supply curve. Using this approach, the net demand faced by a single supplier can be written as follows:

Net Demand Curve for a Supplier

$$P = a + b(1\text{-}R)^{-c}\,((Q - q) / 1000)^{c} \qquad (2)$$

where q is the load generated by the supplier,
R is the share of total capacity controlled by the supplier (0.2 or 0.04)

The supply curves in Figure 2 correspond to the total industry (Ps (100%)), all suppliers except the large supplier (Ps (-20%)), and all suppliers except the small supplier (Ps (-4%)). There are no hard limits on the total available capacity in the model, and this is an issue that is discussed again in Section 5. It is assumed that high levels of load can be met by importing some power from other regions if the total installed capacity in the market is exceeded.

The corresponding net demand curves for the two individual suppliers are shown in Figure 3, evaluated at the expected load (Q = 25,000MW). The two important characteristics of these demand curves are 1) the demand curve for the large supplier is higher, and 2) the slope for the large supplier is more negative. The latter characteristic is the indicator that the large supplier has more potential to exploit market power (a flat demand curve would make it impossible to exploit market power, corresponding to the ideal competitive market).

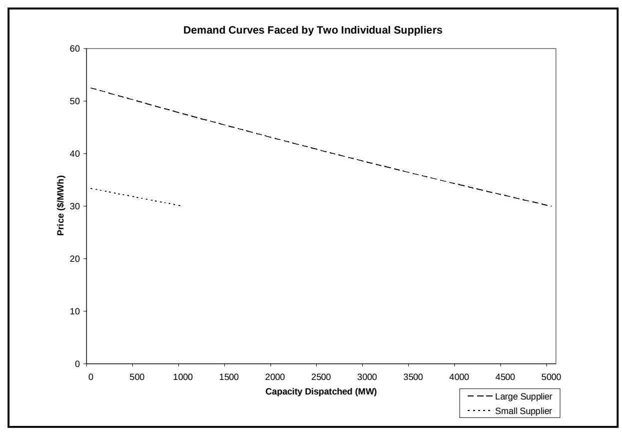

Figure 3

Cost curves for each supplier must be specified to complete the economic framework faced by a supplier. For this step, the specification departs from the strict logic of the functional forms in (1) and (2). The justification for this is that it is desirable to identify discrete units of capacity, and the associated costs, explicitly in the model. As a result, the corresponding offers to sell power will be similar in form to the offers made in real markets. The crucial assumption in the analysis is that the net-demand curves in Figure 3 are good approximations to the subjective views held by the two suppliers. It seems reasonable to assume that a simple smooth form for the subjective net-demand curves is appropriate because detailed information about other suppliers is not publicly available (the type of information that should be shared among the suppliers is an important question that will affect the performance of the auction).

The marginal cost curves for the two suppliers are specified as step functions in Figure 4. The structure of costs is essentially the same for both suppliers. Half of the capacity is base-load at \$10/MWh, another 30% of capacity costs \$15/MWh, and the final 20% of peaking capacity costs \$30/MWh. The implication is that with an efficient cost-based auction, both suppliers should have all of their capacity dispatched at the expected load of 25,000MW and a market price of \$30/MWh. Given the symmetric pdf of load, both suppliers will be fully dispatched 50% of the time, and for some of the time, they will be setting the market price. In fact, the structure of costs was specified to ensure that both suppliers have an opportunity to exploit any market power that they possess. In the next section, the optimum offer curves for the two suppliers are derived for a specific pdf of load.

