



The World's Largest Open Access Agricultural & Applied Economics Digital Library

This document is discoverable and free to researchers across the globe due to the work of AgEcon Search.

Help ensure our sustainability.

Give to AgEcon Search

AgEcon Search
<http://ageconsearch.umn.edu>
aesearch@umn.edu

*Papers downloaded from **AgEcon Search** may be used for non-commercial purposes and personal study only. No other use, including posting to another Internet site, is permitted without permission from the copyright owner (not AgEcon Search), or as allowed under the provisions of Fair Use, U.S. Copyright Act, Title 17 U.S.C.*

Strategic behaviour in the National Electricity Market

Donna Brennan and Jane Melanie
Australian Bureau of Agricultural and Resource Economics

41st Annual Conference of the Australian Agricultural and
Resource Economics Society
Gold Coast, Queensland, 22-24 January 1997

In the interests of promoting efficiency in the production and distribution of electricity the first phase of the National Electricity Market (NEM) is about to be introduced which will link generators and customers in New South Wales, Victoria and the ACT. One of the key design principles for the proposed National Electricity Code, which will underpin the operation of this new market, is to maximise the potential for competition between participants while maintaining system security. However, any perceived industry structure problems giving rise to market power of a generator is beyond the scope of the Code.

Market concentration and the size of demand relative to capacity jointly determine whether or not an individual market player faces a residual demand curve and is, thus, potentially able to influence the spot market price. The analysis undertaken in this paper suggests that large generation portfolios would be in a position to adopt non-competitive bidding behaviour, particularly in high demand periods. The modelling results indicate that such strategic behaviour has the potential to lead to significant increases in electricity prices relative to the base case. All generators in the NEM are estimated to benefit from strategic behaviour by major players in terms of higher operating surpluses.

This research has been supported financially by the Australian Competition and Consumer Commission. The focus of the paper is on the potential for non-competitive behaviour by generators in the National Electricity Market. It does not imply that the participating generators have adopted or would adopt any of the strategies referred to in the paper.

ABARE project 1465

ABARE

Innovation & Economic Research

GPO Box 1563 Canberra 2601 Australia
Telephone 06 272 2000 • Facsimile 06 272 2001
or visit our home page: <http://www.abare.gov.au>

Introduction

In the interests of promoting efficiency in the production and distribution of electricity the first phase of the National Electricity Market (NEM) is about to be introduced which will link generators and customers in New South Wales, Victoria and the ACT. In this new institutional setting, generators are required to submit dispatch offers, and market customers can also submit dispatch bids to a spot market. A central *dispatch process*, operated by the National Electricity Market Management Company Limited (NEMMCO), will aim to minimise the cost of satisfying *load* requirements based on dispatch offers by generators and subject to generation and network capacity constraints. It is designed to ensure spatially efficient spot prices, where spatial price differentials are no greater than the costs associated with electricity transmission.

However, given the cost structures of electricity generators and the limited number of market participants, non-competitive behaviour would have a significant impact on bidding strategies and the overall efficiency of the NEM. In particular, bidding above marginal cost may lead to significant distortions in the NEM both in terms of higher prices and restricted output. In this paper, the scope for strategic behaviour by large generators is assessed and the potential pricing and generator revenue outcomes resulting from such behaviour are quantified using an empirical model of the national electricity market developed by ABARE.

In section 2 of the paper an overview of the NEM in Australia is provided. This is followed by a discussion of the various non-competitive pricing strategies that might be observed in the market, taking into account the particular features of the Australian electricity market as well as the experiences from the UK electricity market reform. The empirical model is described in section 4 and followed by a discussion of the potential pricing and revenue outcomes of strategic behaviour in the NEM. In the conclusion the key results are summarised and possible solutions to any market distortions are identified.

2. Overview of the National Electricity Market

In parallel to reforms being undertaken in a wide range of countries, the Australian electricity supply industry is undergoing significant structural and regulatory reform. The National Electricity Code of Conduct sets out the market arrangements for the operation of

the NEM. An integral part of the proposed market design is the establishment of a spot market through which all electricity is traded. A brief overview of the operation of the spot market is provided below.

The spot market determines half hourly market clearing prices based on supply offers submitted by participating generators, and aggregate electricity demand for the trading period. All generators with a capacity of over 30 megawatts (MW) are required to put in offers for their output. On the demand side, eligible customers with electricity consumption level meeting the threshold criteria set by each participating jurisdiction, and who elect to participate in the spot market can bid for electricity. The spot prices, generator dispatch and customers *loads* are determined through a central *dispatch process*. Subject to system and other operating constraints, generators are dispatched in *merit order* with the lowest priced generator dispatched first to balance supply and demand. The marginal price band dispatched in a given trading period sets the market price for that period. Spot prices at different locations are adjusted for network constraints and losses. Even though all electricity traded must be dispatched through the pool, the Code does not constrain bilateral trading contracts outside the spot market arrangements. These contracts are financial instruments and do not guarantee physical delivery of electricity.

Although the broad objective of these proposed market design arrangements is to promote the creation of a competitive NEM, the industry structure emerging in participating states will also have important implications for the development of effective competition in the NEM. Market structure is beyond the scope of the Code and is more a matter for the individual jurisdictions to determine. State governments have thus embarked on the restructuring of their electricity supply industry along different lines and to varied time frames. To date reforms in participating jurisdictions have involved the:

- corporatisation of state electricity utilities;
- vertical separation of the generation function from the transmission and distribution activities in New South Wales, Victoria and South Australia;
- horizontal separation of generation in New South Wales and Victoria;
- gradual privatisation of generation and distribution assets in Victoria; and
- progressive introduction of competition at the retail end through the provision of supplier choice to *contestable* customers.

