# PRICE AND VOLATILITY RELATIONSHIPS IN THE AUSTRALIAN ELECTRICITY MARKET

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Abstract

This thesis presents a collection of papers that has been published, accepted or submitted for publication. They assess price, volatility and market relationships in the five regional electricity markets in the Australian National Electricity Market (NEM): namely, New South Wales (NSW), Queensland (QLD), South Australia (SA), the Snowy Mountains Hydroelectric Scheme (SNO) and Victoria (VIC). The transmission networks that link regional systems via interconnectors across the eastern states have played an important role in the connection of the regional markets into an efficient national electricity market. During peak periods, the interconnectors become congested and the NEM separates into its regions, promoting price differences across the market and exacerbating reliability problems in regional utilities. This thesis is motivated in part by the fact that assessment of these prices and volatility within and between regional markets allows for better forecasts by electricity producers, transmitters and retailers and the efficient distribution of energy on a national level.

The first two papers explore whether the lagged price and volatility information flows of the connected spot electricity markets can be used to forecast the pricing behaviour of individual markets. A multivariate generalised autoregressive conditional heteroskedasticity (MGARCH) model is used to identify the source and magnitude of price and volatility spillovers within (intra-relationship) and across (inter-relationship) the various spot markets. The results show evidence of the fact that prices in one market can be explained by their own price lagged one-period and are independent of lagged spot prices of any other markets when daily data is employed. This implies that the regional spot electricity markets are not fully integrated. However, there is also evidence of a large number of significant own-volatility and cross-volatility spillovers in all five markets indicating that shocks in some markets will affect price volatility in others. Similar conclusions are obtained when the daily data are disaggregated into peak and off-peak periods, suggesting that the spot electricity markets are still rather isolated.

These results inspired the research underlying the third paper of the thesis on modelling the dynamics of spot electricity prices in each regional market. A family

of generalised autoregressive conditional heteroskedasticity (GARCH), RiskMetrics, normal Asymmetric Power ARCH (APARCH), Student APARCH and skewed Student APARCH is used to model the time-varying variance in prices with the inclusion of news arrival as proxied by the contemporaneous volume of demand, time-of-day, day-of-week and month-of-year effects as exogenous explanatory variables. The important contribution in this paper lies in the use of two latter methodologies, namely, the Student APARCH and skewed Student APARCH which take account of the skewness and fat tailed characteristics of the electricity spot price series. The results indicate significant innovation spillovers (ARCH effects) and volatility spillovers (GARCH effects) in the conditional standard deviation equation, even with market and calendar effects included. Intraday prices also exhibit significant asymmetric responses of volatility to the flow of information (that is, positive shocks or good news are associated with higher volatility than negative shocks or bad news).

The fourth research paper attempts to capture salient feature of price hikes or spikes in wholesale electricity markets. The results show that electricity prices exhibit stronger mean-reversion after a price spike than the mean-reversion in the normal period, suggesting the electricity price quickly returns from some extreme position (such as a price spike) to equilibrium; this is, extreme price spikes are short-lived. Mean-reversion can be measured in a separate regime from the normal regime using Markov probability transition to identify the different regimes.

The fifth and final paper investigates whether interstate/regional trade has enhanced the efficiency of each spot electricity market. Multiple variance ratio tests are used to determine if Australian spot electricity markets follow a random walk; that is, if they are informationally efficient. The results indicate that despite the presence of a national market only the Victorian market during the off-peak period is informationally (or market) efficient and follows a random walk.

This thesis makes a significant contribution in estimating the volatility and the efficiency of the wholesale electricity prices by employing four advanced time series techniques that have not been previously explored in the Australian context. An understanding of the modelling and forecastability of electricity spot price volatility across and within the Australian spot markets is vital for generators, distributors and market regulators. Such an understanding influences the pricing of derivative contracts traded on the electricity markets and enables market participants to better manage their financial risks.

*Keywords*: spot electricity price markets; mean and volatility spillovers; multivariate GARCH; normal asymmetric power ARCH (APARCH); Student APARCH; skewed Student APARCH; price spikes; mean-reversion; multiple variance ratio tests; market efficiency and random walk.

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## Statement of Original Authorship

This thesis is submitted to the Queensland University of Technology in fulfilment of the requirement for the Degree of Doctor of Philosophy.

This thesis represents my own work and contains no material which has been previously submitted for a degree or diploma at this University or any other institution, except where acknowledgement is made.

Signature …………………………………….

Helen Higgs

Date: ……………………………………..

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## Notes on the Structure and Format of the Thesis

This thesis is for a PhD by publication. Chapters 4 to 8 consist of published papers, papers accepted for publication and papers submitted for publication or under editorial review during the period of candidature. Where papers have multiple authorship, the candidate must be principal author of at least two of three papers (minimum number of papers is normally three) and have written permission of the co-authors. This requirement has been met. The remaining sections (Abstract, Introduction, Background to the Australian Electricity Market, and Literature Review) link and summarise the research papers to provide a coherent narrative to the overall structure of the thesis. References are provided at the end of each section and publication rather than at the end of the entire thesis.

## List of Publications in Order of Presentation

Worthington, A.C., Kay-Spratley, A. and Higgs, H. (2005) Transmission of prices and price volatility in Australian electricity spot markets: A multivariate GARCH analysis, *Energy Economics*, 27(2), 337-350.

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Higgs, H. and Worthington, A.C. (2005) Systematic features of high-frequency volatility in Australian electricity markets: Intraday patterns, information arrival and calendar effects, *Energy Journal*, 26(4), 23-41.

Higgs, H. and Worthington, A.C. (under editorial review) Stochastic price modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market, under editorial review at *Resource and Energy Economics*.

Higgs, H. and Worthington, A.C. (2003) Evaluating the informational efficiency of Australian electricity spot markets: Multiple variance ratio tests of random walks, *Pacific and Asian Journal of Energy*, 13(1), 1-16.

# Statement of Contribution of Co-Authors

The undersigned hereby certify that:

1. they meet the criteria for authorship in that they have participated in the conception, execution, or interpretation, of at least that part of the publication in their field of expertise;
2. they take public responsibility for their part of the publication, except for the responsible author who accepts overall responsibility for the publication;
3. there are no other authors of the publication according to these criteria; and
4. potential conflicts of interest have been disclosed to (a) granting bodies, (b) the editor or publisher of journals or other publications, and (c) the head of the responsible academic unit.

In the case of Chapter 4, contributions to the work involved the following:

| Contributor | Statement of contribution* | Publication title and date of publication or status* |
|---|---|---|
| A.C. Worthington*<br>Signature<br>8 September 2006 | Wrote manuscript and data analysis | Worthington, A.C., Kay-Spratley, A. and Higgs, H. (2005) Transmission of prices and price volatility in Australian electricity spot markets: A multivariate GARCH analysis, Energy Economics, 27(2), 337-350. |
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| H. Higgs*<br>Signature<br>8 September 2006 | Wrote manuscript, wrote methodology, conducted empirical estimation, documented empirical results and wrote conclusions and policy implications | Worthington, A.C., Kay-Spratley, A. and Higgs, H. (2005) Transmission of prices and price volatility in Australian electricity spot markets: A multivariate GARCH analysis, Energy Economics, 27(2), 337-350. |

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| A.C. Worthington*<br>Signature<br>8 September 2006 | Wrote manuscript and data analysis | Higgs, H. and Worthington, A.C. (2003) Evaluating the informational efficiency of Australian electricity spot markets: Multiple variance ratio tests of random walks, Pacific and Asian Journal of Energy, 13(1), 1-16. |

# 1 Introduction

This thesis uses econometric or time series techniques to model spot electricity prices in the newly-deregulated Australian electricity market. Australia is one of the more recent economies to embrace deregulation in its electricity markets, with deregulation beginning much earlier in the United Kingdom, Norway, Spain and the United States. The process of deregulation removed monopolistic price controls and openly encouraged market competition. Under regulation in Australia, prices were set by the states and had little variation as the price was set at marginal cost. Since deregulation, electricity prices have become increasingly volatile and various financial products have emerged as purchasers hedge price risks and investors search for new investments. Electricity derivative markets are established to implement hedging strategies where large price spikes are experienced in the summer or winter months. As a result of deregulation, there has been an increase in the importance of modelling and forecasting of electricity prices, which is the motivation of this thesis.

The quantitative models used attempt to capture the stylised features of the spot electricity prices and price volatility of five regional electricity markets in the Australian National Electricity Market (NEM), namely: New South Wales (NSW), Queensland (QLD), South Australia (SA), the Snowy Mountains Hydroelectric Scheme (SNO) and Victoria (VIC).

The empirical studies are constructed so as to address the following research questions. First, with interconnectors joining regional markets to promote a nationally efficient market, can the impact of lagged price and volatility information flows of the connected spot markets be used to improve forecast of pricing behaviour in individual markets? Second, can the inclusion of news arrival as proxied by the lagged volume of demand, time-of-day, day-of-week and month-of-year effects be used as exogenous variables in explaining the intraday price volatility process in each regional spot electricity market? Third, can the spikes in wholesale electricity prices be quantified separately from the normal mean-reverting regime? Fourth, has interstate/regional trade enhanced the efficiency of individual spot electricity market?

The thesis itself is structured as follows. Chapter 2 focuses on the background of the Australian electricity markets before and after deregulation and how the restructuring has changed pricing in the electricity industry. Chapter 3 illustrates the different characteristics or stylised features such as seasonality, mean-reversion, volatility and jumps or spikes, which are inherent in deregulated wholesale electricity prices. This chapter also provides a literature review, which highlights the important research that has motivated this study.

The published paper entitled "Transmission of price and price volatility in Australian electricity markets: a multivariate (generalised autoregressive conditional heteroskedastistic) GARCH analysis" which forms Chapter 4 presents a multivariate process to identify the presence of price and price inter-relationship between Australian regional electricity markets. Chapter 5 is based on the published paper entitled "Transmission of prices and volatility in the Australian electricity spot markets". This chapter extends the research into the dynamics of inter-relationships across the regional electricity markets by separating the daily data used in Chapter 4 into peak and off-peak periods in order to assess if further evidence exists of prices and price volatility relationships between the interconnected regional electricity markets.

"Systematic features of high-frequency volatility in Australian electricity markets: Intraday patterns, information arrival and calendar effects" in Chapter 6 employs a range of autoregressive processes to model the time-varying variance in electricity prices for each regional electricity market. News arrival is proxied by the lagged volume of demand, time-of-day, day-of-week and month-of-year effects. These variables are used as exogenous variables to take account of the volatility shocks that may cluster and persist over time and eventually revert to some normal level.

Chapter 7 entitled "Stochastic price modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market" attempts to capture one of the salient features of price hikes or spikes in spot electricity market using a regime switching model.

Chapter 8 investigates if interstate/regional trade has enhanced the efficiency of each spot electricity market. It employs some additional time series literature to determine if each spot electricity market follows a random walk (is informationally efficient). Chapter 9 concludes the thesis, and provides direction for future research.

In sum, the liberalisation of the Australian electricity market has changed the pricing landscape in this essential industry. The main contributions of this thesis lie in the application of time series quantitative techniques to assess the price and price volatility between and within regional electricity markets. This may be used to demonstrate the ability of the NEM in its capacity to foster a nationally integrated and efficient electricity market. Evidence to date suggests electricity spot prices can vary according to the time of day, temperature, location and various market conditions. Another observation is that lower prices in the deregulated electricity industry have also been accompanied by an erratic pattern of price spikes leading to greater price volatility. Whether this increased volatility persists and is likely to be exacerbated in the future is a matter of interest to market participants who heavily rely on up-to-date knowledge of electricity price risk.

# 2 The Australian Electricity Industry

## 2.1 Introduction

Since the 1990s, Australia has been at the forefront of the push to introduce competition into the electricity industry. Where electricity was once supplied by state government owned entities, the market is now characterised by separation of the generation, transmission and distribution functions across commercialised and privatised companies. The nature of electricity industries changed significantly as governments, suppliers and consumers embraced the concept of globalisation and economic reform. As part of microeconomic reform, an important shift resulting in a move away from the heavily regulated, vertically integrated state-based monopolies of the past to more integrated market-based structures for electricity suppliers in the present, and towards potentially more competitive outcomes for consumers in the future.

To introduce reform, the relevant Australian eastern states agreed to establish a National Electricity Market (NEM). The participating jurisdictions included New South Wales (including the Australian Capital Territory), Victoria, Queensland, South Australia and eventually Tasmania with the interconnector Baselink connecting Tasmania to the mainland. The objectives of the NEM were to separate the three vertically integrated operational divisions – generation, transmission and distribution – and to create a pool or wholesale markets in which generators sell electricity to wholesalers and retailers and ultimately to end-users (Quiggin, 2004). Each jurisdiction in the NEM had to determine the extent of disaggregation and privatisation of its electricity supply industry, and to establish interconnectors linking its generators to generating systems in other jurisdictions (Outhred, 2004).

The structure of the electricity supply industry can be functionally divided into three operational divisions: generation, transmission, and distribution. Before deregulation, all electricity supply industries in each state were vertically integrated, with generation, transmission and distribution under common or state ownership. There was also a substantial amount of horizontal integration in the industry with most states operating more than one generation plant, more than one transmission line and several distribution facilities. The role of the electricity supply industry was to manage and operate the divisions as a single entity. It is important to differentiate the technological and economical functions of each of the three divisions so as to understand the regulatory reforms introduced to disaggregate the electricity industry (Steiner, 2000).

The purpose of this chapter is to examine the Australian electricity supply industry and its reforms as it progressed from a regulated monopoly to a deregulated market. There is a need to understand the functional structures of this industry and the implementation of economic reforms to put this vital industry on a more competitive footing. The deregulation process also led to pricing reforms that better reflected the underlying costs and provided significant savings to end-users (Australian Bureau of Statistics: Year Book Australia, 2002).

### 2.1.1 Generation

The role of the generator is to use a range of primary energy sources (coal, natural gas and oil) as well as the flow of water (hydroelectric) to produce a secondary source of energy, electricity. The mechanism of a coal fired power generator requires the grinding of coal into a powder and then burning it to produce steam in large boilers at very high pressure. The steam then drives a turbine coupled to an alternator, which then converts the mechanical energy into an alternating current or electricity. Electricity is energy in the form of a flow of electrons along a conductor.

Recent policy measures have been introduced to support the advancement of renewable energy technologies such as solar, wind, wood and woodwaste, bagasse (sugar cane waste) and biofuels, such as landfill gas and sewage gas (Outhred and Watt, 2001). The commercial viability of a power plant depends, inter alia, on the cost of the type of fuel used in generation. Commonly, fossil fuelled generators supply base-load, while hydro and gas technologies supply peak-load. Varying types of generating technology and cost structure can improve efficiency by optimising the use of resources to ensure a balance of supply and demand for electricity in real time.

The associated efficiency gains should ultimately produce lower electricity prices to end-users. In Chapter 8, quantitative techniques are used to assess if the deregulated spot Australian electricity markets have become more market or informationally efficient over time.

### 2.1.2 Transmission

Transmission in the supply industry employs a grid of high tension or high voltage wires to facilitate the transfer of bulk energy from the generator to the location of the end-users. A transformer converts the generated electricity from low to high voltage to ensure efficient transport via the transmission wires. In a contemporary electricity supply industry, the transmission function jointly coordinates the planning and operation with the generating function. The transmission coordination function can often be viewed as a natural monopoly as one transmission line can be used to transmit electricity from the generator to the location of end-users (IEA, 2001).

Transmission investments can be perceived as entirely sunk costs. Once the transmission lines and switching stations are established they are prohibitively costly to move and are characterised by increasing economies of scale. Such efficiency gains prevent competitive entries into the transmission division, as these could be very costly to the company and also to the end-user. A key feature of deregulation in the electricity industry is to increase competition in transmission networks by linking regions via interconnectors with the goal to establish efficiency and stability in electricity prices across regional markets (Gallaugher, 2004). Chapters 4 and 5 focus on quantitative models to examine the dynamics of price and volatility relationships with an increased number and capacity of interconnectors linking the Australian regional electricity markets.

### 2.1.3 Distribution

The function of the distribution networks is to transform high voltage electricity provided by generators to low voltage electricity via transformers in sub-stations for distribution of electricity to end-users. The operating costs of transmission and distribution will be small compared to capital costs, implementing considerable economies of scale in distribution. The distribution function can be considered as a natural monopoly. The contemporary electricity industries often combine the function of distribution with the retailing business which then sells the electricity to end-use customers namely; industrial, commercial and domestic users. Deregulation has meant that competition is also encouraged in the distribution and retailing area with end-use customers eventually being able to purchase power from suppliers of their choice (NEMMCO, 2004). This liberalisation of the distribution and retailing of electricity will eventually affect the pricing of this commodity.

## 2.2 Economics of the Electricity Supply

The electricity supply industry operates in a relatively dynamic manner, primarily due to the unique economic characteristics of electricity supply and demand. On the supply side, once electricity is generated it cannot be easily stored or inventoried for future use, thus supply must vary dynamically as a function of instantaneous consumer demand. In addition, there is an obligation imposed on the industry by consumers and regulators for a continuous and reliable supply. The power supply systems must ensure that electricity supply and consumption be balanced and matched instantaneously in order to provide electricity at safe and acceptable quality standards (NEMMCO, 2004). The electricity supply must be operating at a reliable frequency and voltage suitable for industrial operations and household appliances and must also attempt to prevent outages (complete blackouts) and brown-outs (drops in voltages due to inadequate transformers).

The demand for electricity, commonly known as load, can be highly volatile due to fluctuations from the time of day, temperature or economic activities. The demand for electricity varies during the day, with low load levels from midnight to 7:00am, peak-load from 7:00am to 9:00am and again from the evening from 4:00pm to 7:00pm (NEMMCO, 2005a). For a given period, the size of load is strongly correlated with temperature, especially with the increasing usage of air-conditioning during the summer months and heating during the winter months. The variation in demand is greater for small or residential consumers than large industrial consumers.

Electricity markets in terms of generation, transmission and distribution networks also display many of the characteristics of a natural monopoly. Joskow (2000) defines a natural monopoly as:

> A natural monopoly is an industry where supply costs have the characteristic that it is less costly to supply output in a single firm than in multiple competing firms. In a single product industry, a sufficient condition for natural monopoly is the presence of increasing returns to scale or, equivalently, economies of scale over the range of output defined by the aggregate demand for the production produced by the industry.

Owing to intensive capital costs, any duplication of the transmission and distributions systems would lead to overinvestment in capital and subsequently to higher costs for consumers. Crew and Kleindorfer (1986: 3) noted the classic example that “there are definite cost savings in having only one water main in the street”. The presence of natural monopoly has influenced the regulatory regime for the electricity supply industry throughout the world.

### 2.2.1 Regulated Electricity Industry

Prior to the 1990s, the Australian electricity industry was state-owned and managed by vertically-integrated authorities responsible for the generation, transmission, distribution and retailing of electricity to commercial and domestic consumers, with limited interconnections between states as depicted in Figure 2.1. Regulation of the electricity supply industry was initially introduced owing to the presence of the natural monopoly and public good characteristics of its market structure. The regulation of a natural monopoly involves strict government oversight, usually pertaining to the strategic importance of the industry to the welfare and economy of the state. In the case of the electricity industry, this allows for a reliable, sustained supply of the good to the community and recognises the role it plays as a factor of production in the manifestation of other goods. Traditionally, governments also play a large role in the administration of the utility industries under regulated natural monopolistic models.

It was the vast capital cost of power stations for generation, the transmission grids and the distribution networks that was the main reason for the state governments to manage almost the entire electricity supply industry in Australia (Saddler, 1981). There were also the high costs of transporting electricity over long distances with a limited number of interconnectors linking different states, such as the connection between New South Wales and Victoria via the Snowy River Hydroelectric Scheme.

The electricity industry had been largely the responsibility of state governments. As a result, there was no private capital invested in the production and supply of electricity in Australia (Saddler, 1981).

**FIGURE 2.1** ***Regulated Electricity Market Structure***

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Source: Botto (1999).

### 2.2.2 Electricity Pricing Before Deregulation

Although electricity is sometimes erroneously considered as a single, uniform or homogeneous commodity, the cost of supplying it to a customer varies according to the time-of-day and month-of-year in which it is supplied, and the quantity which the customer uses. Supplying authorities competed with other suppliers of close substitutes, such as gas or oil, but did not compete with other authorities as they were publicly-owned monopolies. All the electricity authorities had a statuary commitment to meet costs and possibly to contribute a surplus to the revenue of each state government. The authorities were also obliged to supply electricity as cheaply as possible to their customers; and subject to the constraints of safety and technical reliability, to provide a safe, economic and effective supply of electricity (Saddler, 1981).

The regulated authorities were obliged to minimise damages to the environment and promote efficient energy use by such means as cogeneration. Cogeneration is the generation of electricity as a by-product of another process, and usually involves the recovery of heat that would otherwise have been wasted (Roarty, 1998). Meeting these two objectives requires complex pricing policies, as each authority has several power stations to supply the interconnected distribution grid. The operating and capital costs of each power station can vary substantially. The demand for electricity or load on the grid varies during the day according to low or peak-load levels. In addition, the daily load and peak demand are higher in the winter and summer because additional power is required for cooling in the summer months and lighting and heating in the winter months. With these variations in load, some power stations operate only part of each day to meet the intermediate and peak-loads; while others supply the base-load and operate continuously except for periods of breakdown or maintenance. This is prioritised according to the least-cost order of merit.

The cost of generation for the whole interconnected system is minimised if the power stations with the lowest operating costs are more frequently used. It is noted that hydroelectric power stations have very low operating costs and have the ability to start up very quickly. This makes them ideally suited for supplying peak and intermediate demands. The extent to which hydroelectric power stations are reserved to meet these demands depends largely on the capacity of hydro stations and availability of water. The Snowy scheme supplies a substantial proportion of peak and intermediate load to New South Wales and Victoria, but no base-load. In Queensland and South Australia where there are no hydroelectric power stations, peak power is provided by gas turbines that are operated by natural gas. Most electricity authorities employ large modern coal fired power stations for base-load, as these power stations are most efficient with the lowest fuel requirement per unit of electricity generated and hence operate at the lowest cost. The older and less efficient coal power stations and also ones that burn oil are used for intermediate and peak-load. With an increasing price in petroleum products, the ones that burn oil have the highest operating costs (Saddler, 1981). There is a huge literature in this area.

The literature associated with economic theory emphasises that according to the regulation of natural monopoly pricing, the most efficient allocation of resources is achieved when price is set equal to its marginal cost. In the electricity industry, off-peak prices should be lower than average prices and peak prices should be higher than average. The disadvantage of marginal cost pricing is that total revenues obtained will not match total costs incurred, being lower (high) when the long run marginal costs are falling (rising) (Nicholson, 1998). Prior to the 1990s, the electricity supply industry was comprised of publicly owned, vertically integrated suppliers operating in separate, extensively regulated state-owned markets. This resulted in significant over employment and over investment, and inflated electricity costs and prices which did not reflect the cost of supplying to different classes of users. For these reasons, many electricity industries embraced economic reform. Because the regulators fixed electricity prices depending on the generation, transmission and distribution costs, there was very little uncertainty, risk or volatility in electricity prices under regulation.

### 2.2.3 Regulatory Reforms in the Electricity Supply Industry

The impetus behind economic restructuring in the electricity supply industry is that "regulatory reform is focused on functional separation of generation and transmission, introduction of competition in generation and expanded network access. More advanced stages of reform tend to include the formation of electricity spot markets for electricity price determination and trade, and unconstrained choice of suppliers" (Steiner, 2000). The economic structure of the liberalised electricity supply industry is illustrated in Figure 2.2.

From the generator's point of view, an additional unit of kilowatt demanded at 1:00am during the winter months, when the generator is operating below capacity, is a different good compared to an additional unit produced at 12:00noon during the hot summer months, when the generator is operating at full capacity. To the consumer, one unit of electricity may be considered to be indistinguishable from any other units. On the other hand, Joskow and Schmalensee (1985) argue that:

> the [electricity generated] products are in fact often distinct from the customer's point of view as well; it is likely to be worth more to most people to be able to turn up an air-conditioner on a very hot day than to use the same amount of electricity to run a can opener…[thus] neglect[ing] the multiproduct nature of electricity supply may be seriously misleading.

**FIGURE 2.2** ***Deregulated Electricity Market Structure***

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Source: Botto (1999).

The cost of generation can also be differentiated by the type of fuel used. For example, oil and natural gas operated power plants are generally more expensive than coal-burning plants. The generation sector should also take full advantage of all available technologies including cogeneration, hydro, solar, wind and fossil fuel. There are definite product differentiations in production and cost.

Technological advances have introduced competition in the generation sector by reducing the minimum efficient scale (Steiner, 2000). Technological changes have reduced the importance of economies of scale, economies of scope and economies of vertical integration and have promoted and encouraged competitive markets to replace regulated monopoly in some divisions in the electricity industry. This underlying competitive reform process spurring the evolution of global electricity markets has instigated changes to the structure of the electricity supply industry, and in the composition of ownership for this infrastructure intensive industry.

The final reform in the generator function lies in legal ownership, where many electricity industries have moved away from state-owned to private concerns. Consequentially, reform initially tends to liberalise generation from the other functions. This vertical unbundling of utilities allows a competitive environment to be fostered between generators, before further reform is to take place.

The role of the transmission function is to transport power and coordinate the efficient supply of power to the end consumers. The multiproduct produced by cost differential in separate regions can achieve substantial economies of scale in transmission links to connected regional systems. Developments in transmission and coordination technology have also led to increased interconnections between regional areas. This in turn has reduced generation capacity requirement and provided a more economical mix of regional generation capacity (Joskow and Schmalensee, 1985).

The foundation of the restructured electricity industry was in the competitive generation sector with its diverse production technology. The introduction of a wholesale electricity market facilitates competition in wholesale electricity generation and trade. The wholesale electricity market is also known as a pool where electricity output from generators is pooled and then scheduled to meet demand. The wholesale electricity market also ensures that wholesale buyers and sellers have open access to the transmission and distribution networks at regulated charges (Roarty, 1998). The pool itself does not buy or sell electricity, rather the pool is a financial settlement system where generators are paid for the electricity they provide to the pool, and retailers and end-users pay for their consumption. The payments into the pool must accordingly balance the payments out of the pool. The method through which payments are balanced depends on the operation of the pool mechanism. The pool mechanism, irrespective of the pricing regime, provides incentive for generators to be more competitive, with the aim to lower wholesale electricity prices for the end-users (NEMMCO, 2005a).