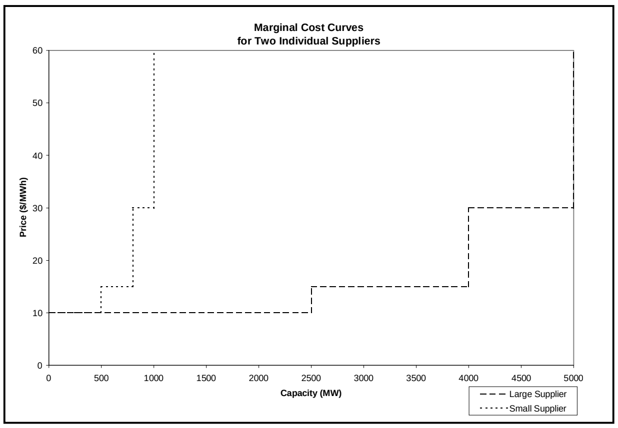

Figure 4

4. Optimum offers to sell power

Given the demand and cost conditions faced by the two suppliers specified in Section 3, it is possible to derive the offers that maximize expected profits for each supplier (strictly speaking, these are net returns above operating costs.) The total load on the system is specified to be Normal (25,000, $2{,}000^2$), implying that the expected load is 25,000 MW and the load exceeds 30,000 MW less than one percent of the time. Using the industry supply curve shown in Figure 2, the market price would be \$30/MWh at the mean load and range from roughly \$16/MWh to \$48/MWh, corresponding to loads of 20,000 MW and 30,000MW, respectively. Note that the pdf of prices is skewed to the right, but not dramatically so, and certainly far less than the actual pdf of prices estimated for a market like PJM.

The variance of the pdf of load is relatively large if it is viewed as the forecasting error in a day-ahead market, but it is reasonable if it is considered to represent the variability of peak daily loads during a summer season. The range of prices corresponds to typical marginal costs for base-load units at the low end and for peaking units at the high end. Furthermore, it will be shown later that the optimum offers are not affected appreciably for a wide range of values of both the mean and the variance of load.

For the following analysis, it is assumed that offers are submitted for fixed amounts of capacity that correspond to the structure of costs in Figure 4. The most expensive block of capacity is divided into two equal pieces so that offers are made for the following units (the true marginal costs are given in parentheses):

Offer_1	0 – 50% of capacity	(\$15/MWh)
Offer_2	51 – 80% of capacity	(\$20/MWh)
Offer_3	81 – 90% of capacity	(\$30/MWh)
Offer_4	91 – 100% of capacity	(\$30/MWh)

Each offer can be evaluated separately and the basic objective is to determine the level of the offer that maximizes the expected profit. It is not rational to submit offers below marginal cost because no start-up costs are incurred in this model. Consequently, the optimum offer is greater than or equal to the true marginal cost. A grid search is used to determine the optimum offer for each block of capacity starting with the unit with the highest marginal cost (MC).

For any offer, one of the following four possible outcomes is determined by the market price, P:

1. $P < MC \le \text{Offer}$ → Not dispatched
2. $MC \le P < \text{Offer}$ → Not dispatched
3. $MC \le P = \text{Offer}$ → Partially dispatched
4. $MC \le \text{Offer} < P$ → Fully dispatched

For the first outcome, the expected profit above marginal cost pricing is always zero, and as a result, the potential for earning excess profits above competitive levels is limited to outcomes 2-4. For outcome 3, the unit offered is setting the market price. If Profit* is defined as the excess profit above marginal cost pricing, the objective of the supplier is to submit the offer that maximizes the following expression:

$$
\begin{aligned}
E[\text{Profit}^*] = & \int_{Q_H}^{\infty} q_H (P[Q,q_H] - MC)\, f[Q]\,dQ + \\
& \int_{Q_L}^{Q_H} q[Q,\text{Offer}]\,(\text{Offer} - MC)\, f[Q]\,dQ + \\
& \int_{Q_{MC}}^{Q_L} q_L\,(P[Q,q_L] - MC)\; f[Q]\,dQ
\end{aligned} \qquad (3)
$$

where q_H is the capacity supplied if the offer is accepted

q_L is the capacity supplied if the offer is declined

$(q_H - q_L)$ is the size of the unit offered
Q is the total load in the market
f[Q] is the pdf of Q
P[Q,q] is the market price in (2)
MC is the marginal cost
Q [q, Offer] is the inverse function of (2) when P = Offer
$Q_H = Q[q_H, \text{Offer}]$ is the minimum load for full dispatch of the unit
$Q_L = Q[q_L, \text{Offer}]$ is the maximum load when the unit is not dispatched
$Q_{MC} = Q[q_L, MC]$ is the load at the marginal cost MC.