However, the provisions of the Code do not preclude individual generators from bidding behaviour designed to exploit any market power they might have.

3. Potential for non-competitive pricing in electricity markets

While much of the literature on oligopoly pricing concentrates on firms competing over either price or quantity, the bidding process in electricity spot markets is such that firms compete on both price and quantity, by placing bidding schedules to the central dispatch system. Klemperer and Meyer (1989) provide a theoretical analysis of oligopolistic competition over supply schedules, which focuses on single shot games where there is no scope for collusive behaviour. This work has been applied to the UK electricity market by Green and Newbery (1992). In their analysis, Green and Newbery assume that each firm submits a smooth supply function which is derived from its residual demand curve, where the residual demand curve includes the equilibrium bid function of the other supplier. Their result is a Cournot type solution where a smaller number of firms face steeper marginal revenue curves and therefore bid in steeper supply bidding schedules, resulting in more monopolistic outcomes.

von der Fehr and Harbord (1993) criticised the smoothness assumption and provide an alternative analysis of the more realistic market arrangement where each firm can submit a limited number of bid segments. In this case, a generator needs to take into account two opposing factors: the incentive to bid high and raise system marginal price; and the incentive to bid low and increase market share. They show that the importance of these opposing factors to an individual bidder depends on the bidder's probability of being the marginal bidder, which depends not only on marginal cost, but also on the size of demand and market share. For example, in the case of low demand where one firm can potentially supply the whole market, they predict Bertrand like behaviour where competition for market share keeps prices at marginal cost. For high demand scenarios, they examine a number of high-low bidding games where most firms bid low to ensure dispatch, while one firm bids the maximum admissible price based on its residual demand curve. von der Fehr and Harbord (1993) drew observations from the initial experience in the UK market to support their analysis. These observations are that firms changed from marginal cost bidding to strategic pricing behaviour with the onset of the high winter demand period.

The importance of capacity constraints in modelling pricing behaviour in electricity markets has also been highlighted by other authors. For example, Cowan and Vickers (1994) compare the ownership of generation capacity with demand in different months and different times of the day, to predict the likelihood of strategic pricing behaviour in alternative demand periods. However, despite the importance of market structure and

demand variability in determining the potential for market power, which implies that the potential for strategic pricing in a particular market is an empirical question, there have been very few empirical studies which model the characteristics of an actual electricity market.

One exception is the analysis of the south eastern Australian market conducted by London Economics and Hartord (1995). They examine the potential for market power in different day types (for example, winter vs summer, weekend vs weekday) and evaluate a range of high-low bidding strategies where the high bidders are assumed to place bids at multiples of marginal cost. Strategic players are not given the option of adjusting bids according to the size of their residual demand, which means that they are unable to bid low in off peak periods of the day in order to obtain market share. They cannot respond either to very high demand events (like cold spells, or generator break downs) by exploiting their larger residual demand. The result of this analysis was that in the year 2000 in New South Wales, there would be sufficient market power to expect non-competitive pricing in certain day types, even if the (then) monopoly was broken down into 3 portfolios of generating assets. In the present analysis, where strategic players are allowed to be more responsive to their residual demand curve, the results for New South Wales are even stronger, that is non-competitive pricing can be expected even with the current level of excess capacity in the system.

The importance of including flexibility in the bidding behaviour of the strategic player, particularly with regard to time of day pricing, can be demonstrated by comparing ownership of capacity and potential imports against the load duration curve. For example, in figure 1, typical load duration curves are shown for weekdays in winter and spring. The load duration curve shows the proportion of time in a day in which a *load* on the horizontal axis is exceeded. In this figure, the potential for Delta, a large portfolio of generating assets in New South Wales, to exercise market power is demonstrated, where it is assumed that rival firms bid in all their capacity at marginal cost. Also included in this comparison is the likely level of imports as derived from simulation runs of the model. It can be seen that there is scope for exercise of market power in peak periods of the day, and in winter months this market power may be extended to most hours of the day.

Figure 1 can be contrasted with figure 2 which shows the potential for the exercise of market power by Pacific Power, who owns the smallest share of thermal capacity in New South Wales. It can be seen that opportunities for strategic pricing are far more limited

when Pacific Power is the marginal bidder. These observations are reconfirmed in section 4 where the results of the analysis of gaming behaviour in New South Wales are presented.