While the pool operate essentially as a physical spot market for electricity, the majority of transactions is covered by hedge contracts between generators, retailers and large consumers to manage the risks of extraordinary levels of volatility in spot prices. A one-way contract guarantees that the consumer will never pay more than the agreed strike price, while a two-way contract provides a hedge for both the consumer and supplier (Wolfram, 1999). Different forms of hedge contracts can provide market participants with a flexible mechanism to ensure future stable electricity prices.

In terms of distribution, all end-use customers prior to electricity reform could only purchase power from distributors within their locale. To stimulate competition in this sector, initially large consumers (industrial users) were permitted to purchase power from electricity suppliers of their choice. This initiative will eventually become available to all consumers including residential customers.

The process of deregulation has also altered the composition of ownership of the generation, transmission and distribution sectors. It began by privatising the generation sector with the sale of its generation assets. The main reasons for privatisation are to encourage competition among regional markets and to promote improvement in price and service quality to electricity consumers.

The restructuring of the electricity industry in Australia began in the early 1990s, starting with the separation of the generation, transmission, distribution and retail components. In July 1991, the eastern Australian states established a National Grid Management Council to organise the most efficient, economic and environmentally sound development of the electricity industry with the principal goals being to deliver cheaper electricity and to promote a more rational use of the nation’s resources. In June 1993, the Council of Australian Governments (COAG) declared a firm commitment to have the necessary changes in place to allow the implementation of a competitive electricity market from 1 July 1995 (Gallaugher, 2004). These reforms led to industry restructure, in particular the separation of generation, transmission and distribution and the foundation of a National Electricity Market (NEM) in the eastern and southern states. In April 1995 these reforms were reaffirmed and extended under the National Competition Policy (NCP) (Australia Bureau of Statistics: Year Book Australia, 2002).

The very gradual move to an integrated national system was predated by substantial reforms on a state-by-state basis, including the unbundling of generation, transmission and distribution and the commercialisation and privatisation of the new electricity companies, along with the establishment of the wholesale electricity spot markets (Dickson and Warr, 2000). For example, the wholesale market for electricity in Victoria and New South Wales commenced as early as 1994 and 1996, respectively, though it was not until 1998 that the wholesale market for electricity began in Queensland.

## 2.3 The National Electricity Market

The principal goals of the NEM are to promote competition and efficiency in the production and consumption of electricity; to encourage flexibility and choice of suppliers to customers; and to ensure no discrimination on the basis of supply technologies or on the location of customers and suppliers (ABARE, 2004). The NEM began operating as a wholesale market for the supply of electricity to retailers and end-users and currently comprises electricity generators in the eastern state electricity markets of Australia operating as a nationally interconnected grid. The member jurisdictions of the NEM thus include the three most populous states of New South Wales [including the Australian Capital Territory (ACT)], Victoria and Queensland along with South Australia. The only non-State based member that currently provides output into the NEM is the Snowy Mountains Hydroelectric Scheme. The Snowy Mountains Hydroelectric Scheme is regarded as a special case owing to the complexity of arrangements underlying both its original construction and operating arrangements involving both the state governments of New South Wales and Victoria, as well as the Commonwealth (federal) government.

Each state in the NEM initially developed its own generation, transmission and distribution network and linked it to another state's system via interconnector transmission lines (Truskett, 1999). However, each state's network was (and still is) characterised by a very small number of participants and sizeable differences in electricity prices were found. The foremost objective in establishing the NEM was to provide a nationally integrated and efficient electricity market, with a view to limiting the market power of generators in the separate regional markets (for the analysis of market power in electricity markets see Brennan and Melanie, 1998; Joskow and Kahn, 2002; Wilson, 2002; Robinson and Baniak, 2002 and Tamaschke et al., 2005).

On 2 April 2006, the island state of Tasmania became a member of the NEM with the completion of the Basslink interconnector, which links Tasmania's electricity supply industry with that of the mainland. The generation companies in Tasmania are now able to submit bids to the NEM (NEMMC0, 2006). Of the member jurisdictions, the largest generation capacity is found in New South Wales, followed in descending order by Queensland, Victoria, South Australia and Tasmania as illustrated in Figure 2.3.

**FIGURE 2.3** ***Total Energy Sent Out 2003 - 2004***

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Source: National Electricity Market Management Company Limited (2005a).

The remaining Australian states of Western Australia along with the Northern Territory are unlikely to participate in the NEM in the foreseeable future. This is due to the economic and physical aspects of interconnection and transmission augmentation across such geographically dispersed and distant areas.

At present, the NEM supplies electricity to eight million Australian customers on the interconnected national grid that stretches more than 4000 km from Port Douglas in Queensland, through New South Wales, the Australian Capital Territory, and Victoria to Port Lincoln in South Australia (NEMMCO, 2003c). The majority of commercial, industrial and residential customers is granted the supplier of their choice and in some cases they can deal directly with the generators (ABARE, 2004). Peak electricity demand is highest in New South Wales, followed by Victoria, Queensland and South Australia. In terms of net aggregate capacity and demand, New South Wales, Queensland, South Australia and the Snowy are potentially overall net exporters of electricity while Victoria is a net importer. Some $7 billion of energy is traded through the NEM yearly within these jurisdictions, with weekly trades of up to $500 million (NEMMCO, 2005b).

The NEM currently comprises more than seventy registered participants within the five member jurisdictions which fall into six categories based on the role they perform in the market. Some participants fill more than a single role within the NEM and therefore belong to more than one category. The categories are: generators; Distribution Network Service Providers (DNSP); market customers (including both electricity retailers and end-use customers); Transmission Network Service Providers (TNSP); Market Network Service Providers (MNSP) and traders.

The NEM 1, phase 1, began in May 1997 with a limited interstate competitive market between New South Wales and Victoria, enabling joint dispatch and pool price setting. The NEM became fully operational in December 1998, including 60 entities in New South Wales, the Australian Capital Territory, Victoria, Queensland, South Australia (and eventually Tasmania with the completion of Basslink) (Roarty, 1998). The NEM is responsible for a common wholesale market serving the interconnected jurisdictions. It also operates a single controller dispatching generators in the connected jurisdictions. The NEM monitors the customer entitlements to purchase electricity from the wholesale market or under contract with a supplier of their choice. The NEM performs a market settlement role which handles spot and forward trading and the contractual requirements of a wholesale electricity market (NEMMCO, 2004).

In terms of electricity generation, the NEM relies heavily on fossil fuels. In New South Wales, Queensland and Victoria electricity production is almost entirely coal-fuelled, while there are gas and wind-powered stations in South Australia. Hydroelectricity plants operate in the Snowy Mountains region. Generators may be privately or publicly owned and fall into four categories according to their obligation to participate in the NEM. These are: market generators (generators whose entire output is sold through the NEMMCO spot market), non-market generators (generators whose entire output is sold directly to a local retailer or customer outside the spot market system), scheduled generators (individual or groups of generators with a capacity rating over 30 megawatts (MW), and whose output is scheduled by NEMMCO's dispatch instructions) and non-scheduled generators (individual or groups of generators with a capacity rating of less than 30 MW). All generators or groups of generators with a capacity rating of 5-30 MW must register with NEMMCO (IEA, 2001).

### 2.3.1 Operation of the National Electricity Code (NEC), the National Electricity Code Administrator (NECA) and the National Electricity Market Management Company (NEMMCO)

The NEM was developed and operates under a number of legislative agreements, memoranda of understanding and protocols between the participating jurisdictions. They include a mechanism for uniformity of relevant electricity legislation across states, implementation of the National Electricity Code (NEC) and the creation of the National Electricity Code Administrator (NECA) and the National Electricity Market Management Company (NEMMCO) to control and implement the NEM.

The NEC is responsible for the market rules which apply to market operations, power system security, network connections and access and pricing for the network services in the NEM. The code was derived from wide-ranging consultation between governments, the electricity supply industry and electricity users as a part of the government-driven deregulation agenda. NECA is the organisation charged with administering the NEC. This entails monitoring participant compliance with the Code and raising Code breaches with the National Electricity Tribunal (IEA, 2001). Other roles of NECA include managing changes to the NEC and establishing procedures for dispute resolution, consultative, and reporting procedures (NEMMCO, 2001). NECA also established the Reliability Panel in 1997, in order to “determine power system security and reliability standards, and monitor market reliability” (IEA, 2001).

The market rules that govern operation of the NEM are embedded in the NEC, which was developed in consultation with government, industry and consumers during the mid-1990s. NEMMCO (2001: 4) summarises the rationale for the thoroughness of the NEC:

> The rules and standards of the Code ensure that all parties seeking to be part of the electricity network should have access on a fair and reasonable basis. The Code also defines technical requirements for the electricity networks, generator plant, and customer connection equipment to ensure that electricity delivered to the customers meets prescribed standards.

The implementation of the NEC required authorisation by the Australian Competition and Consumer Commission (ACCC). Any changes to the NEC are also under ACCC control. Born from the Hilmer microeconomic reforms of the 1990s to create a more competitive environment for government enterprises, the ACCC is the Australian body aimed at enforcing competition law. To this effect, the ACCC is responsible for administering the Trade Practices Act (1974), which was augmented under the National Competition Policy (NCP) reforms to facilitate access arrangements to network infrastructure and the addition of competitive neutrality provisions, which ensure there can be no discrimination between public and private service providers. Asher (1998) highlights the key change to the Trade Practices Act (1974) under the National Competition Policy reforms as "establishing a third party access regime to cover the services provided by significant infrastructure facilities" (facilities not economically feasible to duplicate and where the access arrangements would be necessary to promote effective competition in upstream or downstream markets).

In addition to the administration of this role in regard to market infrastructure, the ACCC is the organisation responsible for the regulation of the transmission network component of the Australian Electricity Supply Industry. Of the various facets that this role encompasses, transmission pricing is the most prominent. This is managed by the ACCC on a revenue cap basis, in an attempt "to constrain monopoly pricing while allowing the business owners a rate of return sufficient to fund network operation and expansion" (ACCC, 2000: 8). In brief, the ACCC's price cap methodology can be described as follows (IEA, 2001: 137):

> The revenue of transmission companies is regulated on the basis of an adjusted replacement value of the assets, known as deprival value, and its weighted cost of capital. The maximum annual revenue allowed to

> transmission is subject to a CPI-X price cap, fixed for a period of at least five years, that reduces transmission charges over time in real terms.

The transmission-pricing role is carried out in conjunction with a service reliability protocol, to promote quality of service. As noted, changes to the NEC affecting transmission or any other aspect of the market must be authorised by the ACCC. As such, the ACCC is responsible for the evaluation of changes to market operations. It is the role of NEMMCO to implement and administer changes to market operation.

In 2004, under the reform initiatives of the Ministerial Council on Energy and the Council of Australian Governments Energy markets study, two new statutory bodies were established: The Australian Energy Market Commission (AEMC) and the Australian Energy Regulator (AER) (NEMMCO, 2004). These replace NECA for administration of Code provisions since the commencement of the NEM. The ACCC is not only responsible for the administration of the Trade Practices Act but also continues to approve changes to the Code and set pricing levels for transmission services until the new arrangements are in place. The AEMC is to carry out the primary functions performed by NECA (including Changing the Code) and eventually other functions performed by the Gas Pipeline Advisory and The Gas Code Register. The AER is responsible for the regulation of electricity transmission and in the future also gas transmission and electricity and gas distribution and retail regulation (other than retail pricing). The aim of the new structure is to streamline decision making, improve accountability and remove duplication of regulatory processes. It is constructed to facilitate an appropriate balance between development and implementation of market rules and also industry regulation and general competition regulation (NEMMCO, 2004).

National Electricity Market Management Company Limited (NEMMCO) was established in 1996 to operate and manage NEM, to develop the market and continually improve its efficiency. NEMMCO’s role is to manage the spot market and to centrally coordinate the dispatch of electricity from all generators to continuously balance supply and demand. It also is responsible for maintaining power system security. It operates under Corporation Law on a break-even basis by recovering cost of operating the NEM and running the organisation with fees levied against market participants. NEMMCO manages the market and power system from two locations in different states. Both centres operate continuously and must have identical communication and information technology systems and the entire NEM selected regions can be operated from either or both centres. This arrangement provides a means of managing the risk of loss of supply from natural disaster or unpredictable events. This provides NEM with the flexibility to react quickly to dramatic changes in the market or power system. The functions and scope of NEMMCO are (NEMMCO, 2003c: 5):

> NEMMCO administers and operates a competitive wholesale electricity market where around 165,000 gigawatt hours (GWh) of electricity is traded annually. The value of this wholesale electricity varies considerably [and] in previous years, has been approximately $6 billion.

The operating experience and accumulation of sound knowledge of NEMMCO since its inception in 1998 enables it to pursue other initiatives to enhance NEM's efficiency by offering a range of new and improved services to meet the changing needs of its consumers. NEMMCO has been working with NEM jurisdictional regulators on amending the NEC to bring about greater harmonisation in the energy market across jurisdictions (NEMMCO, 2003c).

### 2.3.2 Australian Wholesale / Spot Electricity Market and Spot Price

The National Electricity Market Management Company (NEMMCO) operates the wholesale market for electricity trade between generators and retailers (and also large consumers). From an operational perspective, output from generators is pooled in the wholesale electricity market or commonly known as the 'pool', then scheduled to meet demand. The IEA (2001: 134) summarises the core elements as follows:

> The National Electricity Market is a mandatory auction in which generators of 30 MW or more and wholesale market customers compete. Generators submit bids consisting of simple price-quantity pairs specifying the amount of energy they are prepared to supply at a certain price. Up to ten such pairs can be submitted per day. In principle, these bids are firm and can only be altered under certain conditions. Generator bids are used to construct a merit order of generation. Customer bids are used to construct a demand schedule. Dispatch minimises the cost of meeting the actual electricity demand, taking into account transmission constraints for each of the five regions

> in which the market is divided…There are no capacity payments or any other capacity mechanisms.

The two key aspects required for the pool to operate are a centrally coordinated dispatch mechanism and operation of the ‘spot market’ process. As the market operator, NEMMCO coordinates dispatch to “balance electricity supply and demand requirements” (NEMMCO, 2001: 3), which is required because of the instantaneous nature of electricity, and the spot price is then “the clearing price (that) matches supply with demand” (NEMMCO, 2001: 3).

Electricity pools have several defining characteristics: how the pool determines the ‘spot’ price is perhaps the most fundamental. The IEA (2001: 79) summarises the methodological alternatives:

> In most existing pools, pool purchasing prices and scheduled supply are set by auction some time in advance of physical delivery. Pool selling prices are established by adding the costs of imbalances, ancillary services, and possibly other demand related charges such as capacity payments to the pool purchasing price. Since prices are determined from scheduled supply and demand, these are known as *ex ante* pools. Alternatively, there are *ex post* pools, like the Australian National Electricity Market, in which prices are determined *ex post* from actual generator schedules and demand. In an *ex post* pool, the pool purchasing and selling prices coincide.

### 2.3.3 Setting the Spot Price

The pool operates as a spot market or more precisely a day ahead market where each day is partitioned into 48 half-hour intervals. For each half-hour, the generators detail the quantity and price at which they are willing to supply to the pool. The bids are stacked in ascending price order. Generators starting at the least cost are scheduled to meet demand. A single spot or pool price is the average of the six dispatch prices and covers all purchases and sales in that half-hour.

The pool rules dictate that generators in the NEM with a capacity greater than 30MW are required to submit bidding schedules (prices for supplying different levels of generation) to NEMMCO on a day before basis. Separate capacity schedules are submitted for each of the 48 half-hour periods of the day. As a result, the industry supply curve (also called a bid stack) may be segmented to a maximum extent of ten times the number of generators bidding into the pool. NEMMCO determines prices every five-minutes on a real time basis. This is achieved by matching expected demand in the next five-minutes against the bid stack for that half-hour period. The price offered by the last generator to be dispatched (plant are dispatched on a least-cost basis) to meet total demand sets the five-minute price. The price for the half-hour trading period (pool or spot price) is the time-weighted average of the six five-minute periods comprising the half-hour trading period. This is the price generators receive for the actual electricity they dispatch into the pool, and is the price market customers pay to receive generation in that half-hour period.

### 2.3.4 Scheduling and Dispatching Generators

The scheduled generators are required to submit to NEMMCO offers that indicate the volume of electricity that they are prepare to produce for a specified price. There are three types of bids. First, daily bids are submitted before 12:30pm on the day before supply is required. Second, re-bids can be submitted until five-minutes prior to dispatch. In a re-bid only the volume of electricity in the original bid can be changed and the offered price cannot be changed. Third, default bids are standing bids that apply where no daily bids have been made. These bids are of a 'commercial-in-confidence' nature and reflect the base operating levels for generators (NEMMCO, 2004).

There is a separate spot price for each trading interval in each region of the NEM. The price of electricity between regions can vary depending on the limitations of the capacity of the interconnectors and the reliance on different fuel sources of local supplies where gas is a more expensive fuel than coal or water. In 2003, the average spot price was less than $40/MWh for 90 percent of the trading intervals across all NEM (NEMMCO, 2004: 14). ABARE (2004: 33) illustrates the reduction in wholesale spot prices for each state over time:

> Wholesale spot prices for the 2003-2004 year averaged $31/MWh (megawatt hour) in Queensland; $37/MWh in New South Wales; $27/MWh in Victoria; and $39/MWh in South Australia.. Compared with the first full year of the market in 1999-2000, these prices represent a reduction of around 40 per cent in Queensland and South Australia. Prices in Victoria have fallen for the third consecutive year; while in New South Wales prices have remained steady since 2001-2002.

An illustration of spot market pricing in the NEM is drawn from NEMMCO (2004). Table 2.1 contains offer prices for six generators (in $/MWh) and demand information (in MW) for the six five-minute dispatch periods in the 12:30pm trading interval. Assuming each of these generators has 100 MW of capacity, Figure 2.4 graphically analyses the least cost dispatch for these five-minute intervals. For example, at 12:05pm total demand is 290 MW and to meet this demand the full capacity of the lowest priced generators 1 ($32/MWh) and 2 ($33/MWh) and most of the capacity of generator 3 ($35/ MWh) is required. The marginal price for this five-minute interval is then $35/MWh. This information, along with the remaining five-minute intervals until 12:30pm, is tabulated in Table 2.2, which shows the marginal price for each five-minute interval as a result of the plant dispatch mix, which is primarily dependant on the level of demand. The spot price for the 12:30pm trading interval is the average of these six five-minute marginal prices.

**TABLE 2.1** ***Generator Offer Prices and Total Electricity Demand per Half-Hour***

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Source: National Market Management Company Limited (2004).

The spot pricing procedure, while bringing balance between supply and demand, can also expose participants to significant volatility. This is owing to the dependence of the pool process on generator bidding strategies (for instance, Brennan and Melanie (1998) highlight the potential for holders of large generating portfolios to bid non-competitively in order to exercise market power) and the impact of the complex interaction of supply and demand factors on pricing. As such, the spot price can be volatile, leading to significant financial exposure. The occurrence of various phenomena in the NEM has caused instances of high spot prices, and in some cases the maximum spot price cap for the NEM or Value of Lost Load (VOLL) has been

**FIGURE 2.4** ***Least Cost Dispatch and Generator Utilisation***

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Source: National Market Management Company Limited (2004).

**TABLE 2.2** ***Dispatch of Generation and Spot Price Calculation***

| Graph point price | Dispatch $/MWh | Time demand | Total (MW) | Scenario |
|---|---|---|---|---|
| Point A | 35 | 12:05pm | 290 | Generators 1 & 2 are fully utilised. Generator 3 is partially utilised. |
| Point B | 37 | 12:10pm | 330 | Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised. |
| Point C | 37 | 12:15pm | 360 | Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised. |
| Point D | 38 | 12:20pm | 410 | Generators 1,2, 3 & 4 are fully utilised. Generator 5 is partially utilised. |
| Point E | 38 | 12:25pm | 440 | Generators 1,2, 3 & 4 are fully utilised. Generator 5 is partially utilised. |
| Point F | 37 | 12:30pm | 390 | Generators 1,2 & 3 are fully utilised. Generator 4 is partially utilised. |

The spot price is calculated as: ($35/MWh + $37/MWh + $37/MWh + $38/MWh + $38/MWh + $37/MWh) / 6 = $37/MWh

Source: National Market Management Company Limited (2004).

triggered. The maximum spot price of $10,000/MWh is the price automatically triggered when NEMMCO allows network providers to reduce supply in order to keep the balance of supply and demand (NEMMCO, 2004).

Events in the past, that have had a tendency to drive NEM prices toward the upper end of the price spectrum, are of three types. First, prices can increase dramatically when a generation plant ‘trips’ or ‘falls over’, rendering it inoperable and forcing the plant’s contributed capacity to be removed from the bid stack. This is particularly the case if the plant provides base-load output. Secondly, abnormal environmental temperatures drive demand up as customers increase demand for cooling or heating technology. Higher demand requires more generation to balance the system, which means plants bidding in at a higher price level on the least-cost merit order are sequentially dispatched to meet the additional demand (ABARE, 2002). Third, technical constraints or faults with the systems design can also lead to higher prices. These three instances combined to cause an electricity supply crisis for Victoria in February 2000, as profiled by the IEA (2001: 123):

> The Victorian outages reflected a combination of unusual circumstances, including an industrial dispute, which had taken around 20 per cent of generating capacity off line, two unplanned generator outages, and an extremely high peak demand caused by a heat wave across southeastern Australia. The situation was exacerbated by Victorian government intervention to introduce a price cap and establish consumption restrictions, which prolonged the shortages and distorted market responses…The mandatory consumption restrictions introduced by the Victorian government over six days lowered demand in Victoria and had the perverse effect of electricity flowing from Victoria into New South Wales and South Australia while the restrictions were in place.

The illustration of NEMMCO’s dispatch and spot pricing methodology highlights the inherent volatility of the spot price, which can lead to large variations in financial exposure. This is owing to the dependence of the pool process on both generator bidding strategies and the impact of the complex interaction of supply and demand factors on pricing.

So far the generators offer or ‘bid’ prices are illustrated for the calculation of the spot price or the system marginal price (SMP). The price paid to generators per MWh in the relevant half-hour is referred to as the pool purchase price (PPP) and is defined as: PPP = SMP + CC where CC is the capacity charge. The capacity charge is an incentive to encourage generators to have available capacity in case of unexpected demand or plant outages that could threaten the integrity of the generation system. The capacity charge is also made to generators on the basis of the quantity (in MW) of their bid to the pool irrespective of the capacity dispatch in the pool. The capacity charge is defined as: CC = LLOP × (VOLL – SMP) where LLOP is the loss of load probability and VOLL is the value of lost load. The VOLL is the cost per MWh that customers pay to secure an uninterrupted power supply. In Australia the VOLL is set at $10,000/MWh which is extraordinarily high as compared to say the US at $US1,000/MWh ($A1,430/MWh) (Booth, 2004). LLOP for each half-hour is the probability of creating interruptions in power supply when capacity is insufficient to meet demand. LLOP is a decreasing function of the expected amount of excess capacity for each half-hour within a given day. A lower LLOP will produce a lower CC payment per MWh to generators (Wolak, 2000).

### 2.3.5 Role of Interconnectors

Historically, each state in the NEM developed its own transmission network and linked it to another state's system via interconnector transmission lines. Power is transmitted between regions to meet energy demands that are higher than local generators can provide, or when the price of electricity in an adjoining region is low enough to displace the local supply. The scheduling of generators to meet demand across the interconnected power system is constrained by the physical transfer capacity of the interconnectors between the regions. When the limit of an interconnector is reached, NEMMCO schedules the most cost-efficient sources of supply from within the region to meet the remaining demand. For example, if prices are very low in Victoria and high in South Australia, up to 500 MW of electricity can be exported to South Australia across the interconnector. Once this limit is reached, the system will then use the lowest priced generators in South Australia to meet the outstanding consumer demand.

The limitations of transfer capability within the centrally coordinated and regulated NEM are one of its defining features. Queensland became part of the NEM in July 2000 with the completion of the interconnector Directlink, which can export and import 180 MW to and from New South Wales. In February 2001, interconnection between Queensland and New South Wales was considerably strengthened with the introduction of the Queensland and New South Wales Interconnector (QNI) where Queensland can export 950 MW to and import 700 MW from New South Wales. New South Wales can export 1150 MW to the Snowy and import 3000 MW from the Snowy. Victoria can import 1900 MW from the Snowy and 420 MW from South Australia and export 1100 MW to the Snowy and 680 MW to South Australia (as illustrated in Figure 2.5). The greatest transfer capacity is between Snowy to New South Wales and Snowy to Victoria, that is, Snowy is a generation region that exports most of its power to other regions. New interconnectors are being commissioned and upgrades to existing interconnectors are continually being reviewed (IRPC, 2003). There is currently no direct connector between New South Wales and South Australia and Queensland is only connected directly to New South Wales.

The interconnectors in NEM can be regulated or unregulated. A regulated interconnector is an interconnector that has passed the ACCC devised regulatory test. A regulated interconnector receives a fixed, annual revenue based on the value of the asset and set by ACCC irrespective of usage (NEMMCO, 2004). The revenue is collected from the consumer’s electricity bill as part of the network charges. An unregulated (market) interconnector is not required to meet the ACCC regulatory test (Roberts, 2003). Revenue of unregulated interconnectors is obtained by trading on the spot market, buying energy in a lower price region and selling it in a higher price region.

Presently, Directlink is an unregulated interconnector operating between Queensland and New South Wales. On 2 September 2002, Murraylink, between Victoria and South Australia, was completed as an unregulated interconnector but in the following year it successfully applied and was granted regulated status by the ACCC. A proposed construction of 330 km of high voltage transmission line, Riverlink, between western New South Wales to north east South Australia was instigated by an independent review. The review suggested that this new link would be significantly cheaper than building and operating a new power station. Six months later the South Australian Government abandoned plans to build Riverlink as NEMMCO advised that the interconnector was not justified and could have an adverse effect on the sale price of other generators (Rann, 1998: 24). Another unregulated interconnector is Basslink which joins Tasmania to the NEM. The unregulated interconnectors operate side by side with the regulated ones. The regulated interconnection reduces the price differentials between jurisdictions and the unregulated interconnectors require price differentials to survive (Roberts, 2003).