The optimum offer that maximizes (3) was determined numerically using *Mathematica* to perform a grid search for different levels of the offer above the true marginal cost. The results for the large supplier with 20% of total capacity and the small supplier with 4% of total capacity are summarized in Tables 2 and 3. The optimum offers in Table 2 illustrate the basic difference between a supplier with a lot of market power and one with little. The offers for the large supplier are all substantially higher than the true marginal costs and the corresponding offers made by the small supplier. Furthermore, the degree of distortion of the offers from the competitive solution increases as the percentage of capacity affected increases. The highest offer of $54/MWh is 80% above the marginal cost, while the lowest offer of $16/MWh is 60% above the marginal cost. These general results are consistent with the standard theory of behavior in a multi-unit auction developed by Ausubel and Cramton (1996), and also with the results in Mount (1999) for a supplier facing a deterministic demand curve. In other words, there are no major surprises from introducing stochastic load to the problem of determining optimum offers.

Table 2. Optimum Offers ($/MWh)

	Capacity Offered	Suppliers		True Cost
		Large	Small	
1.	0% - 50%	16	11	10
2.	51% - 80%	28	17	15
3.	81% - 90%	51	33	30
4.	90% - 100%	54	33	30

Table 3. Expected Profits ($/hour)

	Large Supplier	Small Supplier
Optimum offers	90,458	9,818
Competitive offers	82,208	9,758
Excess profits	8,250	60

The results in Table 3 show the expected profits from submitting the optimum offers in Table 2 and from submitting competitive offers equal to the true marginal costs. The expected excess profit of $60 per hour for the small supplier is very low (even if it is scaled by a factor of five to make the capacity offered equal to the capacity of the large supplier). The large supplier makes an expected profit of $8,250 per hour under the specified conditions (almost $8 million for a summer of 60 week days with 16 hours on peak each day).

The results are also summarized in Figures 5-8. For these four figures, the results for the small supplier are multiplied by five to make them directly comparable to the large supplier. Consequently, the results represent one large supplier and the combined capacity of five identical small suppliers. Figure 5 shows the optimum offers that are presented in Table 2. Figure 6 shows the corresponding total revenues and costs for different levels of capacity dispatched. The corresponding profits are shown in Figure 7 and the excess profits above competition in Figure 8. The excess profits in Figure 8 are much higher than the values in Table 3. The reason is that the profit levels when all units are dispatched are not likely to occur. Submitting a high offer of $54/MWh, for example, is almost equivalent to withdrawing the unit from the market.