Figure 1: Residual demand on weekdays in the NSW market: Delta

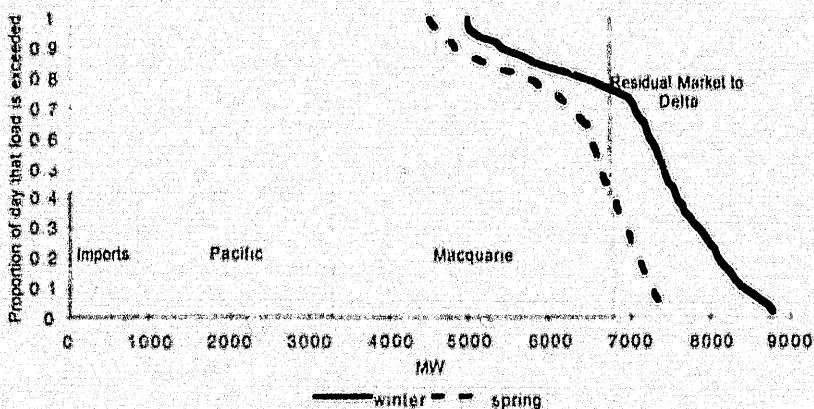
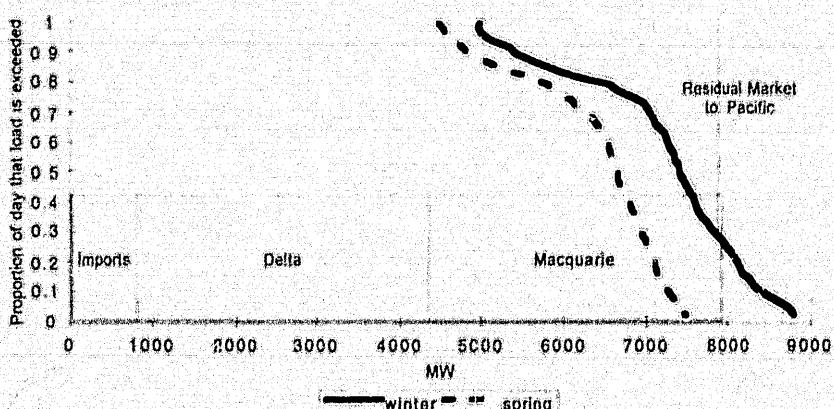


Figure 2: Residual demand on weekdays in the NSW market: Pacific Power



The potential for price manipulation depends not just on the existence of a residual demand curve, but also on its size. Thus, even though Delta may experience a residual demand curve for most of the day in winter, and for some of the day in lower demand months, whether or not it chooses to exploit this residual demand curve is an empirical question. By placing high bids, the strategic player sacrifices market share, and this will only be

preferred to low cost bidding if the gain in price justifies the loss in market share. In the following analysis, the revenue implications for a number of bidding games are compared to assess the likelihood of strategic behaviour in the NEM.

1. Ownership of thermal generation capacity in the NEM

Generators	Share of state's generating Capacity (%)
New South Wales	
Macquarie	37.5
Delta	38.5
Pacific Power	22
Victoria	
Loy Yang A	28
Loy Yang B	14
Hazelwood	23
Yallourn	21
Ecogen	7
South Australia	
SA Generation	100

The choice of strategic players was determined from an examination of market concentration in each state, which is shown in table 1. The potential for strategic behaviour in the South Australian market is obvious, because of the significant spatial monopoly faced by SA Generation. The *load* in South Australia always exceeds the amount of electricity that can be imported through the Victoria-South Australia interconnector (500 MW). Therefore, the residual demand faced by SA Generation is always significantly greater than zero. Most of the analysis of gaming behaviour focuses on alternative strategic players in the New South Wales market, where there is potential for a single bidder to face a residual demand curve at least for some of the time. The transmission line constraint between the Victorian and New South Wales market is rarely binding, so Victorian prices are strongly influenced by strategic behaviour in the New South Wales market. Since they have the lowest costs and are guaranteed of dispatch at marginal cost, they have the potential to free-ride on the strategic behaviour of the larger New South Wales portfolios and bid at marginal cost to maximise revenue. Consequently, in this paper the analysis centres on non-competitive behaviour in New South Wales and South Australia.

A range of bidding games are considered in which all but one bidder follows a marginal cost bidding strategy and the strategic player places bids according to the following rules. Assuming a linear demand with an intercept a and slope b , a set N of rival bidders with output $Q = \sum_N q_i$, the strategic player has a marginal cost c_j , capacity K_j and determines output q_j and price bids B_j according to whether they are in a low demand period or a high demand period.

1. *Low demand periods:* where $a - b(Q + 2 + \frac{\partial Q}{\partial q_j}) \leq c_j$

$$q_j = K_j; B_j = c_j$$

2. *High demand periods:* where $a - b(Q + 2 + \frac{\partial Q}{\partial q_j}) > c_j$

$$q_j = (a - bQ - c_j) / [(2 + \frac{\partial Q}{\partial q_j})b]; B_j = a - b(Q + q_j)$$

In a closed market with all other bidders bidding their entire capacity at marginal cost, then

$Q = \sum_K K_j$ and $\frac{\partial Q}{\partial q_j} = 0$. However there are a number of reasons why the conjectural

variations ($\frac{\partial Q}{\partial q_j}$) may be less than 0. First, in an open market, where imports are influenced

by both demand changes in the neighbouring market, and price changes in the local market, then the Cournot conjecture may not hold. Moreover, even in the South Australian market where all rival bids including imports are constrained by capacity, the Cournot conjecture indicates a static opportunity. Because of the potential limits to market power in a dynamic context, bidders may choose not to fully exploit the market power afforded to them even in the short term.

Potential limits to non-competitive behaviour in the NEM

A number of authors have argued that contracts will be effective in reducing market power in electricity markets (Helm and Powell 1992, Powell 1993, Lucas and Taylor 1993, Newbery 1995). For example, Lucas and Taylor (1993), and Helm and Powell (1992) have suggested that the existence of *vesting contracts* in the UK market was the reason behind the constrained bidding behaviour in the initial period following privatisation. Similarly, in their analysis of the South Australian market, Salerian, Robinson, Pearson

and Chan (1996) find that *vesting contracts* set on half of ETSA's generating capacity would reduce ETSA's market power substantially. Clearly, *vesting contracts* do limit market power because they represent a form of price regulation. However, it does not follow that bilateral *hedging contracts* in a free market will offer any insurance against strategic behaviour. Any generator who signs a contract to settle at a price below the expected spot market price would be expected to incur financial losses, so it should be expected that contract prices include any margin above marginal cost resulting from strategic behaviour in the spot market.