**FIGURE 2.5** ***Interconnectors in the NEM***

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Source: National Market Management Company Limited (2003b).

The illustration of NEMMCO’s dispatch and spot pricing methodology highlights the inherent volatility of the spot price, which can lead to large variations in financial exposure. This is because the end-users’ price is fixed and the generation costs vary according to time-of-day and seasonal factors. This is also owing to the dependence of the pool process on generator bidding strategies and the impact of the complex interaction of supply and demand factors on pricing. Further, while the appropriate regulatory and commercial mechanisms do exist for the creation of an efficient national market, and these are expected to have an impact on the price of electricity in each member jurisdiction, the complete integration of the five separate spot electricity markets has not yet been realised. In particular, the limitation of the interconnectors between the member jurisdictions suggests that for the most part the regional spot markets are relatively isolated, particularly in Queensland and South Australia. Nevertheless, the Victorian electricity crisis is just one of several shocks suggesting that spot electricity pricing and volatility in each Australian electricity spot market is potentially dependent on pricing conditions in the several other markets.

It is the formation of the pool or wholesale electricity market that has produced the inherently volatile spot price in the regional Australian markets. This situation has protracted quantitative modelling of the unique characteristics of the spot electricity pricing and the research papers are included in Chapters 4 to 8.

### 2.3.6 Financial Risk Management and Hedging Contracts

One of the main outcomes of economic reform in the electricity industry is that spot prices are set by the pool at the equilibrium prices determined by continuous exchanges between supply by generators and demand by suppliers selling electricity to consumers. These deregulated prices have been characterised as being relatively volatile when compared with financial markets and other commodity markets. Deregulation has introduced elements of uncertainty in spot electricity prices. To manage the potential volatility in the spot price in the electricity industry, financial risk management, derivative or hedge contracts can be appropriately implemented. Since September 1997, the more mature deregulated electricity markets such as New South Wales and Victoria have had futures and options markets where electricity futures contracts are traded in the Sydney Futures Exchange (2005).

The agreements between the generators and market customers create the hedge contracts that operate independently of both markets and NEMMCO's administration. These can be long or short-term contracts that set an agreed price or strike price for electricity traded through the pool (NEMMCO, 2004). Hedge contracts are not factored into the balancing of supply and demand in the market and are not regulated in the Code. Under a standard hedge contract, the players are willing to exchange cash against the spot price outcome in the market. Figure 2.6 illustrates a hedge contract where two participants agree to purchase a specified quantity of electricity at a set a price or the agreed strike price, say, \$40/MWh (NEMMCO, 2005a). If the spot price is lower than the strike price, the customers pay the generators the difference between the spot price and strike price. If the spot price is \$21/MWh then the customers pay the generators \$19/MWh. Conversely, if the spot price is above the agreed strike price, the generator pays the market customer the difference required to purchase electricity from the pool.

**FIGURE 2.6** ***Hedge Contract in the NEM***

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Source: National Market Management Company Limited (2005a).

Hedge contracts allow customers to take advantage of the low strike price to manage the risk of high spot price. To better manage the financial risk of spot electricity price, a body of sophisticated time series modelling techniques is established to assess and forecast the volatile spot price. This thesis is primarily motivated by these advanced time series methodologies to capture the unique dynamics of the spot price created by the development of a deregulated electricity industry.

### 2.3.7 The Retail Electricity Market

The retail market purchases electricity from the wholesale market to sell to the end-users or customers namely industrial, commercial and residential customers. The role of the retailers is to bill the customers for the electricity consumed from the wholesale market and also the distribution levies charged by the distributors. Those customers purchasing electricity directly from the pool also have to pay distribution charges directly to the distributor. There are two types of customers in the retail market: franchise and contestable.

Prior to market reform, all customers were franchise customers where electricity could only be purchased from distributors within their location. Initially, large consumers including heavy industry and smelters using more than 40 GWh per annum were eligible to choose their own suppliers. This was followed by customers using more than four GWh per annum, later reduced to 750 MWh per annum and 160 MWh per annum. Ultimately the plan is that all customers including domestic consumers can choose their own electricity supplier.

A contestable customer in the NEM is permitted to purchase electricity from a supplier of their choice, irrespective of from where the electricity is sourced (NEMMCO, 2004). Each state has its own time-frame for its customers to move to full retail contestability. By 2005, over one million contestable customers out of 6.4 million have moved to a supplier of their choice (NEMMCO, 2005a). Presently, domestic customers in all states in the NEM with the exception of Queensland are contestable customers. Until all customers especially the small domestic users have available information on prices from power suppliers including the wholesale electricity market, they will be unable to make informed choices about preferred suppliers. The transfer of end-users large and small from franchise to contestable customers will ultimately impact on the price and volatility of the regional spot electricity markets, hence there is a need to provide better models and forecasts for market participants.

## 2.4 Ownership of the Deregulated Market Structure in the NEM

The pace of change in ownership of the deregulated electricity industry varies considerably in each state. With the disaggregation of the single entity monopoly, many of the electricity businesses became corporatised. Victoria and South Australia were more progressive in their restructuring by fully privatising large components of their electricity industry in the late 1990s (Roberts, 2004). In New South Wales and Queensland almost all of the electricity industry remains government owned.

The next section aims to characterise the market structure ownership of the five electricity industries on a state-by-state basis, starting with the state that led electricity reform in Australia, Victoria, then South Australia, New South Wales, Snowy Mountain Hydroelectric Scheme and finally Queensland. The eastern states approached the ownership restructuring process by separation of some electricity functional divisions such as generation, transmission, distribution and retailing with the goals of improving competition, increasing efficiency and lowering prices for all consumers.

### 2.4.1 Victoria

Prior to deregulation, the Victorian Electricity was a state government-owned monopoly, trading as the State Electricity Commission of Victoria (SECV). In 1993, the Victorian Government proposed plans to disaggregate the State Electricity Commission of Victoria and moved generation, transmission and distribution into three separate operating entities. Between January 1994 and January 1995, the three separate entities were formed and corporatised. The corporatised entities from disaggregation consist of seven generation companies, one transmission company, five distribution companies and a wholesale market operator. Since August 1995, the government has privatised six generation, one transmission and five distribution companies (Evans, 2004).

Generation in Victoria is divided into seven separate entities with five independent commercially viable businesses. The first generating entity consists of Loy Yang A with a capacity of 2000 MW. In 1997, Loy Yang A power assets were sold to Horizon Energy, a US firm, so it is now 25 percent Australian owned. The second generating entity, Loy Yang B, with a capacity of 1000 MW was sold in two stages, 51 percent in 1992, and the remaining 49 percent in 1997 to Edison Mission Energy, a Californian firm. It is wholly overseas owned. The third generating entity formed by Hazelwood with 1600 MW capacity and Morwell an open cut brown coal mine. In August 1996, 52 percent of Hazelwood was sold to National Power, UK's largest generating company, and nine percent remains Australian owned. In May 1996, 49.9 percent of the fourth generation entity, Yallourn Energy with a capacity of 1450 MW, was sold to PowerGen International, the second largest English and Welsh generating company, and it remains 40 percent Australian owned. In 1997, the fifth generation power station, Victoria hydroelectric (Southern Hydro), with a 469 MW of capacity, was sold: 50.2 percent to a consortium of Infratil Australia, 22.1 percent to Unisuper and 27.7 percent to Contact Energy of New Zealand. The sixth and seventh power generating plants consisting of Newport and Jeeralang (gas powered station) with 965 MW capacities are now trading as Ecogen Energy which is owned by Generation Victoria (Rann, 1998; Wolak, 2000; Moran, 2004 and Ward and Hodge, 2004).

Most of the power stations in Victoria are largely fuelled by brown coal from the LaTrobe Valley with the remaining generation capacity fuelled by gas turbine and hydroelectric power (Ward and Hodge, 2004). The Victorian generators are very competitive as brown coal deposits are easy to mine. Soft deposits are found close to the surface and do not involve the extensive blasting required to extract New South Wales black coal. Peak demand in the Victorian market is approximately 7.5 GW, and the maximum generating capacity that can be supplied to the market is 9 GW. With this low peak demand, of the five generation firms at least three of the largest base-load generators have sufficient generating capacity to meet at least 80 percent of peak-load. More than 80 percent of the generating plant is brown coal fired, although some capacity does have fuel switching capabilities. Brown coal has very low sulfur and ash content and high moisture content. It also has very low heat content relative to black coal. The brown coal plants are located close to large strip mines. In spite of its low heat content, low cost strip mining makes these plants efficient to operate (Roarty, 1998). These generators are seldomly shut down as they require more expensive fuel sources to restart.

In October 1993, the Victorian Power Exchange (VPX) was formally created to manage the first wholesale electricity business in Australia trading as VicPool. The initial function of VicPool was to provide weekly bids and centralise commitment of power stations (Gallaugher, 2004).

The Victorian transmission grid was operated by GPU Powernet Victoria which owned and maintained the high voltage grid. In early 1998, it was sold to a US energy service company GPU Inc and is now renamed GPU Powernet.

Five (three urban and two regional) geographically based distribution businesses have been established from 18 business units of Electricity Service Victoria and 11 Municipal Electricity Undertakings. These businesses own and operate the low voltage distribution wires and a retail section. In 1995, these five distribution businesses were privatised. First, United energy was sold to a US consortium, UtiliCorp. Second, Solaris Power was sold to a US company, AGL and Energy Initiatives. Third, Eastern Energy was sold to a subsidiary of Texas utility. Fourth, PowerCor was sold to a US company Pacificorp and finally Melbourne's CitiPower was sold to another US consortium, Ent Energy Corp. All five distribution companies were privatised by the end of 1995 (Rann, 1998 and Roarty, 1998).

In December 1994, contestable customers using more than 40 GWh were permitted to purchase power from suppliers of their choice. In July 1995, customers using more than four GWh were granted their choice of suppliers. A year later, customers consuming more than 750 MWh entered the contestable market. In July 1998 the level of electricity consumption was lowered to 160 MWh for consumers to become players. Finally, by January 2002, all remaining customers were given choice of supplier provided there were no significant technical or economic constraints (Roarty, 2004; Gallaugher, 2004 and Quiggin, 2004).

### 2.4.2 South Australia

Prior to deregulation, electricity in South Australia was supplied by a vertically integrated monopoly known as the Electricity Trust South Australia (ETSA). Substantial restructuring commenced in 1993 and by 1995, the ETSA was corporatised and became a holding company, ETSA Corporation, with four wholly-owned subsidiary corporations: ETSA Generation, ETSA Transmission, ETSA Utilities (distribution, network and retail businesses) and ETSA Energy (an energy trading entity incorporating gas) (Roarty, 1998 and Woodward, 2004). In 1997, the generation entity of ETSA Corporation was separated as a new corporation trading as Optima Energy. Optima Energy oversaw the generation of power from a wide range of local generation plants from base-load stations in Port Augusta through to mid-range load and natural gas-fired plant at Torrens Island and a gas turbine peaking plant at Mintaro and Dry Creek (Rann, 1998). The local generators included Flinders Power (Port Augusta), Energy Electricity, Pelican Point, Synergen Power and AGL Power Generation and two wind farms, Tarong Energy Corporation and Babcock and Brown Windpower. In addition to local generation, South Australia also imported approximately one third of its electricity via interconnectors from Victoria. In order to privatise the electricity industry, legislation to enable the sale of Optima by December 1998 and ETAS by December 1999 was introduced into the South Australian Parliament by March 1998. Once the legislation was passed, in August 1999, Flinders Power was leased for 100 years to NRG Energy, a US-based company (Woodward, 2004).

The transmission network ETSA Transmission remained a regulated monopoly. The network connecting South Australia to Victoria was operated and managed by ElectraNet. The NEC established the ACCC as the regulator of pricing and access for transmission networks in South Australia from January 2001. South Australia had been fortunate to be able to import cheap brown coal power from Victoria via the 680 MW interconnector linking South Australia to Victoria and a reverse linkage of 420 MW (NEMMCO, 2003a). South Australia had a very high peak-load especially during the hot summer months with high air conditioner usage (Roarty, 2003). South Australia traded in the Victorian wholesale market via an interconnection to the Victorian transmission grid. The South Australian Government expected power shortages by 1999-2000, so another interstate interconnector, Riverlink, was proposed. In 1998, the government abandoned plans to construct Riverlink based on the advice from NEMMCO that the construction was not justified (Rann, 1998). In August 1997, the state government signed a $1 billion 23-year lease of ETSA's transmission assets to a US-based company, Edison Capital, while ETSA retained operational control over the assets. This lease also involved other generating assets such as the Northern and Playford coal fired plant at Port Augusta, the Leigh Creek coal mine, and a rail linking the coal mine and the power stations (Spoehr, 2004).

ETSA Utilities, a regulated monopoly distribution business, operated and managed the distribution network and was responsible for the transport of power from the transmission network to the end-users. ETSA also oversaw the reliability and safety of the network (Roarty, 1998). In December 1999, the government leased ETSA's distribution network to a Hong Kong-based Hutchson Whampoa group for 200 years (Spoehr, 2004).

In April 1998, the contestable customers using more than 40 GWh per annum were permitted to choose their own suppliers. By July 1998, consumers in excess of four GWh per annum were able to choose where and how to purchase their electricity. In January 1999, industrial and commercial customers using more than 750 MWh per were able to choose their supplier and finally by January 2003, all customers were able to enter the market (Rann, 1998 and Spoehr, 2004).

In 1999, a single retailer, AGL, was given an exclusive licence to sell electricity to small consumers. Two new retailers entered the market to sell electricity to consumers and they found it very difficult to compete with the dominant retailer, AGL (Spoehr, 2004). This trend is contrary to the aims of a deregulated electricity industry.

### 2.4.3 New South Wales

Initially the Electricity Commission of New South Wales controlled the power stations and sold electricity at government determined prices through council owned distributors which owned the poles and wires that transmitted electricity to consumers. In 1992, the Electricity Commission of New South Wales was renamed Pacific Power and restructured into six businesses consisting of three generating groups, one pool trading, one network business and one service unit. In addition, there were 25 separate distribution businesses (McDonell, 2004). The separation of Pacific Power enabled the New South Wales generators and retailers to participate in NEM1 which began in May 1997 and was a trial operation for trading of wholesale electricity between New South Wales (including Australian Capital Territory) Victoria and South Australia. The main feature of the wholesale electricity market rules of Victoria and New South Wales associated under NEM1 was to generate interstate trade where each state retained its own wholesale electricity market (Rann, 1998).

In terms of generation, Pacific Power was restructured to create two additional corporatised generation businesses, Delta Electricity and Macquarie Generation. Delta Electricity with a capacity of 4240 MW – consisting of Mount Piper and Wallerawang (near Lithgo) and Munmorah and Vales Point (Central Coast) – provided 40 percent of New South Wales electricity supplies. Macquarie Generation, with a capacity of 4640 MW – consisting of Baywater and Liddell in the Hunter Valley – provided 40 percent of electricity with a capacity of 4640 MW. Pacific Power's generation also included Eraring Generation on the NSW central coast with a capacity of 3270 MW (Rann, 1998; Roarty, 1998 and McDonell, 2004).

New South Wales is similar to Victoria in having only one transmission business the Electricity Transmission Authority, trading as Transgrid, and is responsible for the control of high voltage systems. Transgrid has one of the largest transmission networks in the world interconnecting the Snowy Hydroelectric Scheme, Victoria and South Australia via Victoria. The Transgrid networks consist of 73 substations and switching stations and approximately 11,500 km of high voltage transmission lines (Rann, 1998).

Since deregulation, the 25 former distribution and retailing businesses have been amalgamated and into six individual businesses, namely Energy Australia, Integral Energy, North Power, Advance Energy, Great Southern Energy and Australian Inland Energy. The distribution companies were corporatised in 1996. The Transgrid network introduced an interim wholesale market and linked the producers to the end consumers (Rann, 1998 and McDonell, 2004).

There are about twenty retailing businesses in NSW including the retail arms of the three generators and six distributors. In addition generators and distributors from other states operate in NSW. Furthermore other NSW retailers buy and sell electricity through the NEM without owning any infrastructure (Roarty, 1998). Few analysts believe that the NSW distribution businesses operate independently of the retailing businesses. This underlies some of the later empirical results.

From 1997, New South Wales progressively deregulated the retail markets. In April 1997, customers using more than 40 GWh per annum were able to choose their suppliers; then in July 1997, customers consuming over 750 MWh; in 1998 customers using more than 160 MWh; and finally by January 2002 all customers were able to choose their own suppliers (Roarty, 2004).

### 2.4.4 Snowy Mountain Hydroelectric Scheme

The Snowy Mountain Hydroelectric Scheme, which is located in southern NSW, is one of the most complex water and electricity projects in the world. It is owned and managed by the Snowy Mountains Hydro-electric Authority (SMHA), established under the Snowy Mountains Hydro-Electricity Power Act in 1947. The Snowy Mountains Council consisting of the Commonwealth, New South Wales, Victoria and the Authority oversaw the storage and release of water, and electricity generation. The Authority essentially generated and sold electricity to New South Wales, Victoria and The Australian Capital Territory on a cost recovery basis (Roarty, 1998).

To conform to the electricity restructuring process, the Commonwealth Parliament in late 1997 passed the Snowy Hydro Corporatisation Act to prepare the Authority to operate as an independent commercial entity. The Snowy Hydroelectric Scheme highly depended on the availability of water for generation. Therefore lengthy periods of drought could reduce the Scheme’s delivery of saleable water and ability to generate electricity. The Snowy Hydroelectric Scheme was corporatised on 28 June 2002. This generation business had transformed into a modern high technology business dealing in complex derivative energy and water products such as insurance contracts to cover other generators’ outages or to generate additional electricity to meet increased demand and to prevent price spikes in the deregulated and real time electricity market.

### 2.4.5 Queensland

In 1995, the Queensland Electricity Commission (QEC) was separated into two government owned corporations. The Queensland Generation Corporation trading as AUSTA Electric was responsible for generation. The Queensland Transmission and Supply Corporation (QTSC), which was responsible for transmission, distribution and retail, was a holding company for eight subsidiaries. The Queensland Electricity Transmission Corporation, trading as Powerlink, was responsible for the state's high voltage transmission network (Roarty, 2004). The remaining seven subsidiaries were responsible for distribution which oversaw the low voltage networks and retailing in their regions.

In December 1996, a special task force, Queensland Electricity Industry Structure Task Force, was established to recommend institutional and regulatory changes to the electricity supply industry to the Queensland Government. The reform strategy aimed at strengthening Queensland's competitive position in the NEM. Queensland began its electricity restructuring in January 1997, which was significantly later than in the other states. The key reform strategies included the separation of the state generator into three independent and competing corporations and retained the seven existing distribution corporations (Roarty, 2004).

In 1997, AUSTRA Electric (formerly Queensland Generation Corporation) became three independent generating corporations, namely CS Energy, Tarong Energy and Stanwell Corporation together with an engineering services organisation AUSTA Energy (Roarty, 2004).

The Queensland Transmission and Supply Corporation, Powerlink, and the seven subsidiaries were established as independent government-owned transmission and supply corporations. These included Capricornia Electricity (CAPELEC), Far North Queensland Electricity (FNQEB), Mackay Electricity (MEB), North Queensland Electricity (NORQEB), South East Queensland Electricity (SEQEB), South West Queensland Electricity (SW Power) and Wide Bay-Burnett Electricity (WBBEC) (Rann, 1998).

In 1998, the seven distribution companies were amalgamated into three retailing corporations. First, Northern Electricity Retail Corporation Pty Ltd (NERC) traded as Omega Energy consisting of Far North Queensland Electricity (FNQEB), North Queensland Electricity (NORQEB) and Mackay (MEB). Second, Central Electricity Retail Corporation Pty Ltd (CERC), traded as Ergon Energy, encompassing Capricornia Electricity (CAPELEC), Wide-Bay Burnett Electricity (WBBEC) and South West Queensland Electricity (SW Power). Third, Southern Electricity Retail Corporation Pty Ltd (SERC), known as Energex, was formed as a wholly state government owned subsidiary of South East Queensland electricity (SEQEB). In February 1998, Ergon Energy and Omega Energy merged trading as Ergon Energy which covered 97 percent of Queensland and became the fifth largest power retailer in Australia (Rann, 1998 and Roarty, 2004). In April 2006, it was announced in the press that the Queensland government intends to privatise the retail arm of electricity supply in the future (Williams, 2006).

In February 1998, customers with power bills of more than 40 GWh per annum were permitted to purchase electricity from generator companies via retailers from an electricity pool. In January 1999, the second group of contestable customers, consuming more than 4 GWh per annum, was able to choose their own electricity supplier. In January 2000, the third stage of competition for those customers, using more than 200 MWh per annum, was able to participate (Roarty, 2004). Residential customers have yet to enter the contestable market.

## 2.5 Concluding Remarks

Electricity plays a vital role in all developed economies, including Australia. However, the Australian economy's reliance on electricity generation, transmission and distribution has for the most part (and in common with most other economies) been largely taken for granted. The overall result has been that until comparatively recently the electricity supply industry has assumed a lesser role in the economic agenda when compared to many other industries. The importance of electricity in Australian economic development has promoted the Australian electricity industry as one of the most important sectors of the Australian economy, with over $86 billion in assets, the electricity industry ranks as one of Australia's largest, making a direct contribution of 1.5 percent of Australia's gross domestic product. Compared with

1989-90, the industry in 2001-02 delivered more electricity (up 45 percent), to more customers (up 26 percent) with less than half the number of employees (ABARE, 2004).

Globally, where electricity restructuring has taken place, it has been the view that competition should take place in the electricity supply industry wherever it is technically feasible. Only those sections of production process most efficiently supplied by a single firm should remain regulated. It is well noted that the generation and retailing sections are where competition can take place. Usually, economies of scale in generation are exhausted well below current levels of industry output. However, assuming that all retailers have equal accesses to the transmission and distribution of network from the wholesale generation market, significant increasing returns to scale are unlikely to exist. Also competition in the transmission and distribution of the supply of electricity would require duplication of the existing network so it is best for these sections to remain as a natural monopoly or regulated to varying degrees. Although privatisation has become an important part of this restructuring process, various countries have either completely privately owned or state-owned or a combination of both to compete in the electricity generation market.

The introduction of the NEM has resulted in sweeping changes in the electricity industry with the generation, transmission and retailing sectors acting as separate businesses. The operational responsibility for the NEM lies with the National Electricity Market Management Company (NEMMCO), which manages the system in accordance with the governing market rules, the National Electricity Code, which is in turn administered by the National Electricity Code Administrator (NECA). The National Electricity Code is granted authority by the Australian Consumer and Competition Commission (ACCC) which must also authorise any subsequent changes to give effect to the code. The illustration of NEMMCO's dispatch and spot pricing methodology highlights the inherent volatility in the spot price, which can lead to large financial exposure. The NEM has intensified price competition in the wholesale electricity market by lowering prices for the deregulated electricity industry but this has also been accompanied by an erratic pattern of price spikes leading to higher price volatility. Price competition has also been introduced in the retail market with progressively large businesses and industries taking advantage of a choice of electricity suppliers and benefiting from large price reductions. Over time the small businesses and residential consumers can also benefit directly as the contestable market expands; and indirectly from the reduction in costs as the electricity markets become more efficient.

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# 3 Literature Review

## 3.1 Introduction

The description of the electricity industry is presented in this section and in the following section; it provides a background which is designed to give guidance as to the areas of the literature that are relevant to this thesis.

Twenty years ago there was essentially no competition within the electricity industry in Australia or anywhere else in the world (Joskow, 2000: 476 and Wolak, 2000: 92). In more recent times, there has been a move towards deregulation on a global scale. The rationale behind the change was a move to a more competitive and efficient power industry. It is believed that a competitive structure is the only way to provide uncertainties such that firms are encouraged to minimise costs and improve quality. On the other hand, it is argued that when different providers of goods and services are intensively engaged in a competitive process, it becomes difficult to ensure that an adequate level of coordination is taking place in order for the industry to benefit from economies of scale which are external to the firms but internal to the industry (Boyer and Robert, 1997). While the latter view has been sufficiently pervasive in the academic debate on whether the move towards a competitive structure is justified, the recent trend suggests that the former view has been more persuasive among those who have been active in policy making with respect to network industries such as electricity. This has induced transformation in the market structure which in turn has motivated studies of newly emerging price and volatility relationships in electricity markets.

With the introduction of competition in the energy market, a wholesale electricity market has been established whereby wholesale or spot electricity prices have become more volatile, thus inaugurating the valuation and management of energy derivatives. Energy producers and users have since embraced the concept of 'risk' whereby they have to hedge their bets against uncertainty in the future by entering into futures and options contracts. Energy has become the most recent market to be governed by derivatives and risk management in financial markets (Pilipovic, 1998; Kaminski, 1999 and Clewlow and Strickland, 2000).

Many empirical studies on energy dynamics have been created to forecast spot electricity prices and ultimately are used to form a basis for the valuation of energy derivatives. The energy industry is the most recent market to enter the derivatives and risk management arena and unlike the financial market, it displays a more complex pricing behaviour.

Fundamentally, there are many differences between the factors that drive the financial markets and those that drive the electricity markets. The financial market is relatively simple with few determinants or forces and can be easily incorporated into quantitative models. The final good for the financial market is presented as a piece of paper or an electronic form that can be easily stored and transferred and is unaffected by weather conditions. The energy markets present a more complex scenario. Energy markets often involve the dynamic interplay between producing and using; transferring and storing; buying and selling – and ultimately burning actual physical products (Pilipovic, 1998). Storage, transportation, technological advances and weather conditions are important factors in modelling spot electricity prices.

The issues of storage, transport, weather and advances in technology play a vital role in the electricity industry. The supply side of the electricity industry concerns not only the storage and transfer of coal but also how to get the coal out of the ground, whereas the end-user is concerned with the consumption of the end product. Residential users require energy for the day to day operations of household activities together with heating in the winter and cooling in the summer. Industrial users require power to maintain continuous operation of their plants and to avoid the high costs of stopping and restarting the process (Pilipovic, 1998).

