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# Measuring market power in electricity generation: A long-term perspective using a programming model

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**Abstract**

This paper focuses on measuring the extent to which market power has been exercised in a recently deregulated electricity generation sector. Our study emphasises the need to consider the concept of market power in a long-run dynamic context. A market power index is constructed focusing on differences between actual market returns and long-run competitive returns, estimated using a programming model devised by the authors. The market power implications of hedge contracts are briefly considered. The state of Queensland Australia is used as a context for the analysis. The results suggest that generators have exercised significant market power since deregulation.


*JEL classification:* L94; C61; D43

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## 1. Introduction

There has been considerable discussion about market power in recently deregulated electricity generation markets, for example in the UK, Australia, Latin America,

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Scandinavia, and some jurisdictions in North America, such as California. However, further work is required on measuring the extent to which market power shapes market outcomes. In contrast to much of the literature on electricity reform and market power issues, this paper adopts a long-run approach to the measurement of market power using the electricity generation sector in Queensland Australia as a context. While Queensland is part of Australia's National Electricity Market (NEM),[1] the region has been prorogued until recently and even now the capacity of the interconnection with the adjoining states is limited relative to Queensland's demand for electricity. The Queensland Electricity Industry (QEI) supplies electricity to about 60% of the State's 1.726 million square kilometre area. As of December 2002, annual electricity sales were of the order of 40,000 GWh to some 1.5 million customers, with a peak coincident demand near 7000 MW and total generation capacity of the order of 9000 MW, with an additional import capacity of up to only 500 MW (Powerlink, 2002).

This paper consists of five sections, including this introduction. Section 2 considers the concept of market power and its sources, and also discusses some specific issues concerning market power in electricity generation. Among other matters, the discussion emphasises the need to consider the concept of market power in a long-run dynamic context. Section 3 reviews the approaches adopted by various researchers to analyse market power in electricity industries, including California. Section 4 analyses the extent to which market power has been exercised in electricity generation in Queensland. Two methods are used to obtain estimates of long-run marginal costs of electricity supply under competitive conditions. These methods provide consistent results. A market power index is then constructed and focuses on differences between actual market returns and competitive (marginal cost) prices. The market power implications of hedge contracts are also considered. Finally, Section 5 provides this paper's conclusions.

## 2. Market power in electricity generation

### *2.1. Market power: basic concepts*

In broad terms, a firm has market power if it is able to raise price above marginal cost without experiencing a significant decline in demand. Put another way, a firm possesses market power if it is able to increase its profitability by raising price above marginal cost.

A review of the economics and strategic management literature highlights a number of factors that determine the significance of market power in industry. Factors noted include the number of firms in the industry; industry demand elasticity (short-run and long-run elasticity); product differentiation and the availability of substitutes; the interaction of

[1] Since December 1998 the NEM includes South Australia, Victoria, New South Wales (NSW), the Australian Capital Territory, and Queensland. It is managed by NEMMCO which was established to administer the recently deregulated electricity markets to achieve competitive price outcomes. In each time period generator bids are 'stacked' and a programming model is used to match demand with generation at Regional Reference Nodes (RRNs) at Regional Reference Prices (RRPs). As at December 2002, Queensland had one RRN, called QLD1. For further details see NEMMCO (2002) and Powerlink (2002).

firms in the industry; and the significance of entry barriers. The need to consider the concept of market power in a long-run dynamic context is also highlighted. These points are captured in the following extracts from Church and Ware (2000) with reference to US anti-trust case law.

> In economics market power is defined as the ability to profitably raise price above marginal cost. Any firm with a downward-sloping demand curve will have market power. However, not all market power warrants antitrust concern. *Antitrust enforcement is warranted if market power is significant and durable* (our emphasis). Significant means that prices exceed not only marginal cost, but [also] long-run average cost so that a firm makes economic profits. Durable means that the firm is able to sustain its economic profits in the long-run.

The criteria for 'significance' correspond to the definition of monopoly power by the US Supreme Court. According to the Court '… monopoly power is the power to control prices or exclude competition'. Church and Ware comment:

> While the use of 'or' has caused some confusion, the consensus is that monopoly power consists of market power (the power to control prices) and sustained monopoly profits (from the power to exclude competitors). *In the long-run it is the power to exclude competitors that provides the firm with market power*" (p. 603).

It is also important to note that the economic concept of market power as defined above finds similar, if not identical, expression in Australian Trade Practices case law. Brunt (1994) states:

> …there is no doubt that the Trade Practices Act is economic law, though the characterization was not fully recognized until February 1989.

This was the year that the High Court of Australia brought down its judgment in *Queensland Wire Industries Pty. Ltd. vs. Broken Hill Pty. Co. Ltd.* (1989) CLR 177; 83 ALR 577. Since that judgment the lower Courts in considering market conduct and market power issues give consideration to a number of economic factors. These include the issue of market definition, the nature and significance of barriers to entry; the link between barriers to entry and the potential to exercise *substantial* market power and anti-competitive conduct and the ability of a firm to raise price above costs of supply (where costs of supply is defined as the minimum costs an efficient firm would incur in providing the good or service), without loss of customers to rivals 'in due time'. The importance of the time or '*durability*' element to the issue of whether the exercise of monopoly power warrants judicial action was noted, for example, by Dawson, J. in the QWI case cited above. Dawson, J. quoted with approval the definition of market power provided by Kaysen and Turner:

> A firm possesses market power when it can behave *persistently* in a manner different from the behaviour that a competitive market would enforce on a firm facing

otherwise similar cost and demand conditions (Kaysen and Turner, 1959, p. 75, our emphasis).

However, it is important to note that while the Australian Courts consider the above *long-run concepts* in their deliberations on market power issues, especially under Section 46 of the Trade Practices Act 1974, these concepts have not been tested in the context of the recently deregulated and restructured electricity generation sector.