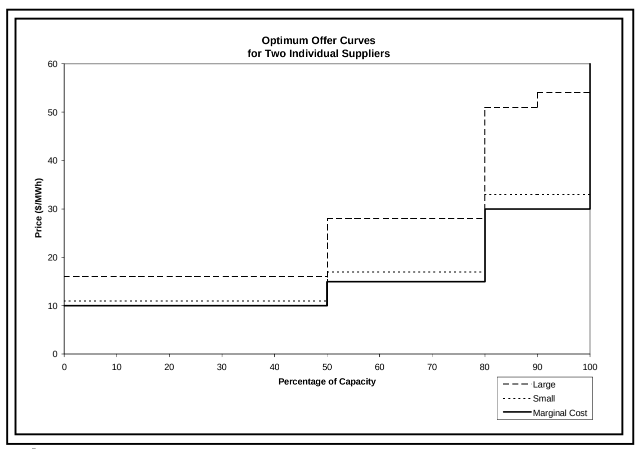

Figure 5

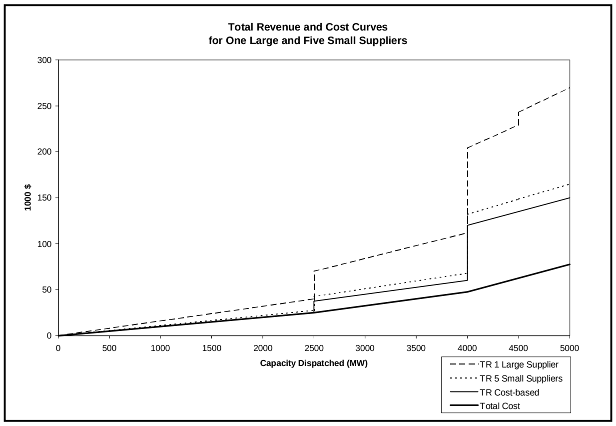

Figure 6

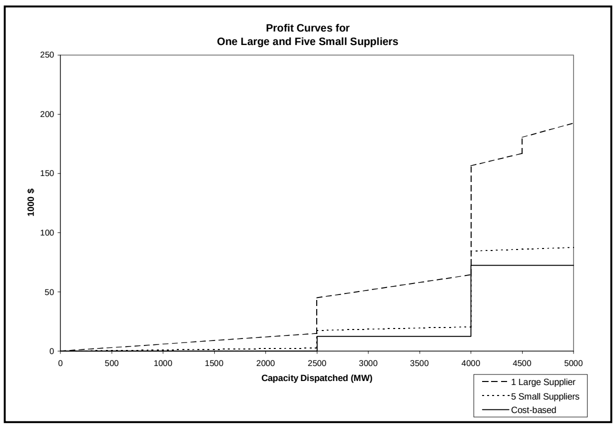

Figure 7

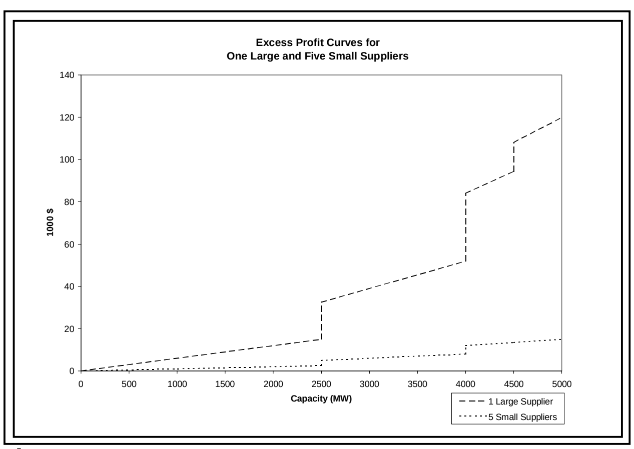

Figure 8

If it is assumed that all other suppliers in the market use cost-based pricing, then the market clearing price will be determined by the intersection of the net demand curve in (2) with the offer curve. Using this assumption, the market clearing prices and capacities dispatched for different levels of load are shown in Table 4. The main differences between the large supplier and the five small suppliers occurs at low loads. For a load of 20,000 MW, the large supplier raises the market price to $21/MWh, compared to $17/MWh with the small suppliers, by having less capacity dispatched. The extra pure profit of $10,000 = 2,500 (21-17) is more than enough to compensate for the foregone profit on the additional capacity of $2,136 = (3568 – 2500) (17 – 15). At the high load of 30,000MW, the large supplier gets all but 300 MW dispatched and the small suppliers are fully dispatched. There is little difference in price between the large supplier and the five small suppliers. The small suppliers would be happy to copy the overall behavior of the large supplier if they could, but they can not do it. The demand curve that they face is much flatter than it is for the large supplier, and the probability of setting the market price with any offer is much smaller.

Table 4. Market Clearing Prices and Quantities

		Large Supplier		5 Small Suppliers	
	Load Q (MW)	Market Price ($/MWh)	Capacity Dispatched (MW)	Market Price ($/MWh)	Capacity Dispatched (MW)
1.	20,000	21	2500	17	3568
2.	25,000	34	4000	33	4264
3.	30,000	54	4702	53	5000

The optimum offers derived in Table 2 are surprisingly robust to changes in the stochastic properties of load. Doubling or halving the variance or setting the mean to 20,000MW or 30,000MW still implies that the optimum offer on the marginal unit is $54/MWh for the large supplier. It is only if the variance gets very small and approaches the deterministic solution with Q = 25,000MW that the optimum offer drops below $54/MWh. Similarly, if the mean is increased to 40,000MW, the optimum offer is above $54/MWh. Departures from the optimum offer of $54/MWh correspond to situations in which either the unit is never dispatched or the unit is always dispatched. In both of these situations, the offer never sets the price and expected profits are essentially the same over a range of values. The implications of this feature of the optimum offers are discussed further in the final section of the paper.