Each of these market participants, either producers or end-users, deals with different sets of fundamental determinants which in turn will affect electricity pricing behaviour. Some important characteristics underlying the predictable components of power price behaviour are volatility clustering; persistence; mean-reversion; jumps and spikes; and seasonal effects.

It is vital to be able to quantify the predictable components of the spot electricity price. These then can be utilised to calculate the value of the derivative contracts. The risk-adjusted discounted expected value of future electricity contingent payoffs dictates the price for final consumers and these are strongly dependent on the future level of spot electricity prices (Lucia and Schwartz, 2002). It is the aim of this thesis to quantify some of the intrinsic features in the highly volatile spot electricity price.

A body of time series or quantitative techniques has been widely used to measure and understand the price and volatility or risk behaviour of the well-established financial markets. There is a need to extend these time series techniques to capture the more complex behaviour of spot electricity prices. The aim of this chapter is to present the intrinsic spot pricing behaviour and quantitative techniques that can be used to model spot electricity prices. This forms the basis for valuation and management of energy derivatives.

In what follows, some of the issues specific to electricity markets that shape the basis of our modelling approaches are presented.

## 3.2 Stylised Features of Spot Electricity Prices

Some of the fundamental characteristics of the spot electricity price arise because of the non-storability of this commodity where supply has to be instantaneously balanced with demand. Electricity markets represent the extreme case of this storage limitation issue as once the generation plants reach the maximum allowable base-load and marginal capacity, there can be no extra power from that generating plant (Goto and Karolyi, 2003). Excess demand for electricity can be accommodated at prices several times higher than normal price levels. The non-storability problem which causes volatile day-to-day behaviour can be exacerbated by extreme weather/seasonal conditions, or problems with generation plant failures or interconnectors for transferring power. Another interesting characteristic of commodity markets is mean-reversion: that is, how quickly the shocks are dissipated or the supply and demand are returned to equilibrium (Pilipovic, 1998). Similar to the financial markets, the energy market is found to be strong in mean-reversion.

Electricity is a unique and complex industry that operates on a real time network with collaboration and coordination to deliver a vital service. Demand for electricity is inelastic. When consumers are faced with very high electricity prices, they cannot simply switch to a close substitute. Supply is also inelastic (Mount, 1999). New generators and transmission lines cannot be immediately erected. There are several factors that explain the inherently volatile spot electricity prices. The most important one is that once produced, electricity is extremely costly to store. Electricity cannot be physically stored in a direct way whereas the fuels such as water for hydroelectric scheme or coal can be used to generate electricity and can be indirectly stored. As generation and consumption of power have to be continuously balanced, the supply and demand shocks cannot be easily smoothed out by inventory and will have a direct impact on the equilibrium prices.

### 3.2.1 Seasonality

Demand for electricity is influenced by seasonal fluctuations. There are significant differences in the spot prices due to changing climate conditions such as temperature and the number of daylight hours (Bierbrauer et al., 2003). There is a need to differentiate the time-of-day, day-of-week and month-of-year effects on daily spot prices.

Demand for electricity can also fluctuate according to weather conditions within each regional market in the NEM. Recently, in Victoria and South Australia there has been increased conversion to gas for heating in the winter months, thus moving the peak electricity demand to the summer months. Peak electricity consumption is also evident in summer for Queensland because mild winters do not require electricity for the purpose of heating. In New South Wales, maximum electricity consumption can occur in both summer and winter. With increasing domestic air-conditioning, electricity demand is expected to increase significantly in summer.

The systematic behaviour of electricity prices can be explained by periodic patterns of demand arising from seasonal fluctuations (Knittel and Roberts, 2001; Lucia and Schwartz, 2002; Escribano et al., 2002 and Guthrie and Videbeck, 2002).

### 3.2.2 Mean-Reversion

Spot electricity prices also exhibit a certain degree of mean-reversion. A mean-reversion process has a drift term which brings the spot price series back to the equilibrium level. Basically, the spot price series oscillates around the equilibrium price. Every time the stochastic term pushes the spot price away from equilibrium, the deterministic term acts in such a way as to pull it back to the equilibrium position (Pilipovic, 1998). Spot prices are mean-reverting as weather is a dominant factor influencing the equilibrium price, through changes in demand. The cyclical nature of weather conditions tends to pull price back to its mean level (Knittel and Roberts, 2001 and Escribano et al., 2002). Electricity prices exhibit strong mean-reversion which suggests a quicker return of the price from some extreme position such as a price hike or spike to equilibrium; thus extreme price spikes are generally short lived (Bierbrauer et al., 2003 and Huisman and Mahieu, 2003).

### 3.2.3 Volatility, Jumps and Spikes

Volatility is one of the defining characteristics of spot electricity prices. This represents the magnitude of randomness or day to day changes to the spot price over time. At times when supply exceeds demand, electricity is sold at marginal cost. When demand exceeds supply, the electricity price can jump to the VOLL which is $10,000 per MWh (Booth, 2004). Volatility is measured in the stochastic component of most modelling processes. Volatility is an important aspect of spot electricity prices and is also an import input to valuation and risk management (Walls, 1999; Lucia and Schwartz, 2001; Robinson and Baniak, 2002 and Bystrom, 2003).

Supply and demand characteristics and schedules are also responsible for the observed volatility in spot prices. Electricity demand is highly inelastic in the short-run. Electricity is a necessary good therefore customers cannot reduce consumption at times of high demand due to extreme temperature or generator failure. The result is large price hikes or spikes. The characteristics of the supply stack of each market can also contribute to spot price spikes. The pool prices are set by market forces balancing supply and demand. During off-peak periods, generators supply electricity at base-load units produced at low marginal costs. In time of increasing demand or peak-periods, generators with higher marginal costs are stacked in order of rising prices and scheduled into production. The inelasticity of demand to price changes, and the binding transmission capacity, including breakdown of interconnectors between regions at peak times can exacerbate the volatility of short-term spot prices. In markets with steep demand and supply curves, increases in demand result in sharp increases in price (Escribano et al., 2002 and de Jong and Huisman, 2002).

The inherent volatility in spot prices also exhibits persistence. Volatility is persistent, “if today’s electricity return has a large affect on the forecasted variance many periods in the future” (Hadsell et al., 2004). Similar to asset return volatility, periods of high and low volatility tend to cluster over time. The assumption of constant variance is violated for spot price series. The autoregressive conditional heteroskedastic models are devised to take account of the time-varying variances in the spot price series (Knittel and Roberts, 2001; Escribano et al., 2002; Solibakke, 2002; Goto and Karolyi, 2003 and Hadsell et al., 2004).

News innovation may have an asymmetric impact on volatility. The asymmetric volatility responds to negative and positive shocks such that volatility tends to rise in response to ‘bad news’ and fall in response to ‘good news’. Solibakke (2002) and Hadsell et al. (2004) introduce the asymmetric factor to capture the negative and positive news on volatility of spot prices.

Finally the volatility of spot prices depends on the market structure and market power. Where there are only a small number of generators to meet the high levels of demand, generators could exercise market power to limit supply and increase prices.

## 3.3 Modelling Electricity Price Behaviour

Unfortunately, despite the key importance of market pricing within each spot market and the integration of the separate state-based electricity markets within a single national market, very few empirical studies currently exist in Australia or elsewhere concerning the pricing behaviour of the deregulated electricity market. This is important, not only because “…the spot price strongly influences the contract price which, in turn, largely dictates the final price for consumer [but also] because the spot price represents a considerable element of cost for direct purchasers of power, such as large industrial companies” (Robinson, 2000: 527). The short life of the Australian electricity spot market is the most apparent, though not the only, reason. In actual fact, very little work has been undertaken in any context that provides a detailed understanding of electricity price behaviour and almost none using the advanced econometric techniques so increasingly widespread in work on, say, financial markets. The few studies that do exist are especially noteworthy and are presented below.

Electricity supply and demand are subject to economic and business activities and weather conditions. Demand of this essential good is highly inelastic. At times of low demand, electricity is supplied using the base-load units with low marginal costs. At times of high demand during summer and winter months or week days as compared to week-ends, generators at higher marginal costs are scheduled into the pool. Knittel and Roberts (2001), Lucia and Schwartz (2002), Escribano et al. (2002), Guthrie and Videbeck (2002) and Hadsell et al. (2004) have included seasonal factors in their studies.

Further increases in demand due to weather conditions push up prices, as more expensive generators enter the pool. This leads to some degree of mean-reversion in prices. A mean-reversion process has a drift term which brings the time series variable of interest back to the equilibrium level. The stronger the mean-reversion the quicker is the return of the variable from some extreme position away from equilibrium back to it. Studies profiling mean-reversion models include Deng (2000), Knittel and Roberts (2001) and Escribano et al. (2002). Some studies also show the interaction of the degree of mean-reversion with price spikes that can occur after unexpected outages of generators or transmission lines. Deng (2000), Huisman and Mahieu (2003) and Bierbrauer et al. (2003) incorporate jumps, regime switching and stochastic volatility in the mean-reversion models to capture the uncertainty in the load due to forecasting errors.

The move towards liberalisation of the electricity supply industry has lowered electricity prices but has made pricing more volatile, with features of persistence and volatility clustering. The measures of volatility illustrate the degree of randomness or risk in the spot electricity prices and it is an important variable in the valuation of risk management models. Possible models – such as autoregressive moving average (ARMA), autoregressive conditional heteroscedasticity (ARCH) or generalised autoregressive conditional heteroscedasticity (GARCH) processes – allow volatility shocks to cluster and persist over time and to revert to some more normal level and so may offer potentially interesting insights on the volatility observed in the electricity markets. Robinson and Taylor (1998), Knittel and Roberts (2001), Escribano et al. (2002), Solibakke (2002) and Goto and Karolyi (2003) use ARMA and GARCH models to investigate the conditional mean and volatility characteristics of spot electricity markets while Solibakke (2002) and Hadsell et al. (2004) extend the ARCH process to the Exponential ARCH (EARCH) and threshold ARCH (TARCH) processes to take account of asymmetric response in the spot electricity prices.

All the above mentioned studies investigate the intra-relationship of each regional electricity market whereby univariate time series techniques are used to encapsulate the dynamics of spot electricity prices. There are very few studies on the integration or inter-relationship of regional electricity markets (see, for instance, De Vany and Walls, 1999a). These two researchers use cointegration analysis between pairs of regional markets to assess market integration, while Bystrom (2003) applies the constant correlation bivariate GARCH model to the short-term hedging of electricity spot prices with electricity futures.

The literature review is divided into two sections: multivariate versus univariate models to depict the behaviour of the spot electricity prices characterised by several distinguishing features. The multivariate models are employed to capture the inter-relationship among spot electricity markets and how the effects of its own and other markets can be used to forecast the price movement of its own market. Modelling multivariate time series models involving more than one market depends on whether the series are stationary or non-stationary. If the series are non-stationary and an interesting feature concerning the series is cointegration or whether the series move together in the long-term, then cointegration techniques are used. If the series are stationary, regression or GARCH models can be appropriately employed to model the series. The univariate time series models are used to profile the 'stylised facts' or components that explain the intra-relationship of the spot electricity price series itself. All studies in the univariate context are found to be stationary and a family of GARCH and mean-reversion and regime switching models is widely used to investigate the reliability of the underlying price process in forecasting the spot electricity prices.

Since all data used to model spot electricity prices are time series data, it is important to determine initially whether the series is stationary or non-stationary. The result of this test determines the appropriate quantitative methods to assess the dynamics of the series. The study by De Vany and Walls (1999a) finds the electricity pool prices to be non-stationary and hence uses cointegration analysis, while all other studies employ stationary techniques which involve a family of ARCH or GARCH and stochastic processes relating to regression techniques. The stationary techniques encompass two components; the deterministic and stochastic parts. The deterministic part of the stationary quantitative analysis extracts the predetermined information from the spot price thus leaving the volatile components in the residuals. These are then used to capture the volatility or risk of the spot electricity prices. Within the broad scope of modelling spot electricity prices, there are basically three quantitative techniques: cointegration, a family of GARCH models and stochastic models. As detailed in Table 3.1, these include multivariate models (De Vany and Walls, 1999a and Bystrom, 2003), univariate in terms of a family of GARCH processes (Robinson and Taylor, 1998; Knittel and Roberts, 2001; Escribano et al, 2002; Solibakke, 2002; Goto and Karolyi, 2003 and Hadsell et al., 2004) and stochastic models including jumps and mean-reversion and spikes (Deng, 2000; Robinson, 2000; Knittel and Roberts, 2001; Escribano et al., 2002 and Huisman and Mahieu, 2003). Even though most research in terms of modelling the dynamics of electricity markets are summarised in Table 3.1, the section that follows the table discusses some of the well-cited papers in each of the multivariate, univariate and stochastic techniques that have inspired research in the Australian context.

**TABLE 3.1** ***Quantitative Modelling of Spot Prices***

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Helm and Powell (1992) | Analyse pool pricing behaviour with reference to underlying hedging contracts | Daily average pool price in the British electricity supply industry from April 1990 to August 1991 | Log daily average pool price | Log daily demand; dummy variable to take account of structural break when contract for differences a form of options contract expired; lagged log daily demand; and lagged log daily pool price | Dickey-Fuller (DF) and augmented Dickey-Fuller (ADF) stationarity tests; cointegration analysis; and error correction model | The DF and ADF tests on the pool price regressed on demand reveal the non-stationary series are strongly cointegrated even with the inclusion of a dummy variable to take account of structural break. When the lagged price is included, the error correction model exhibits evidence of ARCH effect. |
| Robinson and Taylor (1998) | Use conditional variance to measure the effects of regulatory intervention in 12 UK regional electricity companies | Daily stock price changes in 12 UK regional electricity companies from 10 December 1990 to 11 March 1996 | Stock price changes for conditional mean equation and volatility for conditional variance equation | Two dummies for unexpected interventions by electricity regulator in March 1995 | Autoregressive Conditional Heteroskedasticity process of order one - ARCH(1) | The conditional variance equations indicate that 10 out of 12 regional markets exhibit significant persistence and eight markets show increased volatility after regulatory intervention. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Walls (1999) | Measure volatility of electricity future contracts as future contracts approach maturity | Daily data on electricity futures contracts traded on the New York Mercantile Exchange (NYMEX) for California-Oregon-Border (COB) and Palo Verde Nuclear Switchyard (PV) from 29 March 1996 to 26 November 1996 | Volatility measured by the high/low variance | Model (1) Log of maturity being the number of trading days until the futures contract expires; Model (2) Log of maturity and log of volume being the number of futures contracts traded on the particular day for seven different maturity dates for each market | Philips and Perron unit root test; regression | The volatility and log volume are both stationary. Model (1) shows that the results are consistent with the Samuelson hypothesis that price volatility increases as the future contract approaches maturity. The results of Model (2) illustrate strong evidence of increasing volatility as contract maturity approaches even with the inclusion of volume of trade. |
| De Vany and Walls (1999a) | Examine the behaviour of peak and off-peak electricity spot prices for evidence of market integration | Peak and off-peak daily electricity prices from December 1994 to April 1996 for 11 regional markets in western US | Price of own market | Price of other interconnected market | Augmented Dickey-Fuller unit root test; cointegration analysis between 55 pairs of markets | All electricity series are non-stationary with the exception of one market. All 55 off-peak market pairs are cointegrated, while eighty-seven percent of the peak demand market pairs are cointegrated. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
| --- | --- | --- | --- | --- | --- | --- |
| De Vany and Walls (1999b) | Estimate dynamic equations of wholesale or spot prices over five decentralised state regions | Peak and off-peak daily electricity prices from December 1994 to April 1996 for five regional markets in western US | First difference of spot price | Lagged price of own market | Vector Autoregressive (VAR) models; and Choleski decomposition to identify impulse responses | A larger proportion of peak period shocks than off-peak period shocks transmit from the originating market node to other more distant interconnecting market nodes. The damped responses of the price shocks and the stable forecast errors suggest five regional markets in west US are efficient. |
| Deng (2000) | Examine a broad class of stochastic processes to model the electricity spot prices and how these processes can impact on the value and optimal timing of investment opportunities | US markets | Natural log of spot electricity price and spot price of a generating fuel such as natural gas | Jumps; and stochastic volatility | Mean-reversion; jump-diffusion; and regime-switching | The mean-reversion jump-diffusion models are reliable to model the volatility in the market prices of the traded electricity options in the US markets. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Robinson (2000) | Model the behaviour of spot electricity prices which can influence the contract prices | Daily average pool price from 1 April 1990 to 31 May 1996 for the English and Welsh wholesale electricity markets | Pool purchase price | Pool purchase price lagged one period; and lagged six periods | Autoregressive regression including a non-linear logistic term | The nonlinear model is superior in estimating the pool price behaviour. The estimated parameters imply that prices are less mean reverting the further they deviate from the mean. |
| Wolak (2000) | Forecastability of daily vector of prices in England and Wales; Sweden and Norway; Victoria in Australia; and New Zealand spot electricity markets | Half hourly spot prices for all markets with the exception of hourly prices for the Sweden and Norway electricity market | The mean of all 48 half hour spot prices and the mean of all 24 hourly spot prices for the Sweden and Norway market | Eight lags of this price; and all other half-hourly prices | Autoregressive models; and eigenvalues of the residual covariance matrix from the autoregressive model to forecast the daily pool selling prices | The dynamics of the within-day variation in prices is more complex in the Victorian market, while the Nordic market has the least complexity. The NordPool prices are the most forecastable. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Knittel and Roberts (2001) | Model the degree of persistence, intraday and seasonal effects in electricity prices | Hourly electricity prices from 1 April 1998 to 30 August 2000 for one Californian electricity market | Change in half hourly prices | Demand; time-of-day; day-of-week; and seasonal effects | Mean reversion model; time varying mean reversion; jump diffusion process; univariate Markov process; exponential GARCH (EGARCH) | Electricity prices exhibit a high degree of persistence with a significant relationship between demand, intraday, day-of-week and seasonal effects. The EGARCH model demonstrates a significant inverse leverage effect indicating positives price shocks increase price volatility. |
| Lucia and Schwartz (2001) | Model the predictable component in the dynamics of spot electricity prices and its implications for derivative securities | Daily spot prices from 1 January 1993 to December 1999 for the Norwegian spot electricity market | Log of spot prices for the deterministic component and the random fluctuation for the stochastic component | Demand and seasonal factors for the deterministic component; Brownian motion in the one factor model and the inclusion of a short-term mean reverting component; and a long-term equilibrium price in the two factor model | Diffusion stochastic processes | The seasonal patterns are significant in modelling the dynamics of spot electricity prices with different volatility between the summer and winter seasons and the models exhibit a significant mean reverting diffusion process. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| de Jong and Huisman (2002) | Estimate a model to value options on electricity spot prices to take account of two main features such as mean-reversion and spikes. | Daily spot prices for the Dutch spot market (APX) spanning 2 January 2001 to 30 June 2002 | Daily log returns | Mean-reversion; and regime switching to incorporate jumps and spikes in spot electricity prices | Regime switching model with normal and lognormal spike regimes | The options pricing model can be used to predict an explicit value for the spike component of the value of options on electricity spot prices where spikes have made the sale of options highly risky. |
| Escribano, Pena and Villaplana (2002) | Estimate a general and flexible model to take account of the interaction between jumps, GARCH and mean reversion behaviour of electricity prices | Daily electricity prices in five deregulated markets, namely: Argentina; Australia (Victoria); New Zealand (Heyward); Scandinavia (NordPool) and Spain | Conditional mean and conditional variance | The stochastic component consists of seasonality; mean reversion; jumps | Six nested GARCH models are estimated with the inclusion of sinusoidal functions to capture the deterministic seasonal behaviour. A Poisson distributed random variable takes account of jumps with the possibility of time-dependent intensity in the spot prices | The electricity prices for the five international markets indicate mean-reverting with strong volatility with jumps of time-dependent intensity even after adjusting for seasonality. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Guthrie and Videbeck (2002) | Assess the high frequency electricity spot price dynamics by treating electricity delivered at different half-hour of the day as different commodities | Half-hourly data from two sections: 1 March 2000 to 28 February 2001 and 1 March 2001 to 28 February 2002 for a key New Zealand node | Spot electricity price of each half hour | Lagged prices of its own half-hour and lagged prices of the other half hours; and daily and monthly dummies | Periodic autoregression models (PAR); and state space models | Forty-eight PARs are estimated and the spot price is highly correlated within these markets. The dynamic structure is maintained by introducing restricted number of lags. The state space models using intraday prices are found to reliable in estimating the electricity market structures. |
| Robinson and Baniak (2002) | Illustrate that generators with market power may have incentives to create volatility in the spot market to benefit from higher risk premia in the contract market | Daily average pool prices from 1 April 1990 to 31 May 1996 for the English and Welsh electricity industry | Rank of the change in the logarithm of the spot price | Shifts in pool price volatility at expiry of coal contract and during the period of two year price cap | Non-parametric tests on densities corresponding to the normal; logistic; double exponential; and Cauchy distributions | At the expiry of the coal contract, the generation companies have the opportunity to exert market power to increase the level and volatility of the pool prices. The volatility of the pool price also increased during the two year price cap. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Solibakke (2002) | Model the conditional mean and variance of the spot electricity price as it is the underlying instrument for derivatives in the electricity market. | Daily spot price in the Nordic spot electricity market from October 1992 to January 2000 | Log first difference of the daily spot price | Day-of-week and month-of-year effects in the conditional mean equation; and also in the conditional variance equation | Three Student t GARCH processes are estimated: asymmetric GARCH (AGARCH); truncated GARCH; and exponential GARCH (EGARCH) | The truncated GARCH and asymmetric GARCH (AGARCH) processes out performed the exponential model and these processes were significant in modelling the electricity dynamics. |
| Bystrom (2003) | Alternative estimation of different minimum variance hedge ratio which determines how many futures contracts should be bought or sold for each spot contract to minimise the variance of the return portfolio | Daily spot and future prices from NordPool from 2 January 1996 to 21 October 1999 | Daily spot and futures returns | Lagged spot and futures returns in the conditional mean; and conditional variance equations | A naive or one-to-one hedge ratio where one spot contract is offset by exactly one futures contract; OLS-hedge ratio where the spot returns is regressed on futures returns; bivariate constant conditional correlation GARCH; and Orthogonal GARCH with time varying correlation | The out-of-sample forecasts show that the simple OLS-hedge ratio is more successful in reducing the portfolio variance than the more complex conditional GARCH or Orthogonal GARCH hedge ratios. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Goto and Karolyi (2003) | Examine volatility dynamics across hubs within each market | Daily average prices for the US (8 markets), NordPool (9 markets) and Australia (5 markets) of varying lengths | Returns in the conditional mean equation | Demand; seasonal effects | GARCH(1,1) without jumps and include seasonality; GARCH(1,1) with jumps but no time dependent intensity; and GARCH(1,1) with time-dependent jumps | The ARCH model with time-dependent jumps best explains the price volatility features in all regional markets across three countries. The degree of persistence; implied probabilities; and jump intensities are similar in spite of different factors influencing supply and demand. |
| Huisman and Mahieu (2003) | Model spot electricity price spikes using a regime switching model separate from the mean reversion process | Daily electricity prices for the Dutch APX, German LPX and UK markets with different time spans | Natural log of spot prices for the deterministic equation and the stochastic changes in the spot prices for the stochastic equation | The deterministic equation is explained by dummy variables for Saturday and Sunday. The stochastic equation is a function of mean reversion; volatility; jumps and spikes | Mean reversion; and Markov regime switching models to separate the normal and spike periods | The results show that the mean reversion is stronger after the periods in which the spikes occur than during the normal period. This implies that the spikes are short-lived. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| Hadsell, Marathe and Shawky (2004) | Measure regional similarity and differences in volatility between five US spot electricity markets | Daily spot electricity prices spanning May 1996 to September 2001 for five major American markets, namely: California-Oregon Border (COB); Palo Verde; Cinergy; Entergy; and Pennsylvania-New Jersey-Maryland (PJM) | Log of the difference of the pool prices (returns) in the conditional mean and volatility in the conditional variance | Monthly seasonal effects; and an asymmetric factor to take account of the different effects of positive errors (good news) and negative errors (bad news) on the conditional variance equation | Threshold autoregressive conditional heteroskedastistic (TARCH) model incorporating an asymmetric factor to take account of the different effects of positive errors (good news) and negative errors (bad news) on the conditional variance equation. | There is a steady decline in the ARCH term in all markets with a less consistent increase in the GARCH effect. The asymmetric effect is negative and significant for the entire period in all markets, indicating a strong market response to negative news. There are regional differences in persistence of volatility season patterns across the five markets. |
| Li and Flynn (2004) | Examine patterns in prices of the deregulated electricity markets and show whether these predictable patterns can shape future actions of the consumer | Daily average prices for 13 deregulated markets - Canada, US (3 markets) Germany, Britain, Spain, Scandinavia, Australia (4 markets) and New Zealand | Average power price for each period is normalised against the average weekday price and similarly for weekend prices; ratio maximum to minimum prices for weekday and weekend; and ratio of average weekday to average weekend | NA | Diurnal patterns; filtering; and correlation | Britain and Spain show electricity price patterns that are predictable and consistent, therefore consumers can plan their consumption behaviours. In South Australia the price patterns are irregular and inconsistent, so customers have to manage their risks through hedging mechanisms. |

| Author(s) | Objectives | Sample | Dependent Variable | Independent Variables | Techniques | Main Findings |
|---|---|---|---|---|---|---|
| de Jong (2005) | Capture the spike in the spot electricity markets | Hourly spot prices for six European and two US electricity markets with one market starting from January 2002 and another April 2002 and the remaining six starting from January 2001 with all markets ending in March 2004 | Log spot prices | Deterministic and stochastic components | Five different stochastic components: Mean-reverting; stochastic Poisson jumps; regime switching with stochastic Poisson jumps; regime switching with three regimes and stochastic Poisson jumps; regime switching with independent spikes | Regime switching models out perform GARCH(1,1) or Poisson jump models in capturing the dynamics of electricity prices. |

Notes: ARCH - Autoregressive Conditional Heteroskedasticity, DF - Dickey-Fuller, ADF - Augmented Dickey-Fuller, GARCH - Generalised Autoregressive Conditional Heteroskedasticity, OLS - Ordinary Least Squares.