### *2.2. Electricity generation*

There are a number of potential sources of market power in the deregulated and restructured electricity generation sector. These are discussed as follows:

- *Market share*: In most countries restructuring of generation has resulted in an oligopolistic generation sector, i.e., the generation market is dominated by a few large generation companies running a portfolio of plant types, sizes, and fuel sources. In this situation there is potential for generators to engage in gaming strategies for the purpose of achieving above normal returns on capital. In Queensland electricity generation has been dominated since the commencement of the market by four government-owned corporations[2] who control more than 80% of Queensland's generation capacity. The ability of generators to manipulate market prices depends, among other things, on the conditions of entry including the opportunities for generators in other States (e.g., NSW) to compete in the Queensland market. As we have seen, even with the commissioning of the Queensland–NSW Interconnector (QNI) in February 2001, residual demand in Queensland remains high. Pricing strategies, which might reflect the exercise of market power, include rebidding strategies (NECA, 2001a,b).
- *Capital requirements and economies of scale*: The existence of large capital requirements (large fixed, sunk costs) for the construction of base load plant may constitute a barrier to entry for potential competitors. An important consideration concerns both the time it takes for potential entrants to raise capital and the extent of demand growth. Large capital requirements are usually associated with plant that exhibits economies of scale. For base load plant efficient entry requires that demand growth be sufficient to accommodate additional large capacity or (given demand) that the potential entrants have access to lower cost resources or plant technology. Capital requirements and economies of scale, together with the fact that investment in generation is a sunk cost, may allow incumbent generators to exercise market power (and thus earn above competitive returns on capital) without attracting new entry.
- *Strategic behaviour*: Incumbent generators may engage in entry deterrence strategies such as building excess generation capacity in conjunction with the mothballing of older higher cost plant. In other words, incumbent generators might prevent new entry by making credible threats to create excess capacity. On this point it is interesting to note that the incumbent generators in Queensland have added significantly to capacity

[2] CS Energy, Stanwell Corporation, Tarong Energy, and Enertrade. For further details see Powerlink (2002).

and mothballed some older plant since the commencement of deregulation and structural reform of the QEI (see NEMMCO, 2001b, Powerlink, 2002).

- *Environmental issues*: There may be regulatory barriers such as environmental requirements that have to be met by new entrants. This can result in lengthy time delays and provide incumbent generators with opportunities to earn above normal returns on capital.
- *Co-incident demand peaks*: Since the demand for electricity varies on a temporal basis an important issue concerns the extent to which market power can be exercised at different periods of time. This requires consideration of available capacity and the demand requirements at different time periods. Peak demand periods would seem to offer the greatest potential for the exercise of market power, especially if potential competitors, say in other interconnected jurisdictions, have little if any spare capacity available during the same time periods.
- *Availability of substitutes*: Discussion of the relationship between barriers to entry and the exercise of market power by incumbent firms also requires discussion of the availability of close substitutes. As mentioned earlier competition may be from suppliers of identical products, such as electricity or from suppliers of alternative sources of energy such as gas. Accordingly, the exercise of market power requires definition of the relevant market and thus the availability of competitive substitutes on the demand or supply side. If, for example, incumbent electricity generators are able to exercise market power in the short-run their ability to do so in the long-run is influenced not only by the importance of barriers to entry on the supply side (i.e., barriers to competition from new electricity generators), but also by alternative products available to customers, especially gas. However, in the Queensland context (and the NEM generally) the long-run price elasticity of demand has been estimated to be quite low (NEMMCO, 2001b, pp. 3–27).

Given that an efficient generation system will usually contain a mix of plant types and that demand varies by time of day, the industry short-run marginal cost curve is typically upward sloping. If the short-run industry marginal cost exhibits a step like function (as is usually thought to be the case) then price may be equal to or greater than marginal costs even in a competitive price-taking situation. This means that, in the words of Borenstein et al. (2000, p. 5)

> *...in the absence of market power by any seller in the market, price may still exceed the marginal production costs of all facilities producing output in the market at that time*. Price above marginal production cost of all operating plants is not in itself proof of market power. However, *offering* power at a price significantly above marginal production (or opportunity) cost, or failing to generate power that has a production cost below the market price, is an indication of the exercise of market power.

In *analysing* market power, it is therefore important to distinguish between the short-run and long-run. If above normal returns are earned under competitive conditions in the short-run this would provide an incentive for additional investment in generation capacity by existing generators and/or by new entrants. This long-run adjustment would lead to long-run competitive returns on capital. In contrast, if market power is exercised and is durable and significant this implies that above normal returns can be earned in the long-run and that industry investment (new capacity created in the long-run) will differ in quantity and plant mix to what would occur under competitive conditions.

## 3. Measuring market power in restructured and deregulated electricity markets

There are a number of economic studies of market power issues in restructured and deregulated electricity generation markets in various countries. The early work in this area focused on the UK but has extended to other countries. This includes Australia, Latin America, Scandinavia, and some jurisdictions in North America, such as California, where the traditional utility industry model of the vertically integrated regulated regional monopoly 'utility' has also been replaced by vertical disaggregation and horizontal restructuring of the generation sector into oligopoly market structures together with the removal of legal barriers to entry.

The economic rationale for horizontal restructuring and deregulation of the generation sector is that generation is thought to be potentially competitive and that competition among generators would lead to productivity improvements and lower per unit costs by profit maximizing generator firms. Competition would also lead to electricity prices being closely aligned to costs of supply both in terms of time of production and by location. It was also assumed that competition would lead to dynamic efficiency in the sense that a competitive market in generation will result in efficient choice of generation technology and timing and location of investment decisions as demand for electricity grows. Under an efficient market system this would be coordinated with investment in transmission capacity, and result in least cost expansion and optimisation of benefits to final customers.