A more useful role for contracts may be to promote the contestability of the generation sector over the long term (Newbery 1995). Because of their high sunk costs and generally lower operating costs, existing generators can afford to operate at prices below potential entrants' marginal cost long enough to make entry unprofitable. Contracts allow potential entrants to lock in prices at the pre-entry (pre price war) level, and, therefore, encourages entry and limits strategic pricing behaviour to the entry inducing price. Newbery (1995) uses the UK experience to support his argument – the ability of independent power producers to enter into 15-year contracts with the distributors led to the entry of Combined Cycle Gas Turbine (CCGT) capacity amounting to around 15 per cent of total capacity by the end of 1994–95.

Another factor which impinges on the level of contestability in the NEM over the short to medium term is the lead time required for the construction of new power plants. For example, gas turbines take at least two years to be constructed (Electricity Supply Association of Australia 1991). Therefore, even if potential entry may provide a limit to competition in the medium term, there is potential for short term exploitation of the market by incumbents.

Another potential constraint on non-competitive behaviour is the threat of regulatory intervention. To the extent that high prices are expected to trigger the introduction of regulation, generators may adopt some form of limit pricing behaviour. In particular, it is apparent that some form of pricing regulation may be put in place in South Australia via a compliance program, so the potential for full exploitation of the spatial monopoly in South Australia may be limited.

Entry prices

The most likely type of technology to be considered by potential entrants in the NEM is the gas-fired generation and cogeneration. Reform of the gas industry, small and modular plant designs and shorter lead times, allowing for more marginal entry and lower risk associated with cost recovery, and the environmental advantage of natural gas all contribute to making gas fired generation a more attractive option for investors. The marginal operating cost of these units depends on the price of gas, with the cost of operating existing gas turbines ranging from around \$35 per MWh in South Australia. The feasibility of investment in gas turbines will depend on whether the costs of investment can be recovered through the excess of the average spot market price over marginal cost. The feasibility of entry at different levels of capacity utilisation is considered in table 2.

2. Average spot prices needed to justify investment

Marginal Operating Cost	\$ 35	\$ 55
Expected Dispatch (hours per day)	Average Spot Price (\$/MWh) a	
12	43	63
10	45	65
8	48	68
6	52	72
4	60	80
2	85	105
1	135	155

a This is the average price needed when the generator is dispatched

4. Quantifying the pricing and revenue implications of market power in the NEM

Model Description

The quantitative analysis was conducted using ABARE's model of the national electricity market. In this model, the spatial aspects of the electricity market are represented by 3 demand nodes (New South Wales, Victoria and South Australia) and 18 supply nodes from the three states and the Snowy Mountains Hydroelectric Scheme (SMHES). At each supply node, an individual plant is represented, and bids are made according to various bidding assumptions. The total quantity bid into the pool includes a stochastic component.

which represents random *forced outages* (for thermals) and random inflows of water into the Snowy Mountains Hydroelectric Scheme. The model has been developed using the Extend simulation software, and employs a modular approach to the construction of various components of the market described below:

Demand

State electricity *load* is represented by a load duration curve, with systematic variation (according to season) as well as random but serially correlated shifts on a daily basis. In the model runs discussed in this paper, three representative periods per day are chosen, in which the *load* associated with 17, 50 and 83 per cent probabilities on the load duration curve are used to represent peak, shoulder and base loads respectively. An example of the *loads* predicted by the statistical model is shown in figure 1 in the appendix.

This information is used to derive a series of shifting demand curves for different times of the day. At each demand node, bids are made by a representative customer which show the prices at which the customer is willing to reduce or increase *load*. Demand elasticity of -0.25 evaluated at the median *load* on a typical weekday is used for the analysis presented in this paper. The sensitivity of the results to the demand elasticity assumption has been tested under a range of elasticities (-0.1 to -0.5). Changing the demand elasticity does not alter the relativities but only affect the magnitude of the results.

Thermal Generators

Base thermal plants are the slow start thermals, and include brown coal, black coal and gas steam plants. In the model, there are 15 base thermal plants, representing the major thermal generators in New South Wales, Victoria and South Australia. Marginal cost assumptions for each plant were based on assumed fuel and operating and maintenance costs. These assumptions are shown in table A1. The inflexibility of slow start thermal plants is modelled by assuming that the minimum capacity of each operating unit is bid in as *self-dispatch*. In the Code, *self-dispatch* is offered at a negative price, which is the price that generators are willing to pay to avoid the high costs involved in reducing *load* below the minimum *load* in cases of excess generation. Generally, the generator receives some positive spot market price for its *self-dispatch* output, and in the model it is assumed that the generator will shut down a unit if the average price received is below its avoidable cost by an amount greater than the cost of shutting down a unit. Competitive bidders are assumed to bid the remainder of their dispatchable output at marginal cost. At each step in

the simulation, the quantity offered by competitive generators can vary due to random outages and planned shut downs.

Bids by operators of peak thermal plants are assumed to be competitive in the cases of Victoria and New South Wales. The assumptions used to represent the costs and capacity of gas turbines in each state are shown in table A1.

Strategic bidding behaviour by thermal generators

As discussed in the previous section, bidding behaviour is conditional on the expectation that a strategic player will face a residual demand. In each step of the simulation, the strategic player assesses its likely level of residual demand, which is determined by forecast load, and expected supply by rivals in their local market (including net trade). These expectations are based on the most recent observation for a similar demand period, which is likely to be a good predictor of current period rival dispatch, due to the serial correlation in load and in plant availability. In cases where strategic bidders expect to face a residual demand, they are assumed to determine price and output decisions based on this residual demand curve.