## 3.4 Multivariate Studies of Spot Electricity Prices

The earlier study by De Vany and Walls (1999a) makes an interesting starting point as this is the only study that examines the inter-relationship between two regional spot electricity markets by questioning whether the highly complex western electricity transmission grid in the US has led to a more integrated electricity industry. This grid interconnects the entire western US, from Canada to Mexico and east as far as Montana, Utah and New Mexico under a structure of decentralisation and deregulation.

De Vany and Walls (1999a) take a multivariate approach to understanding electricity pricing ehaviour between regional power markets in eleven regional markets by examining evidence of integration over the period December 1994 to April 1996. These eleven regional markets are California/Oregon, Four-Corners, Central Rockies, Inland Southwest, Mead, Mid-Columbia, Midway/Sylmar, Northern California, Northwest/Northern Rockies, Palo Verde and Southern California. Using daily spot prices collected from the day ahead over-the-counter market, De Vany and Walls (1999a) employ Augmented Dickey-Fuller (ADF) unit root tests to first detect the presence of non-stationarity in both peak and off-peak series for each market. The presence of unit root or non-stationarity is evident in all series with the exception of off-peak prices in the Northern California market. There is evidence of stationarity in the first differences of the price series.

De Vany and Walls (1999a) also apply cointegration analysis of order one to test for price convergence between each of 55 pairs of markets during peak and off-peak periods. The random walk analysis is used to test for the strength of market integration between two markets; that is, how strongly and also perfectly two markets are integrated. Finally, the existence of unit roots in eigenvalues of vector autoregressive processes is used to examine pricing stability in wholesale electricity markets. The results indicate a high degree of market integration between markets that are not necessarily physically connected: with cointegration being found for peak prices in forty-eight of the fifty-five market pairs (87 percent); and all fifty-five market pairs for off-peak prices. De Vany and Walls (1999a) argue that the lack of cointegration in several markets was evidence of transfer constraints within some parts of the Western Electricity Grid, though on the whole the study findings are suggestive of an efficient and stable wholesale power market. This is a noteworthy study as it is the only empirical analysis that explores the inter-relationship of spot electricity prices among pairs of regional markets applying the Augmented Dickey-Fuller and cointegration techniques. These methodologies are appropriate as the spot price series are non-stationary.

Bystrom (2003) examines the short-term hedging performance of the Nordic spot electricity price with electricity futures using different ways of estimating the minimum variance hedge ratio. The hedge ratio allows the investor to determine how many futures contracts can be bought or sold for each spot contract in order to minimise the variance of the returns of the portfolio. The logarithm of the daily spot and futures price series from 2 January 1996 to 21 October 1999 are stationary at levels. Five different hedge ratios are estimated: the naïve one-to-one hedge ratio where one spot contract is off-set by one futures contract; the time invariant OLS-hedge ratio; the dynamic moving average hedge ratio (50 days back in time); the constant conditional bivariate GARCH model to capture the time varying variance; and the orthogonal GARCH using principal components to generate the number of orthogonal factors. Based on the out-of sample forecasts on their ability to reduce the portfolio variance, the first two simpler hedge models perform better than the more sophisticated models. This study examines the inter-relationship between the spot and futures electricity markets rather than the inter-relationship between two regional markets as explored by De Vany and Walls (1999a).

The papers by De Vany and Walls (1999a) and Bystrom (2003) have inspired the research into inter-relationships between Australian regional electricity markets as highlighted in Chapters 4 and 5. These chapters make further contributions by examining inter-relationships between more than two markets.

## 3.5 Univariate Studies of Spot Electricity Prices

The remainder of this literature review is based on stationary time series and univariate techniques to profile the intra-relationship of spot electricity markets. The main feature is an appraisal of research using a variety of stationarity tests, vector autoregressive (VAR), autoregressive conditional heteroskedasticity (ARCH), generalised ARCH (GARCH) models to explain volatility clustering and persistence in the spot electricity price series. This is followed by a summary of works involving mean-reversion, jump-diffusion and regime-switching models. Such studies investigate the speed of mean-reversion and the price jumps/spikes that result from supply and demand of a commodity with virtually no storage.

### 3.5.1 Vector Autoregressive (VAR), ARCH and GARCH Models

Initially, a group of papers is presented that employ Dickey-Fuller (DF), Augmented Dickey-Fuller and various non-linear models (Helm and Power, 1992; Walls, 1999; DeVany and Walls, 1999b; Robinson, 2000; Wolak, 2000; Guthrie and Videbeck, 2002; Robinson and Baniak, 2002 and Li and Flynn, (2004). This is followed by a collection of well-cited papers involving various ARCH or GARCH processes.

Helm and Power (1992) produce one of the first research papers that attempts to provide an explanation of the pool pricing behaviour. Helm and Power (1992) use Dickey-Fuller (DF) and Augmented Dickey-Fuller (ADF) unit root tests on the daily pool price and demand in the British supply industry from April 1990 to August 1991. They include a dummy variable to take account of the initial expiry date of the first contract for differences on the 22 March 1991. All series are found to be non-stationary and strongly cointegrated. A simple error correction model, with the inclusion of lagged prices, produces a reliable relationship between pool price and demand. The results indicate that, in the long-run, there is a change in the relationship between pool price and demand.

Walls (1999) produce the seminal work on electricity futures markets. The paper examines the effects of *trading volume* and *time to maturity* on spot price volatility for fourteen futures electricity contracts. The data involves daily data on electricity futures contracts traded on the New York Mercantile Exchange (NYMEX) for delivery at California-Oregon-Border (COB) and Palo Verde Nuclear Switchyard (PV) from 29 March 1996 to 26 November 1996. Phillips Perron (PP) unit root tests reject the hypothesis that volatility and log of volume of trade are non-stationary, therefore standard regression techniques can be applied to these series. The results show that volatility and the estimated coefficient of maturity for a majority of the electricity contracts are significant and negative; thus are consistent with the Samuelson hypothesis that price volatility increases as the future contract approaches maturity, even with the inclusion of the log volume of trade.

Walls teamed with DeVany (DeVany and Walls, 1999b) also use the Augmented Dicky-Fuller (ADF) and Choleski variance decomposition to show daily electricity prices converge between interconnected markets; for five decentralised regional markets in western United States spanning December 1994 to April 1996. The results suggest that the decentralised markets and local arbitrage are able to produce a near uniform/stable price over the transmission network, thus indicating that the markets are informationally efficient. The main contribution of this paper is that it is the seminal research implementing stationarity tests and cointegration with applications to a complex deregulated commodity.

Robinson (2000) explores autoregressive models – where the pool price is regressed on lagged pool prices of period one and period six and a non-linear logistic term – to model the behaviour of pool prices in the English and Welsh wholesale electricity markets. Robinson and Baniak (2002) extend the research by introducing non-parametric tests involving distributional densities – such as the normal, logistic double exponential and Cauchy – to forecast pool prices in the English and Welsh electricity markets. Wolak (2000) also employs autoregression with eight lags and eigenvalues of the residual covariance matrix to forecast spot prices in the English, Welsh, Swedish and Norwegian, Victorian and New Zealand markets. Guthrie and Videbeck (2002) introduce high frequency, half-hourly data, in the autoregressive model which also encompassed daily and monthly dummies to assess electricity prices in New Zealand. Li and Flynn (2004) use diurnal patterns to determine if there are differences between average weekday and weekend consumption patterns in 13 deregulated markets involving Canada, US, Germany, Britain, Spain, Scandinavia, Australia and New Zealand. The daily pool prices are normalised against the average weekday price for weekday data; and the average weekend price for weekend data. North American markets exhibit a monotonic weekday peak while all other markets exhibit more than one price peak. Britain and Spain show patterns that are consistent and predictable thus enabling consumers to manage their electricity consumption. By contrast, other markets such as South Australia show patterns that are inconsistent and it is difficult for consumers to predict prices. Consumers in such markets have to manage their risks through hedging mechanisms. The main contribution of these research papers lies in the application of autoregressive time series techniques to model the pricing behaviour of deregulated electricity markets.

The following papers employ a family of autoregressive conditional heteroskedastistic models (ARCH). To begin with, Robinson and Taylor (1998) use daily returns of electricity company share prices from 10 December 1990 to 11 March 1996 to measure volatility changes in twelve UK regional electricity companies (RECs) before and after an unexpected intervention by the electricity regulator, on 7 March 1995. A simple autoregressive conditional heteroskedastistic (ARCH) model includes a dummy variable to reflect the time of the regulator's intervention on 7 March, 1995 (spike) in the mean equation and also a dummy variable to represent the subsequent period from 3 March 1995 (shift in volatility) to the conditional variance equation. In the conditional mean equation, the impulse effect of the regulatory intervention on the 7 March 1995 is negative and significant in all twelve markets. This indicates a large fall in share prices of the RECs on the announcement of the intervention. For the conditional variance equation, the estimated coefficients for the ARCH term demonstrate a significant level of persistence in ten of the RECs. The results indicate a significant estimated coefficient of the dummy variable for eight of the twelve markets. This demonstrates that the conditional variance has found a new level. The main contribution of this study lies in the inclusion of dummy variables to take account of regulatory intervention in the conditional mean and variance equations of the ARCH process. This research is the leading work using the ARCH process to measure volatility in the spot electricity market.

Solibakke (2002) studies the characteristics of the daily price changes of the System Price of the Nordic spot electricity power market, spanning October 1992 to January 2000. This study is motivated by the fact that the electricity price series is the underlying instrument for derivatives in the power industry. This is the first study that analyses the conditional mean and variance equations by taking account of the deviation from the normal distribution in spot price series. Solibakke (2002) initially estimates the conditional mean equation using the log first difference of the daily spot price in the Nordic spot electricity market being adjusted for day-of-week and month-of-year effects. The log of the squared residuals from the conditional mean equation is used to estimate the conditional variance equation, which once again is adjusted for calendar effects. The results of the conditional mean show significant price change patterns over the week with high power usage on Mondays and lower usage on Saturday but with no significant monthly patterns. By contrast, there is evidence of both day-of-week and month-of-year effects in the conditional variance equation. Volatility increases on Mondays and Saturdays; and during May to July.

In addition, Solibakke (2002) employs a family of univariate autoregressive and moving average ARMA-GARCH-in-Mean models to measure the dynamics of the adjusted daily spot price changes and volatility clustering. Three GARCH models are employed: asymmetric GARCH (AGARCH), truncated GARCH (GJR) and exponential GARCH (EGARCH). To take account of the kurtosis and skewness of the spot electricity prices, a maximum likelihood algorithm based on a Student t distributed log-likelihood function with the degrees of freedom to be estimated by the model is incorporated in the GARCH process.

The estimated coefficients of the autoregressive part of the conditional mean equations exhibit dependence on price changes up to 14 lags for all three models. The estimates of the in-mean parameter are insignificant in all three models, suggesting a rejection of the mean-variance total risk model. The conditional variance equation indicates significant ARCH and GARCH effects with the ARCH effect being larger in magnitude. The asymmetric coefficient is insignificant for all three models implying equal reaction patterns to positive and negative shocks in the spot market. The degrees of freedom of the Student t distribution are significant; representing that the spot price series have 'fat-tails'. Using the Schwarz Information Criterion (SIC), Solibakke (2002) finds the truncated (GJR) and asymmetric (AGARCH) processes out-performed the exponential model and these processes are significant in modelling the electricity dynamics. This main contribution of this paper lies in the incorporation of asymmetric and fat-tailed characteristics to assess the spot electricity prices.

Hadsell et al. (2004) model the volatility of the wholesale electricity prices of five major American markets, namely: California-Oregon Border (COB); Palo Verde;

Cinergy; Entergy; and Pennsylvania-New Jersey-Maryland (PJM), covering the period from May 1996 to September 2001. The main motivation of this paper is to estimate the dynamics of the volatility of the deregulated spot price to forecast the future spot prices. A threshold autoregressive conditional heteroskedastistic (TARCH) model which incorporates an asymmetric factor to take account of the different effects of positive errors (good news) and negative errors (bad news) on the conditional variance equation is used to investigate the volatility dynamics of these markets. It is hypothesised that the occurrence of negative return (bad news) will increase volatility more than positive return (good news) of the same magnitude. All five markets are traded on the NYMEX and only differ between markets in the size of contract and the delivery location. The markets were fully deregulated in spring 1998. It was noted that after deregulation the COB and Palo Verde electricity markets were more volatile. Initially, The TARCH model is employed to estimate the conditional variance equations for the daily returns over the entire period for all five American electricity markets, then sub-periods spanning 1996 to 1997, 1998 to 1999 (full deregulation) and 2000 to 2001 (periods of higher volatility in spot prices) and also individual years from 1996 to 2001.

Hasell et al. (2004) discover that the ARCH and GARCH effects are significant for all five markets and for each period. The ARCH effects declined soon after full deregulation thus suggesting that market participants base decisions on the day-before returns rather than long-run expectations which are new and not yet available for the recently deregulated participants. The high value for ARCH effect immediately after deregulation implies unstable volatility characterised by slow price adjustments under the new regime. The majority of models dealing with the asymmetric effect is significant and negative for all markets over the entire period thus implying that ‘good news’ has a positive impact on volatility which is contrary to the expectations for financial markets. For individual years, in the case of COB and PV, the asymmetric effects were not significant before deregulation but significant in years after deregulation. Over the entire period, volatility is quite persistent for COB and PV and less persistent for the other three markets. The persistence estimates in volatility are greater than one for the COB and PV markets suggesting the shocks are permanent. After deregulation the persistence estimates are found to be less than one implying the shocks were mean-reverting.

Hadsell et al. (2004) also incorporate seasonal effects to take account of the monthly variations in the conditional variance equation of the TARCH model. No consistent seasonal patterns are found in the seasonal effects. This paper examines the important differences in the wholesale price volatility of five American electricity markets not only with respect to the ARCH, GARCH and degree of persistence but also asymmetric properties and seasonal effects. The paper uses the TARCH process including asymmetry and month-of-year effects to model the daily spot returns. The paper differs from Solibakke (2002) who adjusted the original price series for seasonality *prior* to the GARCH modelling process.

Goto and Karolyi (2003) employ univariate jump reverting and GARCH processes with and without time dependency to analyse the multiple regional trading areas in the deregulated electricity markets, namely: US, NordPool and Australia. Daily peak spot prices for eight trading areas in the US span from 24 April 1998 to December 2002. The NordPool data cover nine trading areas spanning January 1993 to December 2002. The Australian data for five trading areas is from December 1998 to December 2002. Goto and Karolyi (2003) show that the GARCH models with seasonally time dependent jumps are significant in modelling price volatility in all regional markets for the US, Nordic and Australian electricity markets. This study differs from the previous studies by including a time dependent component in the GARCH process.

The research, using GARCH processes to model the dynamics of univariate electricity price series, inspired the research in Chapter 6, which explores a family of GARCH processes to assess the dynamics of the Australian electricity spot prices. Chapter 6 extends the above studies by taking account not only of the skewed and fat-tailed characteristics; but also the non-linearity of the conditional variance component of the spot price series.

### 3.5.2 Stochastic Models with Mean-Reversion and Jumps and Spikes

Some researchers argue that models for electricity pricing should encompass time-varying volatility and jumps in the electricity prices (Deng, 2000; Knittel and Roberts, 2001 and Escribano et al., 2002). As Goto and Karolyi (2003) point out, when demand for electricity increases, which in turn pushes up prices, there are greater incentives for more expensive generators to enter into the supply side, so some degree of mean-reversion is expected. The following collection of research takes account of jumps, spikes and mean-reversion in the spot electricity markets.

Deng (2000) extends the commonly used Ornstein-Uhlenbeck mean–reversion process, which is borrowed from financial economics to assess the dynamics of spot electricity prices. Deng (2000) observes that the spot prices can be considered as a state variable or as a function of several state variables and can be suitably modelled by jumps and stochastic volatility processes. The change in price is a function of the deviation of the price from equilibrium (which consists of the long-run average price and the rate of mean-reversion) and a random volatility or jump intensity component (involving a standard Wiener process). This basic model is extended to a time-varying model by including systematic variations such as seasonal effects in the mean-reversion component.

Another variation to the mean-reversion process is to allow the jump intensity to vary over time by including time-of-day and seasonal fluctuations. In addition, the regime-switching model is also used to capture the systematic fluctuation between 'abnormal' and 'normal' equilibrium states of supply and demand for this commodity. Several stochastic models of energy commodity price behaviour are specified in the context of a deregulated US electricity industry. Using a number of models and assumptions (including mean-reversion, jump-diffusion and regime-switching), Deng (2000) aims to more accurately reflect the physical characteristics of electricity in commodity spot price behaviour models as a first step in applying a real options approach to valuing physical assets in the electricity industry. Deng (2000) demonstrates that the mean-reversion jump-diffusion models of the energy spot prices can be used to explain the high levels of implied volatility in the market prices of traded electricity options in the US markets.

The study by Lucia and Schwartz (2001) uses the dynamics of spot prices to calculate the valuation of a contract price. This study is important as it aims to predict the systematic behaviour of electricity prices over time by incorporating changes in demand (due to economic activity) and periodic behaviour of consumption (due to climatic conditions as explanatory variables). The spot price model is made up of two components. The first component represents the systematic behaviour as demand and seasonal fluctuations are introduced as explanatory variables to the deterministic function. The second component consists of a diffusion stochastic process, which incorporates the time-varying volatility and jumps in the price series.

Lucia and Schwartz (2001) apply one and two factor mean diffusion stochastic process models in the context of the deregulated Norwegian spot electricity market with an emphasis on the relationship between spot and derivative electricity prices. The one factor model is represented by the deterministic function over time and a diffusion stochastic process. The two factor model extends on the one factor model by adding a short-term mean-reverting component and a long-term equilibrium price. An important implication of adding the second factor is that changes in prices of the future contracts at different maturities are not perfectly correlated. This is in contrast with the one factor model.

Using a sample of daily spot prices from 1 January 1993 to December 1999, Lucia and Schwartz (2001) evaluate the parameters of the deterministic functions then use these parameter estimates to value electricity derivative contracts. The results generally reveal that the seasonal patterns play an important role in evaluating the spot pricing behaviour. There is different volatility between summer and winter seasons. The models also exhibit a significant mean-reverting diffusion process. Their study differs from that of Deng (2000) by including a second factor in the stochastic process.

Knittel and Roberts (2001) use various models to analyse the Northern California electricity market, such as: the mean reversion; time varying mean reversion; jump diffusion; time varying jump diffusion processes; an autoregressive moving average (ARMA) model; and an exponential autoregressive conditional heteroscedastistic (EGARCH) model. A sample of 21,216 half-hourly observations, spanning 1 April 1998 to 30 August 2000, is used to examine the distributional and temporal (peak, off-peak, weekday, weekends and four seasons) patterns of the deregulated electricity prices. A mean-reverting process captures the autocorrelation present in the price series but ignores the temporal patterns. The time-varying mean-reverting model which includes the intraday, weekend or weekday and seasonal effects improves on the previous model but still fails to forecast the erratic nature of the price series. The jump diffusion model which attempts to incorporate the leptokurtic nature of the price series and the jump diffusion time varying model show a significant increase in the probability of a jump but the reliability of these models according to the root mean squared forecast errors is very poor.

The ARMA model improves forecast accuracy due to the inclusion of higher order lags. Finally, the EGARCH process is estimated to take account of how news innovations could have an asymmetric impact on the price volatility. The ARCH and GARCH effects are significant thus indicating a high degree of persistence. The estimated asymmetric effect is significant and positive, thus suggesting the process of an 'inverse leverage effect'. This implies that the positive shocks to spot electricity prices exacerbate the conditional variance more than negative shocks. The novelty of the Knittel and Roberts (2001) study lies in the introduction of a GARCH process to replace the stochastic component in the mean-reversion models.

Escribano et al. (2002) employ a general and flexible model to encompass the main features – such as interaction between jumps, GARCH and mean reversion behaviour of electricity prices – in six deregulated markets, namely: Argentina, Australia (Victoria), New Zealand (Heyward), Scandinavia (NordPool), Spain and the US (Pennsylvania-New Jersey-Maryland; PJM). Daily prices, expressed in local currency, cover different sample periods, which are not stated in the paper. Escribano et al. (2002) employ six models: Model 1, a Gaussian model with constant variance and without jumps; Model 2, a GARCH(1,1)-Gaussian model without jumps; Model 3, a Poisson-Gaussian model without jumps; Model 4, a Poisson-Gaussian model with time-varying intensity for jumps; Model 5, a GARCH(1,1)-Poisson-Gaussian model with constant intensity; and Model 6, a GARCH(1,1)-Poisson-Gaussian model with time-varying intensity for jumps. The sinusoidal functions of the Wiener process are included in the model to capture the deterministic seasonal behaviour of spot electricity prices. The stochastic volatility and mean-reversion are represented in the GARCH process. A Poisson distributed random variable is introduced to take account of jumps with the possibility of time-dependent intensity in the spot prices. Six GARCH(1,1)-Gaussian or Poisson-Gaussian models are investigated.

The results for all six deregulated markets showed that the models with increased complexity produced improved goodness of fit (according to Schwartz Criteria) as compared to the results of the basic GARCH(1,1) model. The results reinforce that the probability of observing jumps is not constant over time. The most complex GARCH model, encompassing time-varying jumps, produces the best results for Australia, New Zealand, NordPool and PJM. There is significant seasonal pattern in jump behaviour, with a higher probability of observing a jump in June, July or August. In addition, various unit root tests incorporating jumps and GARCH errors are used to test the null hypothesis of nonstationarity against the alternative of stationarity or mean-reversion. The optimal models for all markets are found to be mean-reverting. The main innovation of the Escribano et al. study is to estimate a general and flexible model to take account of the interaction between jumps, GARCH and mean reversion behaviour of electricity prices.

Huisman and Mahieu (2003) aim to capture the mean-reverting and the extreme jumps or spikes in spot electricity prices. The spot price at any point in time can be in any one of the three different regimes: a normal regime with a mean-reverting component; an abnormal regime with price jumps or spikes also with a mean-reverting component; and a regime which measures the return to normal regime from the abnormal regime. Huisman and Mahieu (2003) assume that spikes return to the normal regime after one day. A regime switching model is used to identify price spikes separately from the normal regime for the Dutch APX, German LPX and the UK markets. The results show that the mean-reversion is stronger just after the periods in which the spikes occur, than during the normal period. This shows that the spikes are short-lived. This study adds to the previous studies which use stochastic jumps to model spikes in that previous studies do not take account of the fact that the price spikes are short-lived.

Bierbrauer et al. (2003), de Jong and Huisman (2002) and de Jong (2005) extend on the research by Huisman and Mahieu (2003) which makes no allowance for consecutive spikes that may arise. Bierbrauer et al. (2003), de Jong and Huisman (2002) and de Jong (2005) propose a two-regime model which permits a spike regime of log-normal prices with consecutive spikes.

These papers based on stochastic models of the deregulated electricity markets gave impetus to the research in Chapter 7 where the Australian spot electricity prices and volatility are assessed using a regime switching model to take account of the spike/abnormal regime separately from that of the normal regime.

## 3.6 Concluding Remarks

From the literature review, only two out of 21 (10 percent) research papers use multivariate analyses to assess the dynamics of the spot electricity markets, while eight out of 21 (38 percent) of the univariate analyses employ stochastic techniques and the majority of research (52 percent) involve the univariate ARCH and GARCH processes. This thesis is undertaken within a context of little empirical research concerning market pricing within each spot market and the recent integration of separate state-based markets to form a national electricity market in Australia.

Better understanding of the dynamics of electricity pricing is likely to throw light on the efficiency of pricing and the impact of interconnection within the centralised markets which still are primarily composed of commercialised and corporatised public sector entities. A fuller understanding of the pricing relationships between these markets enables the benefits of interconnection to be assessed as a step towards the fuller integration of the regional electricity markets into a national electricity market. This provides policy inputs into both the construction of new interconnectors and the preparation of guidelines for the reform of existing market mechanisms.

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# 4 Transmission of Prices and Price Volatility in Australian Electricity Spot Markets: A Multivariate GARCH Analysis

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## Abstract

This paper examines the transmission of spot electricity prices and price volatility among the five regional electricity markets in the Australian National Electricity Market (NEM): namely, New South Wales, Queensland, South Australia, the Snowy Mountains Hydroelectric Scheme and Victoria. A multivariate generalised autoregressive conditional heteroskedasticity model is used to identify the source and magnitude of price and price volatility spillovers. The results indicate the presence of positive own mean spillovers in only a small number of markets and no mean spillovers between any of the markets. This appears to be directly related to the physical transfer limitations of the present system of regional interconnection. Nevertheless, the large number of significant own-volatility and cross-volatility spillovers in all five markets indicates the presence of strong autoregressive conditional heteroskedasticity and generalised autoregressive conditional heteroskedasticity effects. This indicates that shocks in some markets will affect price volatility in others. Finally, and contrary to evidence from studies in North American electricity markets, the results also indicate that Australian electricity spot prices are stationary.

## 4.1 Introduction

The Australian National Electricity Market (NEM) was established on 13 December 1998. It currently comprises four state-based [New South Wales (NSW), Victoria (VIC), Queensland (QLD) and South Australia (SA)] and one non-state based [Snowy Mountains Hydroelectric Scheme (SNO)] regional markets operating as a nationally interconnected grid. Within this grid, the largest generation capacity is found in NSW, followed by QLD, VIC, the SNO and SA, while electricity demand is highest in NSW, followed by VIC, QLD and SA. The more than 70 registered participants in the NEM, encompassing privately and publicly owned generators, transmission and distribution network providers and traders, currently supply electricity to 7.7 million customers with more than $8 billion of energy traded annually (for details of the NEM's regulatory background, institutions and operations see NEMMCO, 2001 and 2002; ACCC, 2000 and IEA, 2001).

Historically, the very gradual move to an integrated national system was predated by substantial reforms on a state-by-state basis, including the unbundling of generation, transmission and distribution and the commercialisation and privatisation of the new electricity companies, along with the establishment of the wholesale electricity spot markets (Dickson and Warr, 2000). Each state in the NEM initially developed its own generation, transmission and distribution network and linked it to another state's system via interconnector transmission lines. However, each state's network was (and still is) characterised by a very small number of participants and sizeable differences in electricity prices were found. The foremost objective in establishing the NEM was then to provide a nationally integrated and efficient electricity market, with a view to limiting the market power of generators in the separate regional markets (for the analysis of market power in electricity markets see Brennan and Melanie, 1998; Joskow and Kahn, 2002; Wilson, 2002 and Robinson and Baniak, 2002).