Some early concerns in the UK that the two largest generators, National Power and PowerGen, were manipulating pool prices by withholding capacity during peak demand periods, while attracting the attention of the then UK Electricity Regulator, OFFER (Office of Electricity Regulation) also gave rise to a number of studies of the operation of the oligopoly electricity generation market, especially modelling of the electricity pool. One objective of these studies was to determine whether under the new market arrangements, of an electricity pool and contracts between generators and retailers, the generators were able to exercise market power. Some of the modelling of generator strategies is essentially theoretical and some empirical—the latter being concerned mainly with the issue of the gap between price and marginal costs.

The models adopted by researchers such as Green and Newbery (1992), Newbery (1998), and Wolfram (1998, 1999) are oligopoly models which simulate the operation of electricity markets and from which inferences about firm behaviour are drawn. Because electricity generators provide a homogeneous product, the Cournot assumption that firms make strategic decisions by quantity-setting behaviour is considered by various researchers to be a better approximation to reality than price-setting behaviour. Borenstein et al. (2000) observe:

> Because of the electricity industry's long history of regulation, there is little existing work that attempts to estimate the competitiveness of an electricity market

> based upon actual observed outcomes. Most of the work to date has instead relied upon market simulations that are based upon some form of oligopoly equilibrium. Green and Newbery (1992), apply the supply function equilibrium concept to the electricity market in England and Wales, while Schmalensee and Golub (1985) and Borenstein and Bushnell (1999), utilize the Cournot equilibrium assumption to simulate market outcomes for the continental U.S. and California markets, respectively. Borenstein et al. (1998), and Cardell et al. (1997) all utilize the Cournot assumption to analyze the impact of binding transmission constraints on strategic competition in the electricity industry (pp. 2–3).

Recent empirical research that attempts to estimate actual levels of market power rather than the potential for market power in the electricity generation sector includes Wolfram (1998, 1999), Wolak and Patrick (1997), Wolak (2000), and Borenstein et al. (2000).

Studies of the UK electricity market such as those by Green (1994) and Von der Fehr and Harbord (1993) compare generators' bid prices to their estimated costs on various representative days. Wolak and Patrick (1997) examine the rules governing the spot market in the UK and show how the rules provide the generators with an incentive to withhold capacity during certain half-hour periods for the purpose of pushing up the pool price. Wolfram (1999) also estimates price–cost mark-ups for UK generators, using public domain data and an approach to cost estimation similar to other researchers (such as used by Green and von der Fehr and Harbord). Wolfram also employs two approaches to measuring price–cost markups that ignore information on marginal costs. There are also research papers by Green (1999) and Newbery (1998) that analyse market behaviour by investigating the operation of both spot and contract markets. Much of this work is theoretical with some empirical content.

There is also some research in the Australian context that draws on aspects of the work referred to here. Wolak (2000) derives a theoretical model "... of bidding behavior in a competitive market which incorporates the impact of the electricity generator's position in the hedge contract market on its expected profit-maximizing bidding behavior" (p. 3) and applies this to bid and contract data for the first 3 months of the operation of the National Electricity Market (Mark 1). ABARE (2002), Brennan and Melanie (1998) also make use of overseas research to examine the potential for non-competitive pricing in the new South-Eastern Australian electricity market.

In those studies concerned with estimating actual market performance as distinct from predicting market outcomes, price and short-run marginal cost data (or estimates of marginal costs) have been used to generate price-cost markups or Lerner Indices of the form.

$$L = (p - (\mathrm{mc})q)/p = 1/e \tag{1}$$

Broadly, in the modelling of oligopolistic electricity markets $p$ is market price, $\mathrm{mc}(q)$ is a firm's marginal cost at output $q$, and $e$ is the absolute value of the elasticity of market demand. Ratios of profit margin ($p-\mathrm{mc}$) and price are compared with outcomes expected under various market conditions, for example, the closer the ratio is to zero the more competitive the market; conversely the closer the ratio is to unity the greater the degree of monopoly power exercised.[3] However, data are rarely available for marginal costs and price–cost margins. As noted in the literature price–cost margins are frequently measured as ($P$−AVC)/$P$, where $P$ is a measure of price and AVC is a measure of average variable costs.

Borenstein et al. (2000) provide an index of market performance (or *market power*) for the California electricity market, which is conceptually similar to a Lerner Index. Also, Wolfram (1999) derives a form of Lerner Index as a measure of market performance for the generation sector in the UK.

The Borenstein et al. index focuses on differences in energy costs (valued at bid prices and short-run marginal cost, respectively). The index may be written:

$$\mathrm{MP}_t = \sum_{t=1}^{s} (P_t - \mathrm{MC}_t)\mathrm{MWH}_t / \sum_{t=1}^{s} P_t \mathrm{MWH}_t \qquad (2)$$

where $P$ represents the (bid) pool price, MC represents marginal supply costs, MWH is the amount of energy sold (all at the reference node in time period $t$), and $s$ represents the number of periods being analysed.

If there is no difference between pool prices and costs, the index (MP) has a value of zero—a positive value *over a sustained period of time* would lend support the view that there is market power. The measure may be applied to individual firms or to the industry as a whole.