5. Conclusion

The evidence in Section 2 showed that average daily prices were twice as high in the PJM market when market-based offers were allowed compared to earlier years when the auction used cost-based offers. In particular, the average price in the high-price regime was well over three times higher. The frequency of occurrence of the high-price regime remained relatively constant, however, at just under 20% of the time. The implication is that market power may have allowed suppliers to distort high-price conditions in their favor.

The results in Sections 3 and 4 derive optimum offers for a large supplier and a small supplier. Both suppliers own a portfolio of generating unit with different costs. With competitive pricing, both suppliers would be fully dispatched at the mean load, but would earn no profits on the marginal units. Since load is specified to have a symmetric pdf, the suppliers would be fully dispatched 50% of the time and set the market price some of the time, Hence, both are placed in a good position to exploit any market power that they possess.

The optimum offers shown in Table 2 and Figure 5 support conventional economic theory about market power. The large supplier distorts prices upwards much more than the small supplier. The large supplier earns excess profits of over \$8,000/hour compared to \$60/hour for the small supplier. Even so, the highest offer made by the large supplier is only \$54/MWh, compared to a true marginal cost of \$30/MWh. This value is much lower than the prices of well over \$200/MWh observed in the PJM market.

An interesting property of the results in Section 4 is that the high offer of \$54/MWh is very robust to substantial changes in the pdf of load. Hence, it is not easy to generate a higher optimum offer by simply changing the pdf of load as one might have expected. Higher offers do result if the curvature of the supply curve in (1) is increased or the supplier controls more capacity. The optimum offer is \$123/MWh when c=4 instead of 2 (with the same competitive solution of \$30/MWh at 25,000MW), and \$110 MWh when the supplier controls 50% of the capacity. Both of these situations are extreme and the optimum offer is still well below \$200/MWh. Hence, a different explanation is needed to explain why price spikes occur.

The best explanation for why suppliers submit very high offers is that they are indifferent to whether or not marginal units are dispatched because there is no loss of expected profit. Once an offer is high enough to make it highly unlikely that a unit is dispatched, it does not make any difference to expected profits if an even higher offer is submitted. These conclusions are illustrated in Table 5 which summarizes the probabilities of being fully dispatched, setting the market price, and not being dispatched for three different cases. In each case, the probabilities for the competitive solution and the optimum offer are computed, and the probability of not being dispatched (column C) is always higher using the optimum offer. For the small supplier (Case 1), there is a penalty from submitting an offer that is too high. This is also true for a large supplier if the marginal cost is well below the market price (Case 3). In both Case 1 and 3, expected profit can be much lower than the competitive solution if the offer is increased above the optimum level. Case 2 is the exception, and there is almost no penalty on profits if a higher offer is submitted because the unit will not be dispatched anyway.

Table 5. Probabilities for a Marginal Unit

	A	B	C
1. Small suppliers (MC=30, Offer=33)			
Competitive	0.50	0.02	0.48
Optimum Offer	0.33	0.02	0.65
2. Large suppliers (MC=30, Offer=54			
Competitive	0.50	0.10	0.40
Optimum Offer	<0.01	<0.01	>0.99
3. Large Supplier (MC=10, Offer=29)			
Competitive	>0.99	<0.01	<0.01
Optimum Offer	0.55	0.10	0.35

A P {Fully dispatched} (P>Offer)
B P {Sets price} (P=Offer)
C P {Not dispatched} (P<Offer)

The implication that Case 2 is a problem supports the conclusion of Wolak and Patrick (1997) that a uniform-price auction is more vulnerable to market power if large suppliers control both base-load and peaking units. More research is needed to identify conditions in a market which gives rise to indifference by suppliers about having marginal units dispatched. In particular, the effects of imposing hard limits on total available capacity in the market will be explored in future research. However, it is likely that this type of indifference poses a serious threat to the reliability of a power grid. Even though enough capacity to meet load may be offered at some price, very high prices tend to cause defaults on supply contracts and other subsequent disruptions. Equally important is the fact that customers will have to pay higher bills in the future if market power becomes established in new wholesale markets for electricity. It appears that this is already a serious problem in the PJM market

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