However, a defining characteristic of the NEM is the limitations of physical transfer capacity. QLD has two interconnectors that together can import and export to and from NSW, NSW can export to and from the SNO and VIC can import from the SNO and SA and export to the SNO and to SA. There is currently no direct connector between NSW and SA (though one is proposed) and QLD is only directly connected to NSW. As a result, the NEM itself is not yet strongly integrated with interstate trade representing just seven percent of total generation. During periods of peak demand, the interconnectors become congested and the NEM separates into its regions, promoting price differences across markets and exacerbating reliability problems and the market power of regional utilities (IEA, 2001; ACCC, 2000 and NEMMCO, 2002).

While the appropriate regulatory and commercial mechanisms do exist for the creation of an efficient national market, and these are expected to have an impact on the price of electricity in each jurisdiction, it is argued that the complete integration of the separate regional electricity markets has not yet been realised. In particular, the limitations of the interconnectors between the member jurisdictions suggest that, for the most part, the regional spot markets are relatively isolated. Nevertheless, the Victorian electricity crisis of February 2000 is just one of several shocks in the Australian market that suggests spot electricity pricing and volatility in each regional market are still potentially dependent on pricing conditions in other markets. These are, of course, concerns that are likely to be just as important in any other national or sub-national electricity market comprised of interconnected regions.

In the US, for example, De Vany and Walls (1999a) used cointegration analysis to test for price convergence in regional markets in the US Western Electricity Grid. On the whole the findings were suggestive of an efficient and stable wholesale power market, though De Vany and Walls (1999a) argued that the lack of cointegration in some markets provided evidence of the impact of transfer constraints within the grid. Later, De Vany and Walls used vector autoregressive modelling techniques and variance decomposition analysis to examine a smaller set of these regional markets. They concluded "…the efficiency of power pricing on the western transmission grid is testimony to the ability of decentralised markets and local arbitrage to produce a global pattern of nearly uniform prices over a complex and decentralised transmission network spanning vast distances" (De Vany and Walls, 1999b: 139).

Unfortunately, no comparable evidence exists concerning the interconnected regional electricity markets in Australia, or indeed elsewhere outside the US for that matter. This is important for two reasons. First, unlike the US the Australian NEM represents the polar case of a centrally coordinated and regulated national market. It is, therefore, likely to throw light on the efficiency of pricing and the impact of interconnection within centralised markets still primarily composed of commercialised and corporatised public sector entities. Second, a fuller understanding of the pricing relationships between these markets enables the benefits of interconnection to be assessed as a step towards the fuller integration of the regional electricity markets into a NEM. This provides policy inputs into both the construction of new interconnectors and guidelines for the reform of existing market mechanisms.

At the same time, the manner in which volatility shocks in regional electricity markets are transmitted across time arouses interest in modelling the dynamics of the price volatility process. This calls for the application of autoregressive conditional heteroskedasticity (ARCH) and generalised ARCH (GARCH) models that take into account the time-varying variances of time series data (suitable surveys of ARCH modelling may be found in Bollerslev, et al., 1992; Bera and Higgins, 1993 and Pagan, 1996). More recently, the univariate GARCH model has been extended to the multivariate GARCH (MGARCH) case, with the recognition that MGARCH models are potentially useful developments regarding the parameterisation of conditional cross-moments. Although the MGARCH methodology has been used extensively in modelling financial time series (see, for instance, Dunne, 1999; Tai, 2000; Brooks et al., 2002 and Tse and Tsui, 2002), to the authors' knowledge a detailed study of the application of MGARCH to electricity markets has not been undertaken. Since this approach captures the effect on current volatility of both own-innovation and lagged volatility shocks emanating from within a given market and cross-innovation and volatility spillovers from interconnected markets it permits a greater understanding of volatility and volatility persistence in these interconnected markets. It is within the context of this limited empirical work that the present study is undertaken.

Accordingly, the purpose of this paper is to investigate the price and price volatility inter-relationships between the Australian regional electricity markets. If there is a lack of significant inter-relationships between regions then doubt may then be cast on the ability of the NEM to overcome the exercise of regional market power as its primary objective, and on its capacity to foster a nationally integrated and efficient electricity market. The paper itself is divided into four sections. Section 4.2

explains the data employed in the analysis and presents some brief summary statistics. Section 4.3 discusses the methodology employed. The results are dealt with in Section 4.4. The paper ends with some brief concluding remarks in Section 4.5.

## 4.2 Data and Summary Statistics

The data employed in the study are daily spot prices for electricity encompassing the period from the date of commencement of the NEM on 13 December 1998 to 30 June 2001. The sample period is chosen on the basis that it represents a continuous series of data since the establishment of the Australian NEM. All price data are obtained from the National Electricity Market Management Company (NEMMCO) originally on a half-hourly basis representing 48 trading intervals in each 24-hour period. Following Lucia and Schwartz (2001) a series of daily arithmetic means is drawn from the trading interval data. Although such treatment entails the loss of at least some ‘news’ impounded in the more frequent trading interval data, daily averages play an important role in electricity markets, particularly in the case of financial contracts. For example, the electricity strips traded on the Sydney Futures Exchange (SFE) are settled against the arithmetic mean of half-hourly spot prices. Moreover, De Vany and Walls (1999a and 1999b) and Robinson (2000) both employ daily spot prices in their respective analyses of the western US and UK spot electricity markets.

Table 4.1 presents the summary of descriptive statistics of the daily spot prices for the five electricity markets. Samples means, medians, maximums, minimums, standard deviations, skewness, kurtosis and the Jarque-Bera statistic and *p*-value are reported. Between 13 December 1998 and 30 June 2001, the highest spot prices are in QLD and SA averaging $42.71/MWh and $57.92/MWh, respectively. The lowest spot prices are in NSW and the SNO with $33.02/Mwh and $32.56/MWh, respectively. The standard deviations for the spot electricity range from $27.84 (SNO) to $92.15 (SA). Of the five markets, NSW and the SNO are the least volatile, while QLD and SA are the most volatile. The value of the coefficient of variation (standard deviation divided by the mean price) measures the degree of variation in spot price relative to the mean spot price.  Relative to the average spot price, NSW and the SNO are less variable than SA and VIC. A visual perspective on the volatility of spot prices can be gained from the plots of daily spot prices for each series in Figure 4.1.

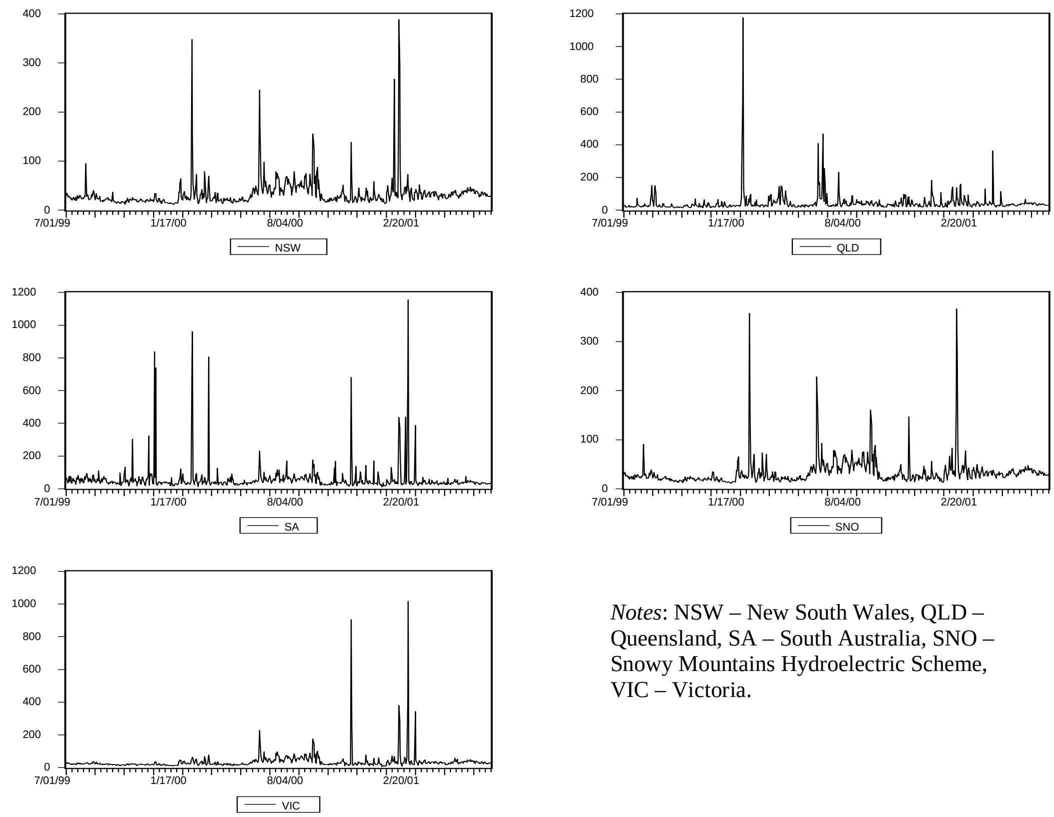
**TABLE 4.1** ***Summary Statistics of Spot Prices in Five Australian Electricity Markets***

| | NSW | QLD | SA | SNO | VIC |
|---|---|---|---|---|---|
| Mean | 33.0244 | 42.7055 | 57.9171 | 32.5624 | 35.5077 |
| Median | 26.4246 | 30.4117 | 38.9352 | 26.5121 | 25.3052 |
| Maximum | 388.2060 | 1175.5260 | 1152.5750 | 366.1698 | 1014.6010 |
| Minimum | 11.6533 | 13.2871 | 11.5225 | 11.0992 | 4.9785 |
| Std. Dev. | 29.6043 | 60.8140 | 92.1549 | 27.8366 | 58.5227 |
| CV | 0.8964 | 1.4240 | 1.5912 | 0.8549 | 1.6482 |
| Skewness | 6.8871 | 11.6290 | 7.6208 | 6.8653 | 12.0381 |
| Kurtosis | 66.2028 | 187.4572 | 69.3994 | 69.0835 | 179.8255 |
| Jarque-Bera | 127447 | 1052805 | 141362 | 138754 | 970003 |
| JB probability | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| ADF test | -5.5564 | -7.6672 | -8.8834 | -6.1225 | -8.2235 |

*Notes*: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria. ADF – Augmented Dickey-Fuller test statistics; CV – coefficient of variation; JB – Jarque-Bera. Hypothesis for ADF test: $H_0$: unit root (non-stationary), $H_1$: no unit root (stationary). The lag orders in the ADF equations are determined by the significance of the coefficient for the lagged terms. Only intercepts are included. Critical values are -3.4420 at 0.01, -2.8659 at 0.05 and -2.5691 at the 0.10 levels.

The distributional properties of the spot price series generally appear non-normal. All of the spot electricity markets are positively skewed and since the kurtosis, or degree of excess, in all of these electricity markets exceeds three, a leptokurtic distribution is indicated. The calculated Jarque-Bera statistic and corresponding *p*-value in Table 4.1 is used to test the null hypotheses that the daily distribution of spot prices is normally distributed. All *p*-values are smaller than the 0.01 level of significance suggesting the null hypothesis can be rejected. These daily spot prices are then not well approximated by the normal distribution. Lastly, each price series is tested for the presence of a unit root using the Augmented Dickey-Fuller (ADF) test. Contrary to previous empirical work De Vany and Walls (1999a and 1999b), which found that spot electricity prices contain a unit root, this study concurs with Lucia and Schwartz (2001) that electricity prices are stationary.

**FIGURE 4.1** ***Daily Spot Electricity Prices for Five Australian Markets, 13/12/1998 – 30/6/2001***




*Notes*: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria.

# 4.3 Methodology

A MGARCH model is developed to examine the joint processes relating the daily spot prices for the five regional electricity markets. The following conditional expected price equation accommodates each market's own prices and the prices of other markets lagged one period.

$$P_t = \alpha + AP_{t-1} + \varepsilon_t \tag{4.1}$$

where $P_t$ is an $n \times 1$ vector of daily prices at time $t$ for each market and $\varepsilon_t | I_{t-1} \sim N(0, H_t)$. The $n \times 1$ vector of random errors, $\varepsilon_t$ is the innovation for each market at time $t$ with its corresponding $n \times n$ conditional variance-covariance matrix, $H_t$. The market information available at time $t$ - 1 is represented by the information set $I_{t-1}$. The $n \times 1$ vector, $\alpha$, represent long-term drift coefficients. The elements $a_{ij}$ of the matrix $A$ are the degree of mean spillover effect across markets, or put differently, the current prices in market $i$ that can be used to predict future prices (one day in advance) in market $j$. The estimates of the elements of the matrix, $A$, can provide measures of the significance of the own and cross mean spillovers. This multivariate structure then enables the measurement of the effects of the innovations in the mean spot prices of one series on its own lagged prices and those of the lagged prices of other markets.

Engle and Kroner (1995) present various MGARCH models with variations to the conditional variance-covariance matrix of equations. For the purposes of the following analysis, the BEKK (Baba, Engle, Kraft and Kroner) model is employed, whereby the variance-covariance matrix of equations depends on the squares and cross products of innovation $\varepsilon_t$ and volatility $H_t$ for each market lagged one period. One important feature of this specification is that it builds in sufficient generality, allowing the conditional variances and covariances of the electricity markets to influence each other, and, at the same time, does not require the estimation of a large number of parameters (Karolyi, 1995). The model also ensures the condition of a positive semi-definite conditional variance-covariance matrix in the optimisation process, and is a necessary condition for the estimated variances to be zero or positive. The BEKK parameterisation for the MGARCH model is written as:

$$H_t = B'B + C'\varepsilon_t \varepsilon_{t-1} C + G' H_{t-1} G \tag{4.2}$$

where $b_{ij}$ are elements of an $n \times n$ symmetric matrix of constants $B$, the elements $c_{ij}$ of the symmetric $n \times n$ matrix $C$ measure the degree of innovation from market $i$ to market $j$, and the elements $g_{ij}$ of the symmetric $n \times n$ matrix $G$ indicate the persistence in conditional volatility between market $i$ and market $j$. This can be expressed for the bivariate case of the BEKK as:

$$\begin{bmatrix} H_{11t} H_{12t} \\ H_{21t} H_{22t} \end{bmatrix} = B'B + \begin{bmatrix} c_{11} c_{12} \\ c_{21} c_{22} \end{bmatrix}' \begin{bmatrix} \varepsilon_{1t-1}^2 & \varepsilon_{1t-1}\varepsilon_{2t-1} \\ \varepsilon_{2t-1}\varepsilon_{1t-1} & \varepsilon_{2t-1}^2 \end{bmatrix} \begin{bmatrix} c_{11} c_{12} \\ c_{21} c_{22} \end{bmatrix} + \begin{bmatrix} g_{11} g_{12} \\ g_{21} g_{22} \end{bmatrix}' \begin{bmatrix} H_{11t-1} H_{12t-1} \\ H_{21t-1} H_{22t-1} \end{bmatrix} \begin{bmatrix} g_{11} g_{12} \\ g_{21} g_{22} \end{bmatrix} \tag{4.3}$$

In this parameterisation, the parameters $b_{ij}$, $c_{ij}$ and $g_{ij}$ cannot be interpreted on an individual basis: "instead, the functions of the parameters which form the intercept terms and the coefficients of the lagged variance, covariance, and error terms that appear are of interest" (Kearney and Patton, 2000: 36). With the assumption that the random errors are normally distributed, the log-likelihood function for the MGARCH model is:

$$L(\theta) = -\frac{Tn}{2} + \ln(2\pi) - \frac{1}{2}\sum_{t=1}^{T}\left(\ln|H_t| + \varepsilon_t^{'}|H_t^{-1}|\varepsilon_t\right) \tag{4.4}$$

where $T$ is the number of observations, $n$ is the number of markets, $\theta$ is the vector of parameters to be estimated, and all other variables are as previously defined. The BHHH (Berndt, Hall, Hall and Hausman) algorithm is used to produce the maximum likelihood parameter estimates and their corresponding asymptotic standard errors. Overall, the proposed model has 25 parameters in the mean equations, excluding the five constant (intercept) parameters, and 25 intercept, 25 white noise and 25 volatility parameters in the estimation of the covariance process, giving 105 parameters in total.

Lastly, the Ljung-Box (LB) $Q$ statistic is used to test for independence of higher relationships as manifested in volatility clustering by the MGARCH model (Huang and Yang, 2000: 329). This statistic is given by:

$$Q = T(T+2)\sum_{j=1}^{p}(T-j)^{-1}r^2(j) \tag{4.5}$$

where $r(j)$ is the sample autocorrelation at lag $j$ calculated from the noise terms and $T$ is the number of observations. $Q$ is asymptotically distributed as $\chi^2$ with $(p - k)$ degrees of freedom and $k$ is the number of explanatory variables. This test statistic is used to test the null hypothesis that the model is independent of the higher order volatility relationships.

## 4.4 Empirical Results

The estimated coefficients and standard errors for the conditional mean price equations are presented in Table 4.2. All estimations are made using the S-PLUS®

statistical software with the GARCH add-on module. For the five electricity spot markets only QLD and SNO exhibit a significant own mean spillover from their own lagged electricity price. In both cases, the mean spillovers are positive. For example, in QLD a $1.00/MWh increase in its own spot price will Granger cause an increase of $0.51/ MWh in its price over the next day. Likewise, a $1.00/MWh increase in the SNO lagged spot price will Granger cause a $0.70/MWh increase the next day. Importantly, there are no significant lagged mean spillovers from any of the spot markets to any of the other markets. This indicates that on average short-run price changes in any of the five Australian spot markets are not associated with price changes in any of the other spot electricity markets, despite the connectivity offered by the NEM.

**TABLE 4.2** ***Estimated Coefficients for Conditional Mean Price Equations***

| | NSW ($i$ = 1) | | QLD ($i$ = 2) | | SA ($i$ = 3) | | SNO ($i$ = 4) | | VIC ($i$ = 5) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Estimated coefficient | Standard error | Estimated coefficient | Standard error | Estimated coefficient | Standard error | Estimated coefficient | Standard error | Estimated coefficient | Standard error |
| CONS. | **12.8966 | 6.8610 | *16.0313 | 11.3500 | 16.18667 | 18.8600 | **12.2740 | 5.5630 | 11.2951 | 20.7400 |
| $a_{i1}$ | 0.0497 | 0.7556 | -0.0135 | 0.0951 | -0.0237 | 0.0844 | 0.5977 | 0.8215 | 0.0248 | 0.1749 |
| $a_{i2}$ | 0.0410 | 2.0470 | ***0.5118 | 0.1291 | -0.0658 | 0.2296 | 0.2046 | 2.2010 | 0.0321 | 0.4654 |
| $a_{i3}$ | -0.1159 | 5.5800 | -0.0529 | 0.3520 | 0.2493 | 0.1946 | 1.0097 | 5.6880 | -0.0344 | 0.6905 |
| $a_{i4}$ | -0.0548 | 0.2984 | -0.0131 | 0.0778 | -0.0265 | 0.0557 | **0.7001 | 0.3884 | 0.0318 | 0.1425 |
| $a_{i5}$ | -0.1641 | 4.0450 | -0.0049 | 0.3352 | 0.0310 | 0.1113 | 0.4664 | 4.0390 | 0.3102 | 0.5095 |

*Notes*: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria. Asterisks indicate significance at * 0.10, ** 0.05, *** 0.01 level

The conditional variance-covariance equations incorporated in the paper's multivariate GARCH methodology effectively capture the volatility and cross-volatility spillovers among the five spot electricity markets. These have not been considered by previous studies. Table 4.3 presents the estimated coefficients for the variance-covariance matrix of equations. These quantify the effects of the lagged own- and cross-innovations and lagged own- and cross-volatility persistence on the own- and cross-volatility of the electricity markets. The coefficients of the variance-covariance equations are generally significant for own- and cross-innovations and significant for own- and cross-volatility spillovers to the individual prices for all electricity markets, indicating the presence of strong ARCH and GARCH effects. In evidence, 68 percent (17 out of 25) of the estimated ARCH coefficients and 84 percent (21 out of 25) of the estimated GARCH coefficients are significant at the 0.10 level or lower.

Own-innovation spillovers in all the electricity markets are large and significant indicating the presence of strong ARCH effects. The own-innovation spillover effects range from 0.0915 in VIC to 0.1046 in SNO. In terms of cross-innovation effects in the electricity markets, past innovations in most markets exert an influence on the remaining electricity markets. For example, in the case of VIC cross-innovation in the NSW, SA and SNO markets are significant, of which NSW has the largest effect. The exception to the presence of strong cross-innovation effects is QLD. No cross-innovations outside of QLD influence that market, and the QLD market does influence any of the other electricity markets, at least over the period in question. This is consistent with the role of QLD in the NEM in that it has only limited direct connectivity with just one other regional market (NSW).

**TABLE 4.3** ***Estimated Coefficients for Variance-Covariance Equations***

| | NSW ($j$ = 1) | | QLD ($j$ = 2) | | SA ($j$ = 3) | | SNO ($j$ = 4) | | VIC ($j$ = 5) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Estimated coefficient | Standard error | Estimated coefficient | Standard error | Estimated coefficient | Standard error | Estimated coefficient | Standard error | Estimated coefficient | Standard error |
| $b_{1j}$ | $^{***}$80.2657 | 16.6300 | 18.7260 | 59.5500 | 120.9672 | 124.3000 | $^{***}$71.3986 | 12.8500 | 75.8586 | 78.8900 |
| $b_{2j}$ | 18.7260 | 59.5500 | $^{***}$336.6956 | 99.0900 | 41.1680 | 332.7000 | 17.1266 | 66.2000 | 31.8362 | 285.4000 |
| $b_{3j}$ | 120.9672 | 124.3000 | 41.1680 | 332.7000 | $^{**}$635.0478 | 353.4000 | $^{*}$120.0339 | 88.1800 | 229.8638 | 219.7000 |
| $b_{4j}$ | $^{***}$71.3986 | 12.8500 | 17.1266 | 66.2000 | $^{*}$120.0339 | 88.1800 | $^{***}$67.6679 | 11.7500 | $^{**}$75.3265 | 41.9500 |
| $b_{5j}$ | 75.8586 | 78.8900 | 31.8362 | 285.4000 | 229.8638 | 219.7000 | $^{**}$75.3265 | 41.9500 | $^{***}$295.1421 | 62.2100 |
| $c_{1j}$ | $^{***}$0.0985 | 0.0140 | 0.0997 | 0.1735 | $^{***}$0.0989 | 0.0278 | $^{***}$0.1013 | 0.0043 | $^{***}$0.0992 | 0.0221 |
| $c_{2j}$ | 0.0997 | 0.1735 | $^{***}$0.1008 | 0.0198 | 0.1232 | 0.2944 | 0.0993 | 0.2777 | 0.0834 | 0.3979 |
| $c_{3j}$ | $^{***}$0.0989 | 0.0278 | 0.1232 | 0.2944 | $^{***}$0.0991 | 0.0216 | $^{***}$0.1021 | 0.0126 | $^{***}$0.0937 | 0.0211 |
| $c_{4j}$ | $^{***}$0.1013 | 0.0043 | 0.0993 | 0.2777 | $^{***}$0.1021 | 0.0126 | $^{***}$0.1046 | 0.0105 | $^{***}$0.0978 | 0.0175 |
| $c_{5j}$ | $^{***}$0.0992 | 0.0221 | 0.0834 | 0.3979 | $^{***}$0.0937 | 0.0211 | $^{***}$0.0978 | 0.0175 | $^{***}$0.0915 | 0.0249 |
| $g_{1j}$ | $^{***}$0.8047 | 0.0133 | $^{***}$0.8412 | 0.3192 | $^{***}$0.7839 | 0.0959 | $^{***}$0.8080 | 0.0001 | $^{***}$0.8034 | 0.0447 |
| $g_{2j}$ | $^{***}$0.8412 | 0.3192 | $^{***}$0.8051 | 0.0416 | 0.6520 | 1.3560 | $^{**}$0.8413 | 0.4615 | 0.8234 | 1.0580 |
| $g_{3j}$ | $^{***}$0.7839 | 0.0959 | 0.6520 | 1.3560 | $^{***}$0.8107 | 0.0309 | $^{***}$0.7868 | 0.0961 | $^{***}$0.8148 | 0.0263 |
| $g_{4j}$ | $^{***}$0.8080 | 0.0001 | $^{**}$0.8413 | 0.4615 | $^{***}$0.7868 | 0.0961 | $^{***}$0.8098 | 0.0128 | $^{***}$0.8056 | 0.0316 |
| $g_{5j}$ | $^{***}$0.8034 | 0.0447 | 0.8234 | 1.0580 | $^{***}$0.8148 | 0.0263 | $^{***}$0.8056 | 0.0316 | $^{***}$0.8119 | 0.0233 |

*Notes*: NSW – New South Wales, QLD – Queensland, SA – South Australia, SNO – Snowy Mountains Hydroelectric Scheme, VIC – Victoria. Asterisks indicate significance at $^{*}$0.10, $^{**}$0.05, $^{***}$0.01 level

In the GARCH set of parameters, 84 percent of the estimated coefficients are significant. For NSW the lagged volatility spillover effects range from 0.7839 for SA to 0.8412 for QLD. This means that the past volatility shocks in QLD have a greater effect on the future NSW volatility over time than the past volatility shocks in other spot markets. Conversely, in QLD the post volatility shocks range from 0.6520 for

SA to 0.8413 for SNO. In terms of cross-volatility for the GARCH parameters, the most influential markets would appear to be NSW and SNO. That is, past volatility shocks in the NSW and SNO electricity spot markets have the greatest effect on the future volatility in the three remaining electricity markets. The sum of the ARCH and GARCH coefficients measures the overall persistence in each market's own and cross conditional volatility. All five electricity markets exhibit strong own-persistence volatility ranging from 0.9032 for NSW to 0.9143 for SNO. Thus, SNO has a lead-persistence volatility spillover effect on the remaining electricity markets. The cross-volatility persistence spillover effects range from 0.7751 for SA 0.9409 for QLD.