The Snowy Mountains Hydro Electric Authority (SMHEA)

The amount of power available at any point in time is determined from a detailed hydrological model that is described in detail in Seccimarro, Beare and Brennan (1997). This model distinguishes between the amount of river run power available, and the amount that can be stored for future use. River run power is bid at \$0/MWh, as it has no opportunity cost. It is assumed that the SMHEA bids for its non-river run power based on a residual demand curve which is aggregated across the different regions. Residual demand is assumed to be based on Cournot conjectures about supply by the other bidders. In order to ration the scarce hydro-electric capacity over the year, a shadow cost on current releases is used when determining strategic bids. This shadow cost is determined iteratively such that dispatch equals average annual output (5100GWh) over the year.

The Dispatch Process

At each step of the simulation, the bidding information is passed to a linear programming model which determines the least cost dispatch taking account of inter-regional transmission constraints and losses. This dispatch algorithm is based on the dispatch algorithm described in the National Electricity Code of Conduct. Prices at state demand nodes are determined

from the dual solution, and this information is used to calculate revenue for each portfolio, as well as shut down decisions for thermal plants.

Results

The base case

The benchmark used in this analysis is the case when all thermal generators are assumed to make bids at marginal cost, and the SMHEA is assumed to be the residual bidder. (In the base case year of 1996, there was limited residual demand after all available thermal plants' capacity were bid in at marginal cost.) Average prices under this scenario are summarised in table 3.

3. Base case - simulated annual average of spot market prices in 1996

	Peak \$/MWh	Median \$/MWh	Off Peak \$/MWh
New South Wales	25.62	22.90	21.39
Victoria	29.73	25.08	20.88
South Australia	30.43	26.24	22.01
Snowy	27.71	23.94	20.68

Spot market prices in the base case is effectively a reflection of the marginal costs in each state and also of the direction of interstate trade. (Marginal bid curves for the base case are illustrated in figures 2a to 2c in the appendix.) In off peak periods, Victoria exports to New South Wales because the very low cost brown coal plants are not fully dispatched locally. In these periods, the spot price in Victoria is determined by the price in its export market. However, brown coal plants are not sufficient to meet peak *load* in Victoria, and it is often trade from New South Wales and the SMHEA rather than local high cost gas plants that are used to meet the Victorian peak demand. Most trade between South Australia and Victoria flows into South Australia because generators in South Australia have relatively higher marginal cost than generators in Victoria.

Strategic behaviour

In the following analysis, the strategies of large players are examined and the output and pricing decisions that are likely to result from the current market structure in the NEM are quantified. A range of conjectural variations were used to test for varying degrees of market

power by strategic players. In one set of scenarios it was assumed that each strategic player exerts full market power over its residual demand curve (ie the conjectural variation coefficient was set to 0). These assumptions led to very high prices with the average peak regional prices ranging from \$78 to \$94 per MWh when both SA Generation and Delta are strategic players. Such pricing strategies are unlikely to be sustainable due to the joint threats of entry and of regulatory intervention. Consequently, alternative scenarios were considered in which lower levels of market power were exercised by reducing the conjectural variation coefficient. The conjectural variations assumed for each strategic player for the results presented in this paper are provided in brackets. The scenarios used to test for the exercise of market power arising from the structure of the NEM are:

- all generators in Victoria and New South Wales forced to bid competitively (at marginal cost), and SA Generation bidding strategically (-0.95);
- Delta and SA Generation bidding strategically and all remaining thermal generators in New South Wales and Victoria bidding at marginal cost (0, -0.95);
- Macquarie and SA Generation bidding strategically, and all remaining thermal generators in New South Wales and Victoria bidding at marginal cost (0, -0.95);
- Pacific Power and SA Generation bidding strategically and all remaining thermal generators in New South Wales and Victoria bidding at marginal cost (0, -0.95); and
- Delta, Macquarie and SA Generation bidding strategically, and all remaining thermal generators in New South Wales and Victoria bidding at marginal cost (-0.8, -0.8, -0.95).

The pricing outcomes for each strategic combination for the various regional markets are shown in table 4. These results suggest that spot market prices in all participating regions are increased as a result of strategic behaviour in South Australia and New South Wales. High bidding by SA Generation leads both peak and off-peak prices in South Australia to increase by over 35 per cent. This is due to the high level of market concentration in South Australia. Even with maximum imports, SA Generation can supply half of the market in off peak periods. The degree of spatial monopoly held by SA Generation is illustrated by the large differences between prices in the South Australian and other markets. Strategic behaviour by SA Generation is also estimated to have significant flow through effects into both the New South Wales and Victorian markets. To a large extent, this can be attributed to interstate trade effects; high price bids in South Australia leads to an increase in imports into South Australia particularly from Victoria, which in turn implies that higher cost generators in Victoria need to be dispatched to satisfy local demand.