The estimates of price–cost markups in studies such as those by Borenstein et al. (2000) and Wolfram (1999) are based on estimates of the *short-run marginal costs* of generation. But the importance of long-run issues is recognized. In the words of Borenstein et al. (2000):

> ...it is important to remember that current electricity prices influence long term decision making in a way that can seriously impact the economy and efficient investment. While it has been pointed out that high prices should spur new investment and entry in electricity production, these investments may not be efficient if motivated by high prices caused by market power, which may indicate not a need for new capacity, but for the efficient use of existing capacity. Conversely,

[3] The *industry-wide generalisation* of the Lerner Index may be expressed as:

$$L = \sum_{j=1}^{n} \left(P - \mathrm{MC}_j\right) s_j / P = \mathrm{HHI}(1 + v)/\varepsilon$$

where $n$ is the number of firms; $s_j$ is the market share of firm $j$; $\varepsilon$ is the market elasticity of demand; HHI is the Herfindahl–Hirshman index, or the sum of squares of market shares; and $v$ is a market conduct parameter, reflecting the behaviour of firms in the market, i.e., whether firms behave in a competitive or monopolistic manner. Hence $L$ is a weighted average of the individual Lerner indices. The value of $L$ depends on the values of $P$, MC, and $s_j$ (or alternatively, HHI, $v$, and $\varepsilon$); clearly, changes in the values of any one of these terms can be offset by changes in the others. If $v$=−1 the market is behaving in a competitive manner. The greater $v$ is above −1 (i.e., in a positive direction) the greater the divergence "... of price from marginal cost and the less competitive the market or, what is the same thing, the greater the exercise of market power" (Church and Ware, 2000, p. 273).

artificially high prices can lead some firms not to invest in productive enterprises that require the use of electricity (p. 8).

As mentioned, all of the above studies of market power in the electricity generation sector rely on oligopoly theory and in general use simulation techniques to model the behaviour of electricity generators. Researchers also use programming techniques to study costs in the electricity generation sector (see for example, Hobbs, 1986; Dowlatabadi and Torman, 1991; Tamaschke et al., 1995a,b, 1996, 2000) and programming models are one of the decision-making tools used by electricity generation firms throughout the world.

## 4. Analysing the exercise of market power in Queensland

### 4.1. Introduction

The discussion in the preceding sections suggests that the conditions for the exercise of market power exist in Queensland because of a number of entry barriers. These include the fact that there are relatively few generators compared with the size of the market, because Queensland has a capacity cushion (including announced generation projects) that is expected to be sufficient for a number of years, and because of inelastic demand, particularly in the short term (IRPC, 2001; NEMMCO, 2001b; Powerlink, 2001a, 2002).[4] The purpose of this section is to assess whether electricity generators in Queensland have exercised market power.

As the industry short-run marginal cost curve is typically upward sloping, price is equal to or greater than short-run marginal cost even in the competitive price-taking situation. Hence, in analysing electricity generation, special attention has to be given in distinguishing between *competitive market pricing* and *pricing that results from the exercise of market power.*

A review of the economics and strategic management literature provided earlier in this study highlights a number of factors that determine the significance of market power in an industry, and the need to consider the concept of market power in a long-run dynamic context. With regard to the latter, in Section 2 we drew attention to the argument (cited by Church and Ware, (2000, p. 603)) that not all market power justifies regulatory intervention, instead '[a]ntitrust enforcement is warranted if market power is significant and durable'. It was noted that '*significant*' means that prices are not only greater than

[4] Capacity cushion is defined as the difference between peak co-incident demand and installed capacity, measured at the generator terminal connection points. On an annual basis reserves in Queensland were equivalent to more than three times the minimum required by NEMMCO in all years analysed in this study. As discussed, the Queensland jurisdiction was prorogued until the opening of QNI interconnector between Queensland and New South Wales in February 2001, but since then the State has continued to have very high residual demand. For details on available and required capacity, QNI and residual demand since Queensland joined the NEM see Powerlink (2001a, 2002), NEMMCO (2001b) and IRPC (2001). Regarding elasticities, even the long-run elasticity is low. NIEIR have recently estimated the long-run price elasticity of electricity demand in Queensland to be in the range $-0.14$ to $-0.44$ (on this see NEMMCO (2001b, p. 3–27)).

marginal cost, but also greater than long-run average costs, providing firms with above normal returns, and that '*durable*' refers to a firm's ability to maintain above normal returns in the long run.

The approach used in this study is to consider whether there have been significant divergences (as defined above) from competitive prices since Queensland joined the NEM in December 1998. We will attempt to derive estimates of long-run industry supply costs using a programming model of the QEI and compare these with prices that came about from bidding behaviour in the NEM using a market power index (consistent with Borenstein et al., 2000 and Wolfram, 1999, as discussed in Section 3). In opting for a market-wide (rather than unit specific) approach to their analysis of market power in the electricity generation sector, Borenstein et al. (2000, p. 7) state:

> As such, these tests are less vulnerable to the arguments of coincidence, bad luck, or ignorance that can be applied to the actions of a specific generator. In general, (this approach tests) whether market prices are consistent with the hypothesis that the market as a whole is acting in a competitive manner. This approach is less informative about the specific manifestations of market power, but is effective for estimating its scope and severity, as well as identifying how departure from competition varies over time.

The analysis will focus on the years 1999 to 2002. These are the first 4 years after Queensland joined the national energy market.

### 4.2. The programming model

#### 4.2.1. Logic and background

As noted in Section 3, programming models have been widely used in analyses of electricity systems. In fact NEMMCO uses a programming dispatch model (NEMMCO, 1999, 2001c) in the Australian NEM.

In our study an important part of the analysis is to use a programming model of the Queensland system, previously devised by the authors (Tamaschke et al. (1995a,b, 1996, 2000)). The model has been expanded and updated for the purposes of this study as discussed below.