Finally, the LB *Q* statistics for the standardised residuals in Table 4.4 reveal that all electricity spot markets are highly significant (all have *p*-values of less than 0.01) with the exception of SNO (a *p*-value of 0.1166). Significance of the LB *Q* statistics for the electricity spot price series indicates linear dependences due to the strong conditional heteroskedasticity. These Ljung-Box statistics suggest a strong linear dependence in four out of the five electricity spot markets estimated by the MGARCH model.

**TABLE 4.4** ***Ljung-Box Tests for Standardised Residuals***

| | NSW | QLD | SA | SNO | VIC |
|---|---|---|---|---|---|
| Statistic | 27.0100 | 32.4600 | 44.7000 | 17.9700 | 50.8700 |
| *p*-value | 0.0077 | 0.0012 | 0.0000 | 0.1166 | 0.0000 |

## 4.5 Conclusions and Policy Implications

This paper highlights the transmission of prices and price volatility among five Australian electricity spot markets during the period 1998 to 2001. All of these spot markets are member jurisdictions of the recently established NEM. At the outset, unit root tests confirm that Australian electricity spot prices are stationary. A MGARCH model is then used to identify the source and magnitude of spillovers. The estimated coefficients from the conditional mean price equations indicate that despite the presence of a national market for electricity, the regional electricity spot markets are not integrated. In fact, only two of the five markets exhibit a significant own mean spillover. This also would suggest, for the most part, that Australian spot electricity prices could not be usefully forecast using lagged price information from either each market itself or from other markets in the national market. However, own-volatility and cross-volatility spillovers are significant for nearly all markets, indicating the presence of strong ARCH and GARCH effects. Conventionally, this is used to indicate that markets are not efficient. Strong own- and cross-persistent volatility are also evident in all Australian electricity markets. This indicates that while the limited nature of the interconnectors between the separate regional markets prevents full integration, shocks or innovations in particular markets still exert an influence on price volatility. Thus, during periods of abnormally high demand for example, the NEM may be at least partially offsetting the ability of regional participants to exert market power.

Nonetheless, the results mainly indicate the inability of the existing network of interconnectors to create a substantially integrated NEM and that, for the most part, the sizeable differences in spot prices between most of the regions will remain, at least in the short-term. This provides validation for new regional interconnectors currently under construction and those that are proposed, and the anticipated inclusion of Tasmania as a sixth region in the NEM. As a general rule, the less direct the interconnection between regions, the less significant the cross-innovation and volatility spillover effects between these regions. This suggests that main determinant of the interaction between regional electricity markets is geographical proximity and the number and size of interconnectors. Accordingly, it may be unreasonable to expect that prices in electricity markets that are geographically isolated market will ever become fully integrated with ‘g-core’ or geographically proximate markets.

The results also indicate that volatility innovations or shocks in all markets persist over time and that in all markets this persistence is more marked for own-innovations or shocks than cross-innovations or shocks. This persistence captures the propensity of price changes of like magnitude to cluster in time and explains, at least in part, the non-normality and non-stability of Australian electricity spot prices. Together, these indicate that neither the NEM nor the regional markets are efficiently pricing electricity and that changes to the market mechanism may be necessary. It may also reinforce calls for the privatisation of some electricity market participants to improve competition, given that the overwhelming majority of these remain under public sector control.

Of course, the full nature of the price and volatility inter-relationships between these separate markets could be either under or overstated by misspecification in the data, all of which suggest future avenues for research. One possibility is that by averaging the half-hourly prices throughout the day, the speed at which innovations in one market influence another could be understated. For instance, with the data as specified the most rapid innovation allowed in this study is a day, whereas in reality innovations in some markets may affect others within just a few hours. Similarly, there has been no attempt to separate the differing conditions expected between peak and off-peak prices. For example, De Vany and Walls (1999a and 1999b) found that there were essentially no price differentials between trading points in off-peak periods because they were less constrained by limitations in the transmission system. Another possibility is that the occurrence of time-dependent conditional heteroskedasticity could be due to an increased volume of trading and/or variability of prices following the arrival of new information into the market. It is well known that financial markets, for instance, can still be efficient but exhibit GARCH effects in price changes if information arrives at uneven intervals. One future application of modelling would then include, say, demand volume as a measure of the amount of information that flows into the electricity market. This would provide definitive proof of whether the GARCH effects are really evidence of market inefficiency, or the result of the irregular flow of market information.

Research into Australian electricity markets could be extended in a number of other ways. One useful extension would be to examine each of the five electricity markets individually and in more detail. For example, while the sample for this study is determined by the period of tenure of the NEM wholesale electricity spot markets in the separate regions predate this by several years. An examination of the connection between the long-standing electricity spot markets in NSW and VIC would be particularly useful. Another suggestion concerns the electricity strip contracts offered by the SFE (2002) on several of Australia's NEM jurisdictions. An examination of the relationships between Australian spot and derivative electricity prices would then be interesting.

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# 5 Transmission of Prices and Volatility in the Australian Electricity Spot Markets

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# 6 Systematic Features of High-Frequency Volatility in Australian Electricity Markets: Intraday Patterns, Information Arrival and Calendar Effects

# 7 Stochastic Price Modelling of High Volatility, Mean-Reverting, Spike-Prone Commodities: The Australian Wholesale Electricity Market

*This chapter has been submitted as: "Higgs, H. and Worthington, A.C. (under editorial review) Stochastic price modelling of high volatility, mean-reverting, spike-prone commodities: The Australian wholesale electricity market, Resource and Energy Economics".*


## Abstract

It is commonly known that wholesale spot electricity markets exhibit high price volatility, strong mean-reversion and frequent extreme price spikes. This paper employs a basic stochastic model, a mean-reverting model and a regime-switching model to capture these features in the Australian national electricity market (NEM), comprising the interconnected markets of New South Wales, Queensland, South Australia and Victoria. Daily spot prices from 1 January 1999 to 31 December 2004 are employed. The results show that the regime-switching model outperforms the basic stochastic and mean-reverting models. Electricity prices are also found to exhibit stronger mean-reversion after a price spike than in the normal period, and price volatility is more than fourteen times higher in spike periods than in normal periods. The probability of a spike on any given day ranges between 5.16 percent in New South Wales to 9.44 percent in Victoria.


## 7.1 Introduction

The restructuring and deregulation of electricity markets in Australia has brought about fundamental changes in the behaviour of wholesale spot prices. As in like economies, these prices are invariably characterised by high volatility (the variance of prices is very large), strong mean-reversion (prices tend to fluctuate around a long-term equilibrium), and abrupt and unanticipated upward price jumps or spikes which quickly decay (associated with shocks to price-inelastic demand and supply) [electricity prices technically 'spike' rather than 'jump', since they do not move to a new level and remain there, instead quickly revert to the earlier level (Blanco and Soronow, 2001)]. In turn, these reflect the inherent characteristics of competitive electricity markets: seasonality, low marginal production costs, the impact of system breakdowns or outages, constraints on interconnection between markets, limited storability, and even market manipulation [for interesting perspectives on market power in electricity markets (see Brennan and Melanie, 1998; Joskow and Kahn, 2002; Wilson, 2002 and Robinson and Baniak, 2002)]. As a result, major participants in these markets, including generators, retailers and large industrial users, are exposed to significant market risks and are obliged to undertake costly risk management measures.

In point of fact, the Australian electricity market is regarded as significantly more volatile and spike-prone than many comparable systems. To start with, it is well known that electricity is among the most volatile of commodities. A report by the US Federal Energy Regulatory Commission (2004) comparing the annualised historical volatility of the electricity market (Cinergy hub), with natural gas prices (Henry hub), oil (NYMEX) and the stock market (S&P 500) found electricity volatilities approaching 300 percent of its average price, never more than 100 percent in other energy commodities, and 20 percent or lower in equity markets. In Australia, and using similar techniques, Booth (2004) calculated historical volatilities in the Australian market in excess of 900 percent. At least part of this volatility is a direct result of price spikes, with 20-30 percent of average annual pool prices in the Australian National Electricity Market (NEM) coming from price spikes occurring for less than one percent of hours in a year (Booth, 2004).

Observing fewer spikes in the US (Pennsylvania-New Jersey-Maryland pool), Bushnell (2003) explained it as a consequence of US regulators being more willing to modify the behaviour of suppliers, while Australia, "…which also uses a uniform price auction, places fewer restrictions on suppliers, and [as a consequence] price spikes, are a standard feature" (Mount et al., 2006: 63). Moreover, half-hourly spot prices in Australia can and do approach the price cap of $10,000/megawatt-hour

(MWh), as compared to a cap of US$1,000/MWh in the US, a feature Booth (2004: 1) links with generators exploiting "…the freedom afforded them under the National Electricity Code to arrange their price bids, and/or withhold capacity in various ways, causing a small number of very large price spikes, and increasing the annual average pool prices to more acceptable levels".

Clearly, knowledge of the dynamics of spot prices, particularly the spike process, is of importance for real and financial asset valuation and risk management for electricity generators, retailers and end-users. For example, modelling price spikes accurately is important for generation assets, particularly peaking plants, whose value is entirely dependent on the existence of price spikes that facilitate the recovery of high marginal costs and the recouping of fixed costs over very short running periods (Blanco and Soronow, 2001). Large industrial users are also concerned with the better modelling of prices because of cost efficiencies associated with load shedding during peak periods, while retailers can benefit from improved forecasting of volatility and price spikes to hedge against upside price risk. A White Paper issued by the Australian Government (2004) highlights the economic impact of price spikes: "These peaks in demand, while generally being of short duration, can impose high costs on the supply system…peaks lasting for only 3.2 percent of the annual duration of the market accounted for 36 percent of total spot market costs". More realistic appraisals of the volatility of spot prices can also be used to determine the financial value of electricity derivatives. For instance, even with deep out-of-the-money options, it is still necessary to model price spikes directly in order to price and hedge effectively (Blanco and Soronow, 2001).

Accordingly, the purpose of this paper is to model Australian spot electricity prices with allowances for high volatility, strong mean-reversion and frequent price spikes. While a nascent literature is already concerned with Australian electricity prices (see, for example, Higgs and Worthington, 2003; Worthington and Higgs, 2004; Higgs and Worthington, 2005 and Worthington et al., 2005) none has yet fully addressed these stylised features of contemporary electricity markets. In this regard, past studies in the US and elsewhere have attempted to capture some characteristics of electricity spot prices with mean-reverting specifications (see, for instance, Lucia and Schwartz, 2002). Unfortunately, while these models are useful for modelling storable commodities, such as oil and gas (Schwartz, 1997 and Pindyck, 1999), they are less useful for electricity, where there is little opportunity for direct or indirect storage to smooth price spikes (except in the presence of substantial hydropower capacity) (de Jong, 2005).

A common solution is to add a stochastic jump process to the mean-reverting specification to allow for spikes (see, for example, Deng, 2000 and Knittel and Roberts, 2001). The mean-reversion component in these models is used to force electricity prices back to the normal level after a jump or spike has occurred: that is, mean-reversion is directly associated with the jump process (Huisman and Mahieu, 2003). However, mean-reverting stochastic jump processes are limited in two respects. First, while these models are well suited to foreign exchange and equity markets where jumps are ordinarily sustained and revert slowly to some long-run equilibrium, the spikes in electricity markets are typically short-lived and die out in a matter of days or even hours. This can only be achieved with an unrealistically high mean reversion parameter (de Jong, 2005). Second, the jump process is assumed to be constant over time, whereas in electricity markets we typically observe alternating periods of high and low jump frequency. If the mean-reversion exists only in the 'normal' price process, Huisman and Mahieu (2003: 426) argue that a "…stochastic jump process with mean-recession [may] lead to an erroneous specification of the true mean-reversion process".

In response, Deng (2000), Huisman and de Jong (2003), Bierbrauer et al. (2003), Huisman and Mahieu (2003) and de Jong (2005) specify regime-switching models to disentangle the mean-reversions from the spikes. Deng (2000) and Huisman and Mahieu (2003), for example, propose a three regime-switching model to accommodate a first (or normal) regime with moderate mean-reversion and volatility, a second (or spike) regime when prices suddenly increase, and a third (or jump-reversal) regime when prices are forced back to the normal regime. The main benefit of this model is that the prominent features of electricity spot prices, mean-reversion and spikes are included, with the spikes treated as truly independent disruptions from the (normally) stable price process. One limitation, however, is that there is no allowance for the multiple consecutive spikes that are sometimes observed in electricity markets.

The remainder of the paper is structured as follows. Section 7.2 explains the data employed in the analysis and presents some brief descriptive statistics. Section 7.3 discusses the methodology employed. The results are dealt with in Section 7.4. The paper ends with some concluding remarks in Section 7.5.

## 7.2 Data and Descriptive Statistics

The data employed in the study are daily spot prices of the Australian National Electricity Market (NEM) comprising the (partially) interconnected regional markets of New South Wales (NSW), Queensland (QLD), South Australia (SA) and Victoria (VIC) (for details of the NEM's regulatory background, institutions and operations see NEMMCO, 2001; ACCC, 2000; IEA, 2001 and NEMMCO, 2005). The sample period is from 1 January 1999 to 31 December 2004. All price data is obtained from the National Electricity Market Management Company (NEMMCO) originally on a half-hourly basis representing 48 trading intervals in each 24-hour period. A series of daily arithmetic means is drawn from the trading interval data, yielding 2,192 observations for each market. While Deng (2000), Lucia and Schwartz (2002), Knittel and Roberts (2001) and Huisman and Mahieu (2003) also employ daily prices in their respective analyses of the western US and UK spot electricity markets, this specification invariably involves some loss of information on price spikes. For example, price-spikes are sometimes most pronounced in peak hourly prices, but are usually averaged away in weekly and monthly data. Daily observations are a good compromise given the unwieldiness of intraday data.

Table 7.1 presents summary of descriptive statistics of the daily spot prices for the four markets. Samples means, minimums, maximums, standard deviations, coefficients of variation, skewness, kurtosis and the Jarque-Bera and Augmented Dicky-Fuller statistics and their *p*-values are reported. Between 1 January 1999 and 31 December 2004, the highest spot prices are in QLD and SA averaging \$38.66/MWh and \$42.71/MWh, respectively. The lowest mean spot prices are in NSW (\$33.82/MWh) and VIC (\$32.74/MWh). The standard deviations range between \$47.23 in VIC to \$66.08 in QLD. Of the four markets NSW and VIC are the least volatile, while QLD and SA are more volatile. The coefficient of variation measures the degree of variation relative to the mean. On this basis, SA and VIC are less variable than either NSW or QLD. A visual perspective on the volatility of the spot prices can be gained from the plots of each series on the left-hand side of Figure 7.1. These plots clearly indicate the strong mean-reversion and infrequent and the price spikes so characteristic of electricity spot prices.

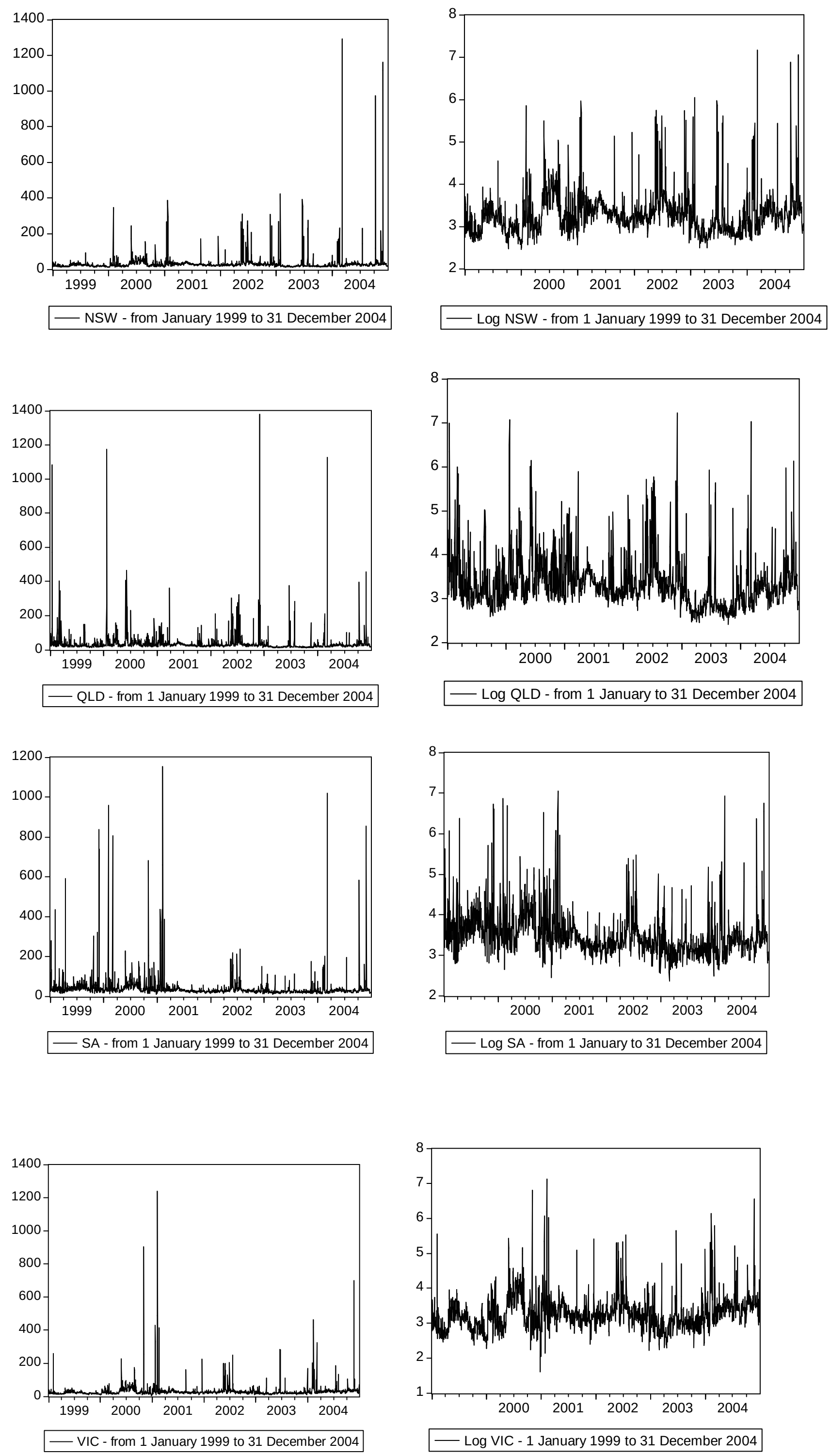
**TABLE 7.1** ***Selected Descriptive Statistics of Daily Spot Prices ($/MWh) and Natural Logarithms of Spot Prices, 1 January 1999 –31 December 2004***

| | New South Wales (NSW) | | Queensland (QLD) | | South Australia (SA) | | Victoria (VIC) | |
|---|---|---|---|---|---|---|---|---|
| Statistic | Price | lnPrice | Price | lnPrice | Price | lnPrice | Price | lnPrice |
| Mean | 33.822 | 3.301 | 38.660 | 3.371 | 42.707 | 3.515 | 32.743 | 3.290 |
| Minimum | 11.653 | 2.456 | 11.171 | 2.413 | 10.607 | 2.362 | 4.979 | 1.605 |
| Maximum | 1293.003 | 7.165 | 1379.269 | 7.229 | 1152.575 | 7.050 | 1239.197 | 7.122 |
| Standard deviation | 57.275 | 0.497 | 66.077 | 0.583 | 67.630 | 0.529 | 47.234 | 0.499 |
| Coefficient of variation | 1.693 | 0.150 | 1.709 | 0.173 | 1.584 | 0.151 | 1.443 | 0.152 |
| Skewness | 14.560 | 2.482 | 11.801 | 2.058 | 10.066 | 2.228 | 14.136 | 1.916 |
| Kurtosis | 271.672 | 13.846 | 190.617 | 9.504 | 123.466 | 11.738 | 282.539 | 11.145 |
| J-B statistic | 6.67E+06 | 1.30E+04 | 3.27E+06 | 5.41E+03 | 1.36E+06 | 8.79E+03 | 7.21E+06 | 7.40E+03 |
| J-B *p*-value | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| ADF *t*-statistic | -33.350 | – | -24.814 | – | -33.347 | – | -31.034 | – |
| ADF *p*-value | 0.000 | – | 0.000 | – | 0.000 | – | 0.000 | – |

Notes: ADF – Augmented Dickey-Fuller; coefficient of variation is standard deviation divided by mean; J-B – Jarque-Bera. Hypothesis for ADF test: $H_0$: unit root (non-stationary), $H_1$: no unit root (stationary).

All of the spot electricity markets are significantly positively skewed, and since the kurtosis, or degree of excess, in all of these electricity markets exceeds three, leptokurtic distributions are indicated. The fat-tailed distributions are also very characteristic of electricity spot prices, while positive skewness indicates that the upward jumps are more intense than the jump reversals (Huisman and Mahieu, 2003). The null hypothesis of distributional normality is rejected at the 0.01 level for all series using the Jarque-Bera statistic. Finally, each price series is tested for the presence of a unit root using the Augmented Dickey-Fuller (ADF) test. Contrary to some earlier empirical work (see, for example, De Vany and Walls, 1999a and 1999b in the US context) which found that spot electricity prices contain a unit root, this study concurs with Worthington et al. (2005) that spot electricity prices, at least in Australia, are stationary. Table 7.1 presents the same statistics for the natural logarithms of the prices, with the series plotted on the right-hand side of Figure 7.1.

**FIGURE 7.1** ***Daily Spot Prices ($/MWh) and Natural Logarithms of Spot Prices, 1 January 1999 – 31 December 2004***



## 7.3 Model Specification

The dynamics of Australian electricity spot price comprise of two components. The first is the totally predictable component and is represented by a known deterministic function $f(t)$. The second is a stochastic component and is represented by $X(t)$. Let $P(t)$ be the natural logarithm of the daily spot price at time $t$ and is the sum of the two components given by:

$$P(t) = f(t) + X(t) \qquad \text{where } t = 1, 2, ..., T \tag{7.1}$$

### 7.3.1 The Deterministic Component

The deterministic component aims to capture any predictable variation in electricity price behaviour arising from regularities over time. The simplest deterministic function is a constant function of time, $t$, which reflects a constant mean-reverting process for the daily spot price (or the natural logarithm of the daily spot price). This implies that a linear trend for a log spot price variable is an exponential trend for the spot price itself. A time trend was initially included in the deterministic function, but while the estimated coefficient was significant it was very small in magnitude and was excluded from the final analysis.

It is more likely that important spot price variation is reflected in day-of-week and month-of-year effects. In this paper, it is hypothesised that spot electricity prices are higher during weekdays and during warmer and colder months. Solibakke (2002), for example, found that price volatility in the Nordic spot electricity market increased strongly on Mondays and Saturdays, especially during May, June and July. Herbert (2002: 34) also presented evidence that "…there is seasonality in (electricity) price risk. Not surprisingly, price risk increases in the summer…power prices also increase in the winter". Finally, Higgs and Worthington (2005) also concluded that Mondays and peak winter and summer months were associated with higher spot electricity prices.

Seasonal behaviour can be incorporated in these models as either dummy variables (Lucia and Schwartz, 2002 and Huisman and Mahieu, 2003) or sinusoidal cosine functions (Lucia and Schwartz, 2002). However, dummy variables are generally preferred as they are intuitive and relatively easy to interpret (Lucia and Schwartz, 2002). Three sets of dummy variables are included. The first captures the variation in spot prices between working and non-working days, while a second reflects seasonal fluctuations throughout the year. A final dummy variable is included to incorporate the inception of two new interconnectors between the mainland regional markets: the QLD and NSW Interconnector (QNI) began operation on 18 February 2001 while the Murraylink interconnector between SA and VIC commenced on 2 September 2002 (a third interconnector, the Basslink between Tasmania (not included) and VIC, was completed in 2006). The inclusion of interconnection dummy variables draws upon evidence by Worthington et al. (2005) that the presence and size of regional interconnectors plays an important role in Australian electricity price dynamics.

The deterministic component $f(t)$ is then specified as:

$$f(t) = \mu_0 + \beta_1 D_t + \sum_{2}^{12} \beta_i M_{it} + \gamma_1 INT \tag{7.2}$$

where $D_t$ are dummy variables for the day-of-the-week having values of one when $t$ is a holiday or weekend and zero otherwise (weekdays are the reference category), $M_i$ are eleven dummy variables for each month with a value of one for $M_2$ (February) and zero otherwise, having a value of one for $M_3$ (March) and zero otherwise, and so on (January is the reference category), $INT$ is an interconnector dummy variable having a value of one after 18 February 2001 for QLD and NSW and after 2 September for SA and VIC and zero otherwise, and $\beta_i$ for $i$ = 1, 2,…, 12 and $\gamma_1$ are parameter coefficients. Parameter $\mu_0$ represents the mean spot price.

### 7.3.2 The Stochastic Component

The change in the stochastic component of the spot price is defined as:

$$dX(t) = dP(t) - df(t) \qquad \text{where } t = 1, 2, ..., T \tag{7.3}$$

The operator $d$ measures the change in the value of the variable that is $dX(t) = X(t)-X(t-1)$. In the current analysis, three alternatives are used to measure the dynamics of the stochastic component of electricity spot prices: (i) a basic stochastic model; (ii) a mean-reverting model; and (iii) a Markov regime-switching model. To start with, the basic stochastic model is a simplistic approach where it assumed that the stochastic change in the spot price is normally distributed, such that:

$$dX(t) = \sigma_0 \xi(t) \qquad \text{where } \xi(t) \sim \text{N}(0,1) \tag{7.4}$$

In this model, the volatility of changes in the spot electricity price is measured by the parameter $\sigma_0$.

The mean-reverting model reflects findings by Pilipovic (1998), Clewlow and Strickland (2000), Lucia and Schwartz (2002) and Huisman and Mahieu (2003), amongst others, that spot electricity prices tend to fluctuate around some long-term equilibrium price level, $\mu_0$ in equation (7.2), which reflects the marginal cost of producing electricity. The rate of mean-reversion is introduced as prices are forced back to their long-run equilibrium after the actual price has deviated from this equilibrium; negatively if the spot price is higher than the mean-reversion level and positively if lower. The mean-reverting model is defined as:

$$dX(t) = -\alpha_0 X(t-1) + \sigma_0 \xi(t) \qquad \text{where } \xi(t) \sim \text{N}(0,1) \tag{7.5}$$

where $\alpha_0$ is the rate of mean-reversion and all other variables are as previously defined.