4. Strategic bidding - simulated annual average of spot market prices in 1996

Peak Regional Prices

Strategic Player(s)	New South	Victoria	South
	Wales	\$/MWh	Australia
Base case	25.26	29.73	30.43
SA Generation	28.95	35.42	41.16
SA Generation, Pacific Power	32.98	37.27	43.45
SA Generation, Delta	58.30	56.21	58.04
SA Generation, Macquarie	54.77	53.03	55.21
SA Generation, Delta & Macquarie	64.00	60.00	60.73

Off Peak Regional Prices

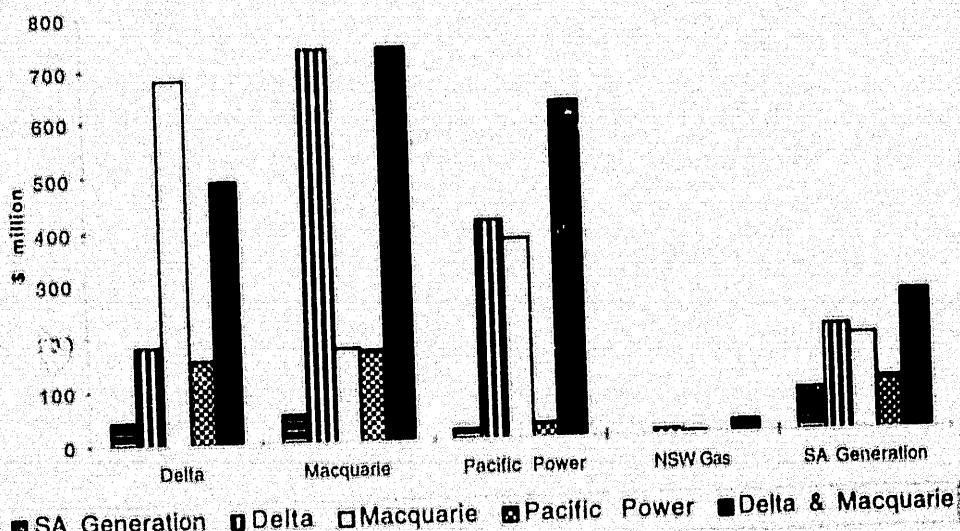
Base case	21.39	20.88	22.01
SA Generation	21.92	22.51	30.56
SA Generation, Pacific Power	21.93	22.10	30.43
SA Generation, Delta	26.24	25.78	32.83
SA Generation, Macquarie	25.49	25.29	32.44
SA Generation, Delta & Macquarie	39.91	36.17	40.75

The analysis of strategic behaviour in New South Wales suggests that Pacific Power would have much less impact on prices than either Delta or Macquarie if it were to act as the strategic player. This reflects the relatively lower share of generation capacity owned by this portfolio. Because of the high level of excess capacity in the system Pacific Power has very limited residual demand for most of the time. The impact of alternative price leaders on operating surplus of generators in New South Wales and South Australia is illustrated in figure 3.

When the single strategic player scenarios are compared, it is clear that each player would prefer not to be the high bidder, provided that someone else performs this role. In particular, Macquarie would have the highest revenues if it were to bid competitively and Delta were to bid strategically. Similarly, Delta would achieve the highest operating surplus if it were to bid at marginal cost and Macquarie were to bid strategically. This suggests that

there is likely to be a dominant pure strategy to this game, where both Delta and Macquarie would be in a position to act as strategic players jointly. As shown in figure 3, strategic bidding by each player has the highest payoff regardless of the action of the rival bidder. While both would prefer that the other sets the price, they would also both prefer to be the price setter rather than bear the risk that neither would set the price. The revenues achieved by jointly setting the price indicate that even in a non-collusive game, strategic behaviour by both players would have high payoffs.

Figure 3: The simulated impact of alternative strategic players in New South Wales on operating surplus



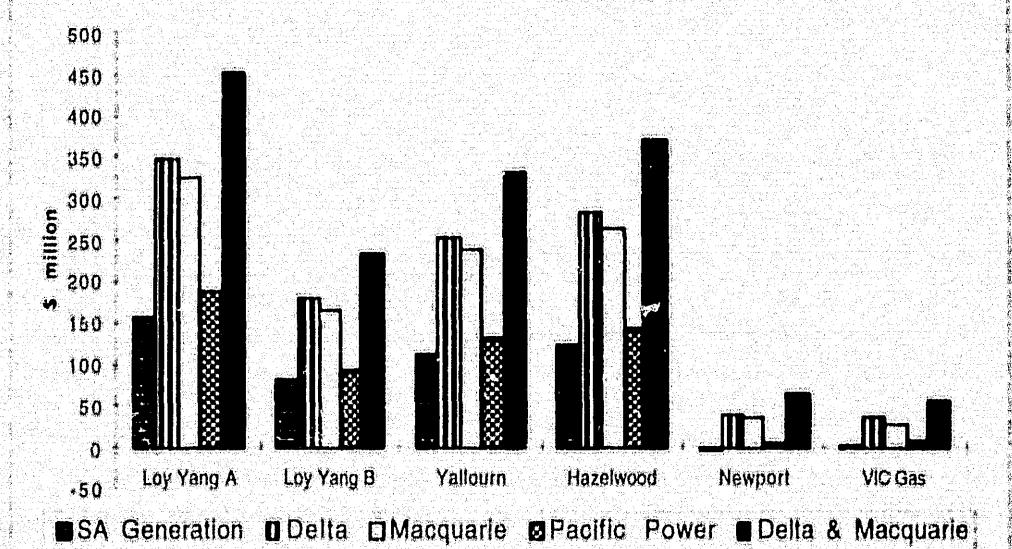
Impact of strategic behaviour in New South Wales on Victorian generators

In all cases, the Victorian generators would benefit from strategic behaviour in the New South Wales market (figure 4). As the Victorian generators are the lowest cost suppliers and are always dispatched, given marginal cost bidding, the effects of strategic behaviour in New South Wales are essentially price effects.

Trade between the two states in off-peak periods is just as likely to flow from New South Wales to Victoria as from Victoria to New South Wales, compared to the base case where off-peak trade flowed mainly in the Victoria to New South Wales direction. Two factors contribute to this outcome: first, strategic bidding by SA Generation in South Australia

leads to a higher level of trade from Victoria to South Australia in off peak periods, and second, exports from the SMHEA in off-peak periods are reduced substantially.