The logic of the programming model is based on economic efficiency criteria. Economically efficient prices are those that would prevail under highly competitive conditions, reflecting the marginal costs of supply at each receiving node. In the short-run, in which capacity is fixed, price ($p$) should reflect short-run marginal costs (srmc). In the long-run capacity can be varied. Hence, if the srmc is greater than long-run marginal cost (lrmc), and plant is divisible, capacity is expanded until such time as $p$=srmc=lrmc, which is consistent with efficient cost recovery. If the revenue raised under short-run marginal cost pricing (where price is set equal to the marginal cost of the last unit delivered) is insufficient to finance relevant (efficient) levels of capital expenditures (e.g., because of plant indivisibilities and/ or economies of scale), appropriate deviations from short-run marginal cost pricing will be required for cost recovery. Accordingly, our model allows us to deal with capital charges and the contribution of revenues to capital costs derived from setting prices on the basis of srmc. The competitive outcome including a normal return on capital is our benchmark for evaluating market outcomes. In other words, our approach provides estimates of revenues over and above short-run costs (quasi-rents) and thus enables us to determine revenues required to meet any capital shortfall.

In the previously most recently published version (reported in Tamaschke et al., 2000), the short-run model (summarised algebraically in Table 1) is concerned with minimising an objective function of 253 variables (including slacks and artificials) on the half hour. The model includes 11 power station supply constraints (7 thermal, one hydro, a pumped storage hydro (Wivenhoe), a group of combustion turbines, and a system stability minimum-production constraint).[5] Among other matters, the model has 9 bulk receivers (7 regional transmission connection points (distribution system entry points), one bulk industrial point, and the pumped storage hydro (PSH), when it is being pumped). One of the transmission connection points (TCPs) is South Pine, where the Queensland Regional Reference Node (RRN), QLD1, is located. Wivenhoe alternates between being a receiver and a generator, depending on the level of water in the storage pond and demand.

As a key output, the program provides a shadow price for each TCP (on the half hour), which may be interpreted as the short-run *system marginal cost* of supplying the last MWh to that TCP (for example South Pine), i.e., inclusive of marginal generation costs and transmission losses, and these *form the basis of our modelled costs*. These costs allow for interaction between all the power station capacities and demands at all of the TCPs. At each point in time, differences between the marginal costs at the various TCPs are due to marginal system losses. Relative to the South Pine TCP for example, these system marginal losses can be less than, equal to, or greater than unity (depending on relative load and location).

Capital costs (required for cost recovery) are then allocated, depending on the revenue shortfall under short-run marginal cost pricing.

The model can incorporate generation, transmission, and distribution costs (including environmental aspects). In this study the *focus will be on generation costs and transmission losses* for comparability with the Regional Reference Prices (RRPs) at QLD1.

### *4.3. Modifications, updates and assumptions for the present study*

The year 2000 version of the TDS programming model (including inputs) has been updated and modified for the purposes of this study in a number of ways. In particular:

- Station capacities and losses have been updated in line with Powerlink (2001a, 2002) and NEMMCO (2001b, 2002). In the case of the coal-fired stations, 6.5% of the rated

[5] In view of their close proximity, the two northern hydros were combined, as were the combustion turbines that are assumed to be located on the central coast. Because of location and the relatively small capacity of Callide A, Callide A and Callide B were included as one station. A single TCP is allocated as an entry point to each of the former distribution regions. For the 'South-East', South Pine is taken as the central load point. 'South East' combines 'Moreton North', 'Moreton South', and 'Gold Coast-Tweed'. The model also has one TCP each as distribution entry points for 'Far North', 'Ross', 'North Queensland', 'Central', 'Wide Bay', and 'South West'.

Table 1
The half-hourly short-run programming model

*Minimise* $\sum_{i=1}^{11}\sum_{j=1}^{9}\Sigma_k S_{ijk}x_{ijk}$
*Subject to*
*Supply constraints*
$\sum_{j=1}^{9}\sum_k l_{ijk}x_{ijk} \leq P_i(u_i), i=1,2,\ldots,10$
$\sum_{j=1}^{9}\sum_k l_{ijk}x_{ijk} = 320(u_i), i=11$ (system stability)
*Demand constraints*
$\sum_{i=1}^{11} x_{ijk} = MWH_{jk}(v_{jk})$,
$x_{ijk} \geq 0$, $l_{ijk} \geq 1$, *where*
$i$=1,2,. . .,11 (stations, including stability)
$j$=1,2,. . .,9 (bulk receivers)
$k$= 1,2,3 (regional classes);
$k$=1 (PSH and bulk industrial), and
$s_{ijk}$= the generation, transmission, distribution, and $CO_2$ emission costs associated with sending one MWh from station $i$ to region $j$ for end user class $k$;
$x_{ijk}$= the number of MWh received in region $j$ from station $i$ for end user class $k$;
$P_i$= $i$th station supply (MWh); total supply less 320 for Gladstone;
$MWH_{jk}$= demand of end user class $k$ in region $j$ (MWh);
$l_{ijk}$= transmission loss penalty factor associated with supplying the MWh required at the bulk supply point (BSP) of the $j$th distribution region to satisfy retail demand of the $k$th class in that region;
$u_j$ and $v_{jk}$ are dual values (or shadow prices), which may be read from the optimal tableau.

Source: Tamaschke et al. (2000, Table 1).

capacity (measured at the generator terminals) is assumed to be lost to drive station auxiliaries and transformers (NEMMCO, 2001b, pp. 3–27), and all stations are assumed to run at 90% availability. This means that for thermal stations some 84% of the rated (generator terminal) capacity is assumed to be available to be sent out into the transmission grid. The 90% availability is in line with experience in the QEI over many years.