Figure 4: The simulated impact of alternative strategic players in New South Wales on operating surplus of Victorian generators



5. Conclusions

One of the key design principles for the proposed National Electricity Code is to maximise the potential for competition between participants while maintaining system security. However, any perceived industry structure problems giving rise to market power of a generator is outside the scope of the Code.

Even though major restructuring has already occurred in Victoria and New South Wales, the current structure of the NEM is characterised by a significant degree of market concentration particularly in South Australia and New South Wales. Market concentration and the size of demand relative to capacity jointly determine whether or not an individual market player faces a residual demand curve and is, thus, potentially able to influence the spot market price. Entry of new independent generators can be an effective way of limiting the market power exerted by a generator portfolio. However, the threat of entry to

incumbent generators is likely to be more effective in the longer run, and if new investors can secure contracts with customers. In the short to medium term, large generator portfolios in New South Wales and South Australia are likely to have sufficient market power to dominate particular market segments.

The results of the modelling undertaken in this paper suggest that strategic bidding behaviour by SA Generation in South Australia and the two largest generator portfolios in New South Wales has the potential to lead to significant increases in electricity prices relative to the base case. All generators in the NEM are estimated to benefit from strategic behaviour by major players in terms of higher operating surpluses. With generation costs accounting for over two thirds of total delivered costs to electricity consumers, such strategic behaviour by generators would have important implications for the costs to consumers.

Regulation can provide a check to the exercise of market power. However, this option is not without costs. Alternatively, further structural reform may remove the need for regulatory intervention. This option needs to be carefully balanced against the need to ensure the financial viability of the generation sector. In the longer term, new entry, the construction of new interconnectors and the augmentation of existing ones could enhance competition and, hence, reduce the scope for strategic behaviour in the NEM.

References

- Armstrong, M., Cowan, S. and Vickers, J. 1994, *Regulatory Reform: Economic Analysis and British Experience*, chapter 9, MIT Press, Cambridge, Massachusetts.
- Electricity Supply Association of Australia (ESAA) 1991, *Gas for Electricity Generation*, Sydney.
- 1996, *Electricity Australia 1996*, Sydney.
- Green, R. and Newbery, D. 1992, 'Competition in the British electricity spot market', *Journal of Political Economy*, vol. 100, no. 5, pp. 929-53.

- Helm, D. and Powell, A. 1992, 'Pool prices, contracts and regulation in the British electricity supply industry', *Fiscal Studies*, vol. 13, pp. 89-105.
- Klemperer, P. and Meyer, M. 1989, 'Supply function equilibria in oligopoly under uncertainty' *Econometrica*, vol 57, no. 6, pp. 1243-77.
- London Economics 1994, *Review of the NGMC National Market Trial*, a report to the Department of Primary Industries and Energy, July, Melbourne.
- London Economics and D. Harbord and Associates 1995, *Market Power in the Australian Electricity Market*, a report to the Industry Commission, August, Melbourne.
- Lucas, N. and Taylor, P. 1993, 'Characterizing generator behaviour: bidding strategies in the pool', *Utilities policy*, April, pp. 129-35.
- Newbery, D. 1995, 'Power markets and market power', *Energy Journal*, vol. 16, no. 3, pp. 39-66.
- Powell, A. 1993, 'Trading forward in an imperfect market: the case of electricity in Britain', *Economic Journal*, vol. 103, pp. 444-53.
- Salerian, J., Robinson, J., Pearson, K. and Chan, C. 1996, Applying spatial-temporal programming models to study the potential for market power in the National Electricity Market, Paper presented at the 25th Conference of Economists, Australian National University, Canberra, 22-26 September.
- Scoccimarro, M., Beare, S. and Brennan, D. 1997, 'The potential impacts of changing operations in the Snowy Mountains Scheme', ABARE paper to be presented at the 41st Annual Conference of the Australian Agricultural and Resource Economics Society, University of Queensland, 22-24 January. (forthcoming)
- von der Fehr, N and Harbord, D. 1993, 'Spot market competition in the UK electricity industry', *Economic Journal*, vol. 103, May, pp. 531-46.

Appendix

A1. Power Station Assumptions

Power Stations	Units	Unit	Fuel	O&M		Capital	Planned Outage	Forced Outage	Off-loading	
				Minimum Capacity	Maximum Capacity					
				MW	MW					
New South Wales										
Bayswater	4	275	634	13	7.8	1	10	5.7	-5	
Liddell	4	227	480	14.7	7.8	1	10	5.7	-6	
Vales Point	2	286	635	14.8	7.8	1	10	5.7	-6	
Munmorah	4	110	287	14.3	7.8	1	10	5.7	+5	
Mount Piper	2	250	634	12.2	7.8	1	10	5.7	-6	
Wallerawang	2	205	445	14.8	7.8	1	10	5.7	-5	
Eraring	4	176	635	14.3	7.8	1	10	5.7	-6	
NSW Gas	12	0	25	50	5	0.40	6	10	0	
Victoria										
Loy Yang A	4	400	460	7	8.2	1	12	5.9	-8	
Loy Yang B	2	400	460	7	8.2	1	12	3.6	-8	
Hazelwood	8	175	185	7.7	8.2	1	12	5.9	-7	
Yallourn	4	290	335	7.5	8.2	1	12	5.9	-7	
Newport	1	200	463	22.5	8.2	0.94	12	5.9	-5	
VIC Gas	7	0	65	35	5	0.40	6	10	0	
South Australia										
Northern	2	185	230	13.2	7.1	1	14	3.1	-5	
Torrens Island A	3	60	116	19	7.1	0.94	14	3.1	-6	
Torrens Island B	4	60	191	18	7.1	0.94	14	3.1	-5	
SA Gas	7	0	45	30	5	0.40	10	10	0	

Sources: London Economics (1994), London Economics and Harbord (1995), ESAA (1991), ESAA (1996).

Figure 1: Simulated load forecasts, Victoria

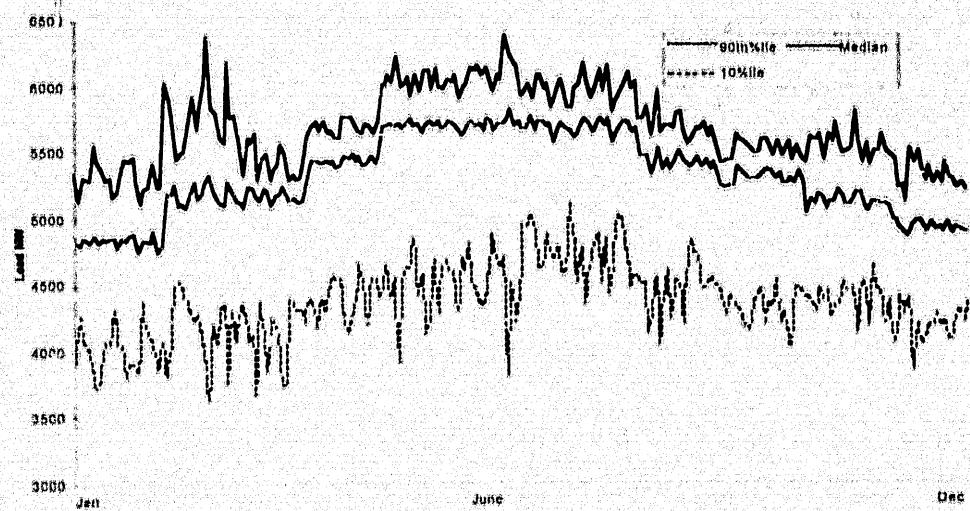


Figure 2a: Marginal competitive bid curve and mean local load, New South Wales

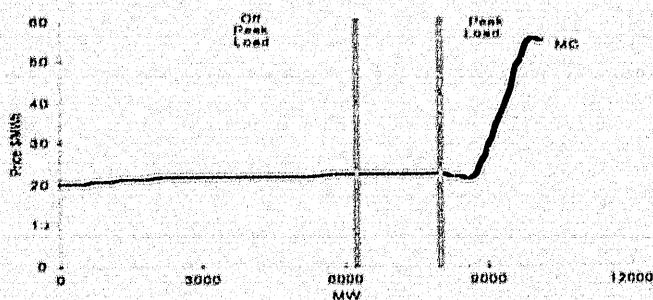


Figure 2b: Marginal competitive bid curve and mean local load, Victoria

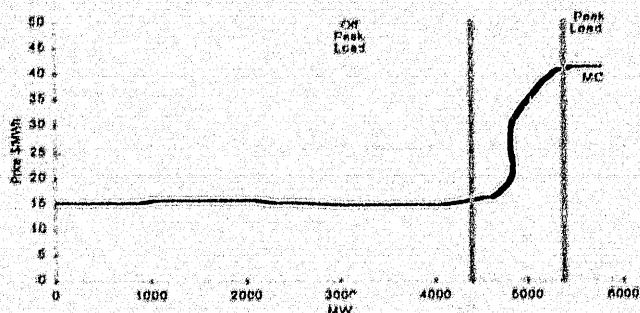
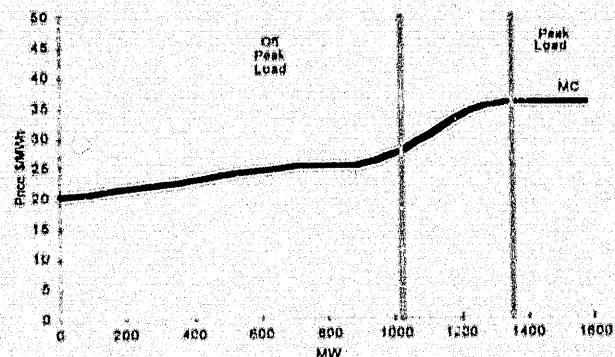


Figure 2C: Marginal competitive bid curve and mean local load, South Australia



Glossary

Contestable customers:	Eligible customers who elect not to be a market participant (that is a person who trades in the wholesale market) but to purchase electricity from a market participant other than their local participant retailer.
Dispatch process:	The process of bringing individual generators into production.
Forced outage:	The unscheduled stoppage of an electricity generating unit.
Hedging contracts:	A voluntary contract affording protection to one or more parties against fluctuations in spot market prices.
Load:	Electricity demand.
Merit order:	The ranking of generating units in order of their increasing costs of generating electricity.
Off-loading price:	The price specified for a price band and a trading interval in a dispatch offer for the off-loading of a generating unit below its self-dispatch level.
Planned outage:	The planned removal of a generating unit from service for routine or preventative maintenance.
Self-dispatch:	The level of generation as specified in a dispatch offer and a trading interval, which is the level at which that generating unit must be dispatched by NEMMCO unless it is required to operate under a direction issued by NEMMCO in cases of excess generation.
Vesting contracts:	Involuntary contracts used as instruments of regulation imposed on generators.