- Generator fuel costs are updates of estimates obtained in earlier studies conducted by the authors for the period before 1996. These calculations were based on heat rates (kilojoules/MWh) and coal price data. As the commercially sensitive information on coal contracts of the generators is unavailable to us, the approach used for this study is to adjust the earlier results upward by half the CPI movements. Half CPI adjustments have been common place in the QEI for many years. For the later combustion turbine (CT) stations estimates are based on information in IRPC (2001).
- Operations and maintenance costs are assumed to be 2% of capital costs. This is in line with our earlier studies and also with figures quoted in IRPC (2001, p. 29). Generator market participation fees are as in NEMMCO (2000).
- The modelling uses industry demand data and load shapes from 1999/2000. The results for 2001 and 2002 assume that the earlier load shapes apply; these were scaled up by official demand growth estimates.
- Capital cost estimates used in the modelling represent estimated replacement costs and range between \$950 and \$1200 per kilowatt (in line with CGEY, 2000 and IRPC, 2001, respectively, for black-coal fired stations). Black coal-fired estimates are used because of the structure of the Queensland system. These numbers are also consistent with our

previous studies (referenced above) which examined investment patterns in the QEI between 1981 and 1996; when adjusted for inflation, these estimates fall slightly below the upper limit of $1200 per kilowatt. Capital cost estimates are gross costs before the subtraction of any revenue surplus from short-run marginal cost pricing (as discussed above).

- Various assumptions are made about the useful life of the plant ranging between 30 and 50 years. The 50 year estimate is in line with CGEY (2000). The present value of the generation capital is assumed to be repaid over the useful plant life with a constant annuity each year.
- The *real pre-tax interest rates* (i.e., pre-tax interest rates net of inflation) used in the modelling are 8%, 10%, and 12%. This range is included for two reasons. Firstly, application of the Capital Asset Pricing Model (CAPM) to Queensland's generation assets suggests a nominal 11% pre-tax as the 'average weighted cost of capital'. Using this number for 1999 (the base year for our modelling) translates to about 10% in real terms (using the CPI numbers in Table 2 as indicators of inflation).[6] Secondly, to 'satisfy the private market, real rates of at least 8%, and possibly closer to 12% have been suggested' in the literature (Bunn et al., 1993, pp. 959–60). If we take the 10 year Treasury Bill interest rates presented in Table 2 as indicative, in 1999 the average 'risk free' real interest rate would have been about 5%. The differences between this rate and the rates used in the modelling may be considered the electricity 'risk premiums'. The real rates for 2000, 2001, and 2002 suggested by Table 2 are even lower.
- The modelling includes several ancillary costs. These include spinning reserve costs for the thermal stations, a system stability constraint, and the running of the pumped storage hydro plant (Wivenhoe) which also serves (in part) as a synchronous condenser.
- For 2001 onwards, provisions can also be made for energy flows between Queensland and New South Wales.

The modelled long-run competitive cost estimates are exclusive of the goods and services tax (GST) and transmission network charges to be on a consistent basis with RRN prices. For the same reason, the modelled prices exclude extra payments made by NEMMCO directly to high cost stations on account of transmission constraints (for

[6] On this see Simshauser (2002). Strictly, the nominal pre-tax 11% return estimated by Simshauser is for the year 2000, suggesting a real rate of about 8% in that year (using the CPI numbers in Table 2); despite this we will use a real rate of 10% to be 'conservative'. The CAPM used is of the form:

$$\mathrm{MEC} = \mathrm{Rd}^{*}(D/V) + \mathrm{Re}^{*}(E/V)$$

where MEC=pre-tax, marginal efficiency of capital in nominal terms (the nominal 'average weighted cost of capital' in the jargon of financial economists), Rd=the cost of debt capital pre-tax, Re=the cost of equity capital pre-tax, $D$=the total value of debt capital employed by the generator, $E$=the total value of equity capital employed by the generator, $V$=the combined value of debt and equity capital employed by the generator. In these calculations the 10 year Treasury Bill rate (as per Table 2) is taken as the 'risk free' interest rate. This is combined with financial market data on the credit status of generators (most are on BBB or better), an estimated equity $\beta$ and a recent ACCC (2001) estimate of the long-run return of financial markets as a whole (taken as share market returns), which ACCC takes as 6% above the long bond rate. Debt equity weights are taken as 0.4 and 0.6, respectively, which are considered appropriate for Queensland generation.

Table 2
Average annual 10 year treasury bond rates and CPI movements, Australia 1999 to 2002

| Year | 10 year treasury bond rate (average % per year) | CPI movements (year on year, June quarter) |
|---|---|---|
| 1999 | 6.0 | 1.1 |
| 2000 | 6.3 | 3.2 |
| 2001 | 5.6 | 6 |
| 2002 | 5.8 | 2.8 |

Sources: Based on RBA (2002) and ABS (2001).
The 2001 CPI figure is artificially inflated because of the introduction of the GST from 1 July 2000.

example between Central and North Queensland); on this see Powerlink (2001b,c; 2002). The modelled prices are for the South Pine TCP, which is where the RRN is located and to which wholesale electricity prices in Queensland are referenced.

With these adjustments and assumptions, we believe that the modelled outcomes of this study are reflective of the NEM relationships as they apply to Queensland, bearing in mind that the RRPs are also based on economic efficiency concepts and that NEMMCO also use a programming dispatch model (e.g., NEMMCO, 2001c, 1999, p. 5). However, the RRPs (as published on www.nemmco.com.au) are based on bids by generators, which may or may not mirror the long-run costs of electricity generation. Hence, the marginal modelled costs and RRPs will be compared using a market power index (consistent with Borenstein et al., 2000, discussed in Section 3).[7]

The modelling uses data for four 'average seasonal' days for each of the years. The days were selected on the basis of seasonal weather conditions in consultation with industry experts. The mean half-hourly loads of these days are in line with the average annual half-hourly loads. The seasonal day results are used to provide weighted annual average long-run marginal costs for the Queensland system (with energy used as the weighting factor). Similarly, the half-hourly RRPs in each year were converted to an annual (weighted) average RRP for each year. *The aim of this approach is to iron out short-run fluctuations and uncover the longer-term tendencies, which are central to an analysis of market power* (as discussed earlier in this study).

The market power index used here is of the form:

$$\mathrm{MP}_t = (\mathrm{RRP}_t - \mathrm{MC}_t)^*\mathrm{MWH}_t/\mathrm{RRP}_t^*\mathrm{MWH}_t \qquad (3)$$

where $t$=calendar years (i.e., 1999, 2000, 2001, or 2002), $\mathrm{MP}_t$=market power index value in year $t$. $\mathrm{RRP}_t$=the mean (demand weighted) regional reference price per MWh at the RRN in year $t$. $\mathrm{MWH}_t$=total demand at the RRN in year $t$. $\mathrm{MC}_t$=the modelled annual average long-run marginal cost of delivering one MWh of electricity to the RRN in year $t$.

It follows that MP=0 when there is no difference between the RRP and modelled long-run marginal costs (the modelled long-run marginal costs are assumed to be equal to long-

[7] The analysis of this study focuses on private costs of generation, i.e., environmental costs have been ignored. If the Kyoto Protocol on greenhouse gas emissions is ratified, then environmental costs will need to be included, with significant implications for generation costs and conceivably for the potential for exercising of market power. On greenhouse gas emissions see Tamaschke et al. (2000).

run average costs due to our cost recovery assumption). If the RRP exceeds the modelled value, MP is positive.

#### *4.3.1. Sensitivity of the results*

For a given set of input assumptions, the modelled long-run costs, and hence the market power index values, are 'robust'. For example if the modelled costs resulting from the above approach (i.e., using the four average seasonal days) overestimate the short-run system marginal supply cost component, the overall short-run contribution to capital will be greater, resulting in a lower addition to cover capital costs in stage two of the estimation process. Similarly, if the modelled short marginal costs are too low, the lower will be the short-term contribution to capital, and the greater the addition required to cover capital costs in stage two.

In addition, the authors also attempted to derive system cost estimates independently of the model (but using the same input assumptions). This '*method 2*' was based on the marginal costs that would be incurred by the annual average hourly load, with allowances for average transmission network losses. The results obtained in this way strongly support the results obtained with the aid of the programming model ('*method 1*').

### *4.4. Interpretation of the results*

Table 3 provides the results for calendar years 1999 through to 2002. The Table presents the market power (MP) indices based on modelled long-run cost recovery prices for useful plant lives of 30, 40, and 50 years, capital costs of \$950/kW and \$1200/kW, and real interest rates of 8%, 10%, and 12%. As explained earlier, a real interest rate of 10% is a 'conservative' CAPM-based estimate for generation in Queensland.

The modelling underlying the Table was performed at constant June Quarter 1999 prices.[8] The results for the years 2000, 2001, and 2002 were then adjusted for inflation to make them comparable with the RRPs in those years. The inflation rate for 2001 was discounted to make allowances for the once off effects on the CPI of the introduction of the GST from 1 July 2000. Half CPI adjustments were used in line with common QEI practice.

The results of Table 3 suggest that:

- For 1999, the MP index is positive for nearly all scenarios. For example, if the useful plant life is 40 years, and the real interest rate is 10% (the conservative CAPM-based estimate) the MP index is between 0.17 and 0.05 (for capital costs of \$950/kW and \$1200/kW, respectively). Under this scenario, the actual electricity prices are 5% to 17% higher than under competitive conditions (using actual prices as the base). This translates to \$2.26 to \$7.76 per MWh on a demand weighted basis. For the \$1200/kW capital scenario the modelled cost per MWh is \$43.74[9] which would more than cover the long-run marginal costs suggested for Queensland's major thermal stations (in IRPC, 2001, p. 97) when the station loss factors stated in NEMMCO (2001a) are

[8] As inflation was about 1% in our base year, 1999 (as per Table 2), to obtain real interest rates of 8%, 10%, and 12%, the percentages used in the calculations were 9, 11, and 13%, respectively.

[9] Calculated as per note beneath Table 1.

Table 3
Market power indices 1999, 2000, 2001, and 2002

| Capital scenario (years, real interest rate, $/kW) | | | Index values (MP) (equal to 0 when no price difference) | | | |
|---|---|---|---|---|---|---|
| | | | Year | | | |
| | | | 1999 | 2000 | 2001 | 2002 |
| 50, | 8%, | 950 | 0.24 | 0.36 | 0.03 | 0.30 |
| 50, | 8%, | 1200 | 0.14 | 0.28 | −0.10 | 0.21 |
| 40, | 8%, | 950 | 0.23 | 0.35 | 0.01 | 0.29 |
| 40, | 8%, | 1200 | 0.12 | 0.27 | −0.12 | 0.20 |
| 30, | 8%, | 950 | 0.20 | 0.33 | −0.02 | 0.27 |
| 30, | 8%, | 1200 | 0.09 | 0.24 | −0.16 | 0.17 |
| 50, | 10%, | 950 | 0.17 | 0.31 | −0.06 | 0.24 |
| 50, | 10%, | 1200 | 0.05 | 0.21 | −0.21 | 0.13 |
| 40, | 10%, | 950 | 0.17 | 0.30 | −0.07 | 0.24 |
| 40, | 10%, | 1200 | 0.05 | 0.20 | −0.21 | 0.13 |
| 30, | 10%, | 950 | 0.16 | 0.29 | −0.08 | 0.23 |
| 30, | 10%, | 1200 | 0.03 | 0.19 | −0.24 | 0.11 |
| 50, | 12%, | 950 | 0.10 | 0.25 | −0.15 | 0.18 |
| 50, | 12%, | 1200 | −0.03 | 0.13 | −0.32 | 0.05 |
| 40, | 12%, | 950 | 0.10 | 0.25 | −0.15 | 0.17 |
| 40, | 12%, | 1200 | −0.04 | 0.13 | −0.33 | 0.05 |
| 30, | 12%, | 950 | 0.09 | 0.24 | −0.17 | 0.17 |
| 30, | 12%, | 1200 | −0.05 | 0.12 | −0.34 | 0.04 |
| Average RRP ($MWh) | | | 46.04 | 55.59 | 37.06 | 52.54 |
| RRN MWh (millions) | | | 39.78 | 42.23 | 43.75 | 45.80 |

The modelled marginal costs may be obtained by evaluating the term: RRP(1−MP).

applied. The issue of a 'reasonable (normal) return on capital' in electricity generation is clearly worthy of discussion, bearing in mind that at this time the real 10 year Treasury Bond rate was about 5% (Table 2).

- For 2000 the results are even more striking. In the case of the example cited above, the index is now between 0.20 and 0.30 that translates to $11.26 to $16.83 per MWh on a demand-weighted basis.
- For 2001 the data which suggest positive differences are not nearly as prevalent as for 1999 and 2000—small positive divergence occur only for cost estimates based on lower interest rates and capital costs.
- For 2002 the divergences are almost as large as for the year 2000. Here, under the comparable scenario, the index is between 0.13 and 0.24, which translates to $6.77 to $12.49 per MWh on a demand-weighted basis (Table 3).
- Inspection of Table 4 shows that the annual average RRPs (and hence the MP index values) were significantly shaped by 'extreme conditions' in a few months each year.

We have seen the conditions for the exercise of market power exist in Queensland and the above results suggest that the Queensland generation sector was able to earn a higher rate of return than might reasonably be expected under competitive conditions in 1999, 2000, and 2002. So what might explain the lower divergences shown by our indices in

Table 4
Mean annual and monthly regional reference prices (Queensland)

| Month | Year | | | |
|---|---|---|---|---|
| | 1999 ($MWh) | 2000 ($MWh) | 2001 ($MWh) | 2002 ($MWh) |
| January | 115.15 | 118.61 | 64.87 | 32.61 |
| February | 48.52 | 38.10 | 44.35 | 45.96 |
| March | 112.08 | 71.41 | 57.51 | 26.90 |
| April | 31.46 | 38.35 | 29.79 | 26.21 |
| May | 33.46 | 52.94 | 37.91 | 71.90 |
| June | 27.96 | 82.85 | 35.26 | 74.06 |
| July | 25.16 | 53.46 | 28.06 | 98.48 |
| August | 48.61 | 45.72 | 27.93 | 31.96 |
| September | 21.94 | 32.25 | 25.10 | 29.63 |
| October | 23.65 | 44.76 | 45.14 | 36.09 |
| November | 30.03 | 37.36 | 22.72 | 38.72 |
| December | 30.40 | 48.12 | 25.43 | 113.91 |
| Annual mean price | 46.04 | 55.59 | 37.06 | 52.54 |

Source: These figures are weighted averages calculated by the authors from half-hourly data provided on www.nemmco.com.au. Half-hourly prices were weighted according to the stated electricity demands.

2001? The answer probably lies in the structure of hedge contracts between the generators and their customers.

Unfortunately, details of these contracts are commercial in confidence and therefore unavailable for analysis. However, information gleaned from various industry sources leads us to believe that in 2001 about 60% of *industry output* may have been contracted at an average price of the order of $35/MWh. Essentially, these (hedge) contracts, which are outside the NEM pool price, agree on a delivery price—if the pool price is higher than contracted, generators reimburse customers the difference and vice versa. For a given market price a firm will face a particular residual demand and this could be higher or lower than its contract cover. Now if the contract cover *for a firm* is greater than its residual demand at the market price, it has been shown that the optimal strategy is for generators to bid below marginal cost.[10] This last point may provide the clue to the 2001 results. A new low cost Queensland-based generation plant of some 800 MW capacity was commissioned by one of the incumbents, making some existing stations less competitive. Also the QNI interconnector with New South Wales was commissioned in that year with an import capacity of up to 500 MW, and again at a lower cost than some of the existing Queensland stations. It does not seem unrealistic to assume that this would have adversely affected the residual demand of some incumbents relative to their contract cover, resulting in a tendency to 'bid low' and lower pool prices in 2001. By 2002, some adjustments in contracts would have been possible with consequent

[10] The firm's realised period-level profits may be written: $\pi(p)=(DR(p)-QC)(p-MC)+(PC-MC)QC$; where $p$ is market price; DR($p$) is residual demand at price $p$; MC is the firm's marginal cost of producing a MWh; PC is the quantity weighted contract price; QC is contract quantity. For a given contract cover the last term is fixed. If QC is greater than DR($p$), it follows that the firm's optimal bid strategy is to bid at less than its marginal cost. See Wolak (2000) for further details.

implications for the relativities between residual demand and contract cover and hence bid prices.

## 5. Conclusions

The purpose of this study is to investigate the potential for the exercise of market power in the Queensland electricity generation sector, and the extent to which it has been exercised. A market power index was constructed focusing on differences between actual market returns and long-run competitive (marginal cost) prices. The marginal cost estimates were obtained using a programming model of the Queensland system devised by the authors. The paper also considers the market power implications of hedge contracts.

All up our results support the view that Queensland generators (presumably the four dominant corporations) have been able to exercise market power through their business strategies since Queensland's entry into Australia's National Electricity Market in December 1998. Given the paucity of the data available to us on individual generators, it is difficult to assess the relative importance of the possible contributing factors, including the role of specific generators. Economic theory and the results of some empirical work in other countries and for other states in Australia suggest that barriers to entry and strategic behaviour are important determinants. This aspect will be a subject for future research once more of the relevant data are available.

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