Finally, the unique behaviour of spot electricity prices can be thought of as being divided into separate regimes with different underlying processes where a spike can be considered as a change or temporal level shift to an abnormally high price. This potentially arises from a number of factors, including generator breakdowns or abnormally high or low temperatures. In these instances, the price will return to the equilibrium level very quickly when the generator is repaired or supply is obtained from another generator or temperatures return to more normal levels. Since the sudden up-jump in spot prices is followed rapidly by a down-jump, it assumes that mean-reversion forces high prices back to the long-run equilibrium price.

This paper follows Huisman and Mahieu (2003) who propose a Markov regime-switching model to separate mean reversion in the normal (non-spike) and spike price periods. The regime framework assumes that on any day the electricity spot price lies in one of three regimes: (i) a normal (regime 0) when prices follow 'normal' electricity price dynamics; (ii) an initial jump regime (regime +1) when prices suddenly increase (decrease) during a price spike; and (iii) a downturn regime (regime -1) when electricity prices revert to normal after a spike has occurred. The deseasonalised stochastic component, $dX(t)$, of the regime-switching model used to capture the three regimes is specified as:

$$dX(t) = -\alpha_0 X(t-1) + \sigma_0 \xi(t) \quad \text{in regime } 0 \quad \text{where } \xi(t) \sim \mathrm{N}(0,1) \tag{7.6}$$

$$dX(t) = \mu_1 + \sigma_1 \xi(t) \quad \text{in regime } +1 \quad \text{where } \xi(t) \sim \mathrm{N}(0,1) \tag{7.7}$$

$$dX(t) = -\alpha_{-1} X(t-1) + \sigma_{-1} \xi(t) \quad \text{in regime } -1 \quad \text{where } \xi(t) \sim \mathrm{N}(0,1) \tag{7.8}$$

The mechanism that allows the price level to move from one regime to another is achieved through a Markov transition matrix which contains the probabilities of jumping from one regime on a given day to another regime on the next day. Maximum likelihood estimates are used to determine the parameters and regimes given the conditions for each regime.

The switches between the regimes are assumed to have one-period transmission probabilities. Let $\pi$(i,j) be the probability that the electricity price process switches from regime j in period $t$ to regime i in period $t$ + 1. Let $\pi$(0,0) represent the probability that no spike will occur and $\pi$(+1,0) = 1 - $\pi$(0,0) be the probability of a spike. As there cannot be a process of switching from the normal regime to the spike reverting regime, then $\pi$(-1,0) is set to zero. Being in the spike regime +1 at day $t$, the model assumes that spikes are only short-lived, say, today, and the reverting regime begins tomorrow. This is represented by $\pi$(-1,+1) equals one and $\pi$(0,+1) and $\pi$(+1,+1) are zero. Being in a mean reverting regime -1 at day $t$, the price process is expected to be back in the normal regime the next day, thus $\pi$(0,-1) equals one and $\pi$(+1,-1) and $\pi$(-1,-1) are equal zero. Given these combinations of the different regimes, only the Markov probability $\pi$(0,0) is estimated. To keep the Markov probability estimates between 0 and 1, the Markov probability is calculated as:

$$\pi(0,0) = \frac{\exp(p)}{1 - \exp(p)} \tag{7.9}$$

where $p$ is the parameter to be estimated, exp is the exponential and all other variables are as previously defined.

## 7.4 Empirical Results

The estimated coefficients and standard errors for the three different models (basic stochastic, mean-reverting and regime-shifting) in this study are presented in Table 7.2. All models share a deterministic component and this is included in the uppermost panel of Table 7.2. The stochastic component is represented in turn by a basic stochastic function (next-to-uppermost panel), mean-reverting function (next-to-lowermost panel) and regime-shifting function (lowermost panel).

To start with, the estimated coefficients, standard errors and *p*-values of the deterministic function *f*(t) are presented in the uppermost panel in Table 7.2. The average log price level ($\mu_0$) is 3.3319 for NSW, 3.3536 for VIC, 3.7156 for SA and 3.7615 for QLD. This indicates that average equilibrium prices range from $27.99/MWh (NSW) [i.e. $27.99 = exp(3.3319)] to $43.01/MWh (QLD). The weekend and public holidays' effect ($\beta_1$) is significant and negative in all four markets indicating that Saturday, Sunday and public holiday electricity prices are lower than weekday prices. In dollar terms, prices on weekends and public holidays are generally lower by $0.73-$0.74/MWh in QLD, SA and VIC and $0.85/MWh in NSW. Most monthly effects are also significant. Generally (and relative to January), prices are higher in most regional markets (except QLD) in February and the peak winter months of May-August and lower in September-December. The highest (lowest) monthly prices by state are June (March) in NSW, January (April) in QLD, February (March) in SA and June (April) in VIC. The interconnector dummy variable (INT) is also significant for all markets excluding VIC. The respective negative and positive INT coefficients for QLD (-0.2313) and NSW (0.0544) suggest that after the introduction of the QNI interconnector, spot prices in QLD have fallen ($0.79/MWh), while those in NSW have increased ($1.06/MWh). The introduction of the Murraylink interconnector appears to have reduced prices only in SA (-0.3336) by ($0.72/MWh) with no significant change in VIC.

The next-to-uppermost panel in Table 7.2 presents the estimated coefficients and standard errors of the basic stochastic model. The estimated volatility of the daily changes in the spot price is significant in all four markets, with daily volatilities ranging from 0.0140 for VIC to 0.0179 for QLD. As indicated, daily prices are most volatile in QLD (0.0179) and NSW (0.0171) and least volatile in SA (0.0161) and

VIC (0.0140). The next-to-lowermost panel of Table 7.2 contains the parameter estimates of the mean-reverting model. This extends the basic stochastic model by including mean-reversion in the dynamic price process. The mean-reversion parameter $\alpha_0$ is significant and positive for all spot markets and ranges from 0.3213 for VIC to 0.4115 for SA. Electricity prices exhibiting strong mean-reversion suggests that the spot price returns rapidly from some extreme position, such as a price spike, to equilibrium. That is, price spikes are short-lived. In terms of a comparison with international spot prices, the strength of mean-reversion (short-lividness of spikes) in Australian electricity markets is less than the Dutch APX market (0.473) but higher than either the German LPX (0.284) or the UK Telerate (0.206) markets (Huisman and Mahieu, 2003).

**TABLE 7.2** ***Estimation Results for Basic Stochastic, Mean-reverting and Regime-Switching Models***

| | | New South Wales (NSW) | | Queensland (QLD) | | South Australia (SA) | | Victoria (VIC) | |
|---|---|---|---|---|---|---|---|---|---|
| | | Coefficient | Std. error | Coefficient | Std. error | Coefficient | Std. error | Coefficient | Std. error |
| Deterministic component | $\mu_0$ | 3.3319*** | 0.0369 | 3.7615*** | 0.0431 | 3.7156*** | 0.0368 | 3.3536*** | 0.0355 |
| | Eq.Pr | 27.9902 | | 43.0137 | | 41.0829 | | 28.6063 | |
| | $\beta_1$ | -0.1494*** | 0.0217 | -0.2599*** | 0.0254 | -0.2694*** | 0.0222 | -0.2634*** | 0.0215 |
| | $\beta_2$ | 0.0082 | 0.0500 | -0.1380** | 0.0584 | 0.1200** | 0.0510 | 0.1162** | 0.0493 |
| | $\beta_3$ | -0.2037*** | 0.0490 | -0.0741 | 0.0572 | -0.1110** | 0.0498 | -0.1127** | 0.0482 |
| | $\beta_4$ | -0.1889*** | 0.0494 | -0.2971*** | 0.0577 | -0.0918* | 0.0502 | -0.1744*** | 0.0486 |
| | $\beta_5$ | 0.1358*** | 0.0490 | -0.1282** | 0.0572 | 0.1004** | 0.0498 | 0.1805*** | 0.0482 |
| | $\beta_6$ | 0.2635*** | 0.0494 | -0.0130 | 0.0577 | 0.1128** | 0.0502 | 0.2623*** | 0.0486 |
| | $\beta_7$ | 0.1712*** | 0.0490 | -0.0812 | 0.0572 | 0.1049** | 0.0498 | 0.1797*** | 0.0482 |
| | $\beta_8$ | 0.0413 | 0.0490 | -0.2021*** | 0.0572 | -0.0063 | 0.0498 | 0.1044** | 0.0482 |
| | $\beta_9$ | -0.1294*** | 0.0494 | -0.3713*** | 0.0577 | -0.1065** | 0.0504 | -0.0948* | 0.0487 |
| | $\beta_{10}$ | -0.1018** | 0.0490 | -0.1973*** | 0.0572 | 0.0211 | 0.0499 | -0.0657 | 0.0483 |
| | $\beta_{11}$ | -0.1092** | 0.0494 | -0.2666*** | 0.0577 | 0.0791 | 0.0504 | -0.0449 | 0.0487 |
| | $\beta_{12}$ | -0.1166** | 0.0490 | -0.1608*** | 0.0572 | -0.0537 | 0.0499 | -0.1237** | 0.0483 |
| | $\gamma_1$ | 0.0544** | 0.0211 | -0.2313*** | 0.0247 | -0.3336*** | 0.0213 | -0.0008 | 0.0206 |
| Basic stochastic component | $\sigma_0$ | 0.0171*** | 0.0021 | 0.0179*** | 0.0038 | 0.0161*** | 0.0028 | 0.0140*** | 0.0022 |
| | LnL | -1102.0470 | | -1435.7030 | | -1396.1200 | | -939.6626 | |
| Mean-reverting stochastic component | $\alpha_0$ | 0.3622*** | 0.0165 | 0.3466*** | 0.0162 | 0.4115*** | 0.0173 | 0.3213*** | 0.0157 |
| | $\sigma_0$ | 0.0127*** | 0.0046 | 0.0136*** | 0.0039 | 0.0156*** | 0.0055 | 0.0102*** | 0.0026 |
| | LnL | -883.1969 | | -1227.3200 | | -1140.6150 | | -748.4933 | |
| Regime-switching stochastic component | $\alpha_0$ | 0.3747*** | 0.0166 | 0.2802*** | 0.0233 | 0.3841*** | 0.0174 | 0.3854*** | 0.0166 |
| | $\sigma_0$ | 0.0023** | 0.0011 | 0.0046*** | 0.0008 | 0.0046*** | 0.0011 | 0.0008*** | 0.0002 |
| | $\mu_1$ | 0.9169*** | 0.0285 | 0.5799*** | 0.0687 | 0.8273*** | 0.0247 | 0.5878*** | 0.0226 |
| | $\sigma_1$ | 0.0605* | 0.0319 | 0.0981*** | 0.0319 | 0.0638*** | 0.0235 | 0.0574*** | 0.0213 |
| | $\alpha_{-1}$ | 0.4803*** | 0.0276 | 0.2961** | 0.1241 | 0.5146*** | 0.0268 | 0.4514*** | 0.0332 |
| | $\sigma_{-1}$ | 0.0058* | 0.0032 | 0.0400*** | 0.0131 | 0.0278** | 0.0129 | 0.0201** | 0.0082 |
| | p | 2.9118*** | 0.1792 | 2.4505*** | 0.4951 | 2.4379*** | 0.3763 | 2.3147*** | 0.5444 |
| | $\pi$ | 0.9484 | | 0.9206 | | 0.9197 | | 0.9056 | |
| | LnL | -209.9161 | | -913.8360 | | -410.8549 | | -290.9938 | |

Notes: Asterisks indicate significance at the *** 0.01, ** 0.05 and * 0.10 level. LnL – Log-likelihood. EqPr – equilibrium price.

The estimated volatility coefficient of price changes is again significant for all markets. The daily prices are more volatile in SA (0.0156) and QLD (0.0136) and least volatile in NSW (0.0127) and VIC (0.0102). However, the volatility estimates are lower than in the basic stochastic model, and this suggests that at least some of the volatility in prices (about 25 percent) is linked with the strong mean reversion. Put differently, if spikes (read mean-reversion) are excluded from prices, daily volatility is lower. Moreover, the volatility ranking of the markets has changed, with SA, for instance, moving from the second least volatile to most volatile. This suggests that SA has a higher level of normal-period volatility, whereas volatility in NSW, QLD and VIC owes much to the presence of volatility in spike-periods. The log likelihoods for the mean-reversing models are lower than the basic stochastic model for all series, indicating a better fit.

Finally, the lowermost panel of Table 7.2 presents the estimated parameters of the Markov regime-switching model. The probability of a spike is low for all markets with the parameter $\pi(0,0)$, being the probability of the process in the normal regime today will again be in the normal process tomorrow are 0.9056 (VIC), 0.9197 (SA), 0.9206 (QLD) and 0.9484 (NSW). The probability of a spike therefore varies from 9.44 percent (VIC), 8.03 percent (SA), 7.94 percent (QLD) and 5.16 percent (NSW). In the normal regime (regime 0) the mean-reversion parameter $\alpha_0$ is significant and positive for all Australian electricity markets and ranges from 0.2802 (QLD) to 0.3854 (VIC). Once again, this reveals the importance of mean-reversion in electricity price dynamics and the quicker the return of prices from some extreme position to equilibrium. The estimates of mean reversion in the normal regime are also substantially smaller in magnitude than the mean-reverting models, suggesting that failure to account for price spikes as independent departures from the normal price process significantly overestimates the strength and speed of return to equilibrium prices. The estimated volatility coefficients of price changes ($\sigma_0$) in the normal regime range from 0.0008 (VIC) to 0.0046 for both QLD and SA. This indicates that volatility in electricity markets, once price spikes are excluded, is actually quite low.

In the spike regime (regime 1), the size of a price jump ($\mu_1$) is significant for all markets being the lowest for QLD (0.5799) and VIC (0.5878) and the highest for SA (0.8273) and NSW (0.9169). That is, the average magnitude of price spikes is greatest in SA and NSW. However, the standard error of the size of the spikes in the spike regime is greater in QLD (0.0687) than in any of the other markets. This suggests that the size of price spikes in QLD is more uncertain. The mean-reversion coefficients in the spike regime are much higher than those in the normal regime indicating the more rapid the return of the spike price to equilibrium. Price spikes are clearly short-lived. The estimated volatility of price changes ($\sigma_1$) is significant for all markets and ranges from 0.0574 for VIC to 0.0981 for QLD. These volatilities as expected are somewhat magnified as compared to the estimated volatility estimates in the normal regime. The volatilities in the spike regime as compared to that in the normal regime are respectively 0.0605 and 0.0023 for NSW, 0.0981 and 0.0046 for QLD, 0.0638 and 0.0046 for SA and 0.0574 and 0.0008 for VIC. Broadly speaking, daily volatilities exceed seven percent in spike periods, but are less than half of one percent in normal periods.

In the back-to-normal regime (regime -1), the mean-reversion coefficients are significant for all markets ranging from 0.2961 (QLD) to 0.5146 (SA) and are stronger than the mean-revision coefficients in the normal regime. While all prices return to the equilibrium position more rapidly after a spike than in the normal regime in all markets, the adjustment to equilibrium is quickest and the spikes generally most short-lived in SA.  Finally, since the log-likelihood is lower again, the mean-reverting model with regime jumps has the highest explanatory power for all four spot markets as compared to either basic stochastic or mean-reverting models.

## 7.5 Concluding Remarks

This study uses basic stochastic, mean-reverting and Markov regime-switching models to examine the price dynamics in the Australian wholesale electricity spot markets. While all of these models are useful in modelling spot prices, only the regime-shifting model fully accounts for the high volatility, mean-reversion and spike-prone behaviour so characteristic of electricity markets. A number of salient features are found in this model and these are useful for understanding the price dynamics in the Australian market.

First, the probability of a price spike on any particular day ranges between five percent in NSW to nearly ten percent in VIC. However, while these spikes are frequent, they are short-lived. In fact, prices generally revert faster when returning from spike periods than in normal periods. Second, price spikes account for much of the volatility in electricity spot prices. Daily volatility in normal periods is actually quite low, and appears to cluster closely around the marginal cost of production. Third, there is great variation in the magnitude of spikes in the Australian market, with spikes being generally largest in SA and smallest in QLD. However, price spikes are less uniform in the QLD market, suggesting a higher degree of uncertainty.

Finally, apart from stochastic variation, there is a great deal of deterministic disparity among the various regional markets, in which equilibrium prices, seasonal and day-of-the-week effects and the impact of regional interconnectors diverge. All other things being equal, equilibrium prices are highest in QLD and SA, the differential between weekday and weekend prices is lowest in NSW, and prices are lowest in autumn in NSW, SA and VIC, highest in winter in NSW and VIC, highest in summer in QLD and SA and lowest in spring in QLD. The presence of new interconnectors appears to have most benefited QLD and SA with lower prices, but prices have risen in NSW and are unchanged in VIC.

The main limitation of this study is the rather restrictive assumption regarding spike behaviour and this suggests possible research extensions. First, the methodology employed follows the three regime structure proposed by Huisman and Mahieu (2003): that is, a normal regime, a jump regime created by the spike and a jump reversal regime where the price returns to the normal level. Accordingly, there is no allowance for consecutive spikes that may arise. One solution is a two-regime model following Huisman and de Jong (2003), Bierbrauer et al. (2003) and de Jong (2005) which permits a spike regime of log-normal prices with consecutive spikes.

Second, through the use of daily data, this methodology also sets the shortest duration of a spike to one day. In many instances, short-duration spikes may also occur in half-hourly prices, but these are often averaged away in daily prices. This is especially important because the spiking behaviour in electricity markets appears to exhibit strong time variation, with spikes being relatively more common in peak daylight times. Specification of intraday data would provide a logical resolution to these as yet unexplored features.

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# 8 Evaluating the Informational Efficiency of Australian Electricity Spot Markets: Multiple Variance Ratio Tests of Random Walks

# 9 Conclusion

## 9.1 Summary

This thesis comprises a series of publications, the main findings of which appear within each submitted or published paper. This final chapter includes an overall summary of the main findings and contribution of these papers, their policy implications and limitations. Some suggestions for future research are also made. The first publication presented in Chapter 4 attempted to answer the question whether lagged prices and volatility information flows of the interconnected regional markets could be used to improve forecasts of pricing behaviour in the Australian spot electricity markets, namely, New South Wales, South Australia, the Snowy Mountain Hydroelectric Scheme, Queensland and Victoria. A multivariate generalised autoregressive conditional heteroskedasticity (MGARCH) model was used to identify the source and magnitude of mean, innovation and volatility spillovers between these five markets. Evidence based on the MGARCH model suggests very little integration between the five regional markets, despite the presence of the National Electricity Market (NEM), with only two of the five markets exhibiting significant own mean spillovers.

This suggests that spot electricity prices in Australia cannot be reliably forecasted using lagged price information from either the regional market itself or from other markets in the NEM, and that spot electricity prices do not follow a random walk; that is, they are not conventionally efficient. The results also show the presence of strong ARCH and GARCH effects for all regional markets and that the volatility shocks are persistent over time. This persistence suggests that high (low) volatility of price changes is followed by high (low) volatility price changes; that is, like magnitudes of price changes cluster over time. This price clustering captures the non-normality and non-stability of Australian electricity spot prices.

While the limited nature of the interconnectors between the separate regional markets prevents full integration, shocks or innovations in particular markets are still found to exert an influence on price volatility. During periods of abnormally high demand, for example, the NEM may be at least partially offsetting the ability of regional participants to exert market power. The presence of market power indicates that neither the NEM nor the regional markets are efficiently pricing electricity and that some changes to the market mechanism may be necessary. It also reinforces calls for the privatisation of some electricity market participants to improve competition, given that the overwhelming majority of these remain under public sector control.

The paper presented in Chapter 5 extends this analysis by separating the daily data into peak and off-peak spot electricity prices and the multivariate generalised autoregressive conditional heteroskedastistic (MGARCH) model is once again used to examine the transmission of prices and price volatility among the five Australian regions. Similar conclusions are reached in this chapter, with the finding that most of the electricity markets are not fully integrated and exhibit strong persistence in price volatility.

The paper included in Chapter 6 departs from the subject and modelling of the earlier work in that it examines the price and volatility relationships *within* spot electricity market rather than *between* regional spot electricity markets. This analysis questions whether the inclusion of news arrival, as proxied by the contemporaneous volume of demand, time-of-day, day-of-week and month-of-year effects, can be used as exogenous explanatory variables in explaining intraday price volatility process in spot electricity markets. Four Australian spot markets - New South Wales, Queensland, South Australia and Victoria - and five different univariate Autoregressive Conditional Heteroskedastic (ARCH) volatility processes consisting of the Generalised ARCH (GARCH), RiskMetrics, normal Asymmetric Power ARCH (APARCH), Student and skewed Student APARCH models are estimated using half-hourly prices.

The results indicate that the skewed Student APARCH process outperforms the other four ARCH processes in modelling the intraday price relative volatility in these markets. Based on the results of the skewed Student APARCH process, there is strong evidence of autocorrelation within each market and similarly strong evidence of ARCH and GARCH effects in almost all markets. However, contrary to stock markets, the asymmetric responses are detected which show that volatility rises in response to ‘good news or positive spikes’ and falls in response to ‘bad news or negative spikes’. One of the main innovations of this model is that it accommodates both the right-skewed, fat-tailed properties of the observed data and the role of high-frequency market information and seasonality in price and volatility determination. Accordingly, news arrival such as readily-available market information and defined calendar effects can be useful in forecasting electricity price volatility. This paper (Chapter 6) was the first to use these innovative techniques to model spot electricity prices in Australia.

The paper in Chapter 7 employs a basic stochastic model, a mean-reverting model and a Markov regime-switching model to capture the stylised features of electricity markets. The features so characteristic of deregulated electricity markets – high price volatility, strong mean-reversion and frequent and extreme price spikes – are used to explore the question of whether inherent and uncertain characteristics such as price spikes can be quantified. The results indicate that daily spot price volatility can be best captured by a Markov regime-switching model which includes in the stochastic component three regimes – a normal regime, an initial jump or spike regime and a downturn regime. The results show that for all markets the spot prices exhibit stronger mean-reversion following a price spike than in the normal period, indicating that the mean-reversion found in models without allowance for a jump regime may be overestimated. While price spikes account for much of the volatility in the spot prices, they are short-lived as they return faster to the equilibrium price in the spike period than in the normal period. Accordingly, in contrast to simple models formulated without a spike regime, daily volatility in normal periods is actually quite low, and appears to cluster closely around the long-run marginal cost of production.

The paper in Chapter 8 attempts to answer the final research question to be tested here, whether interstate/regional trade has enhanced the informational efficiency of each spot electricity market, or alternatively, if each spot electricity market follows a random walk. Multiple variance ratio (MVR) tests with both homoskedastic and heteroskedastic variances are used to test for random walks in both peak and off-peak periods. The MVR tests produce two test statistics. One for the null hypothesis of homoskedastic increments random walk and another for the null hypothesis of a heteroskedastic increments random walk. The rejection of the random walk under homoskedasticity could result from heteroskedasticity and/or autocorrelation in the spot electricity price series. The rejection of the heteroskedastic random walk suggests there is evidence of autocorrelation in the spot electricity price series.

For peak and off-peak periods, MVR tests show that all four regional markets, with the exception of the Victorian market in the off-peak period, are informationally inefficient and it cannot be assumed that they follow a random walk. Autoregressive modelling techniques are also found to be useful in assessing Australian spot electricity prices, especially in New South Wales, Queensland, and South Australia during the peak and off-peak period but for Victoria in the peak period only. Despite the presence of a national market for electricity, only the Victorian off-peak period market follows a random walk or is informationally efficient. As is conventional in the literature of liberalised markets, the results of this paper are interpreted as being indicative of market power as opposed to competition. This paper used pioneering techniques never previously employed in evaluating informational efficiency in the Australian electricity market.

## 9.2 Contribution

The main contribution of this thesis lies in the application of state-of-the-art time series techniques to model the behaviour of Australian spot electricity prices. MGARCH and a family of univariate GARCH models are employed to assess price, volatility and market relationships. In addition, the MVR tests are used to determine if each spot electricity market follows a random walk or is informationally efficient.

In Chapters 4 and 5, the MGARCH model is used to examine the inter-relationship across five regional spot markets. These papers are based on the studies by De Vany and Walls (1999) and Bystrom (2003) which use cointegration and bivariate GARCH models to examine the inter-relationship between two regional spot electricity markets. These chapters make further contributions by examining inter-relationships across more than two markets.

In terms of univariate GARCH processes, the important contribution in Chapter 6 lies in the application of Student APARCH and skewed Student APARCH models to explore the intra-relationship of each regional electricity market. Chapter 6 extends on most existing research that uses the GARCH process by taking account not only of the skewed and fat-tailed characteristics; but also the non-linearity of the conditional variance component of the spot price series.

In Chapter 8, the MVR tests are used to determine if Australian spot electricity markets follow a random walk; that is, if they are informationally efficient. The MVR tests extend on the standard unit root tests such as Augmented Dickey-Fuller (ADF), Phillips-Perron (PP) and Kwiatkowski-Phillips-Schmidt-Shin (KPSS). These MVR tests with the null hypothesis of homoskedastic increments random walk together with the null hypothesis of a heteroskedastic increments random walk, present a more stringent alternative.

## 9.3 Policy Implications

This thesis evaluates spot pricing behaviour in electricity markets using state-of-the-art modelling techniques to examine price and volatility relationships between and within Australian regional markets. The study of behaviour of the spot price has economic importance. First, the spot price strongly influences the wholesale contract price which, in turn, dictates the long-run retail price for consumers. Second, the spot price is a large component of cost for direct purchasers such as industrial and commercial consumers (Robinson, 2000 and Robinson and Baniak, 2002). The models presented in this thesis can be used to assess price and price risks in the supply industry and can assist producers, distributors and consumers to manage their risks. Using information obtained from modelling pricing of the electricity industry, the optimal price for electricity can be set to mimic the market price in a competitive industry with a number of non-colluding businesses and minimum barriers to entry. This price has several desirable properties. First, it gives businesses the signals and timing of new investment opportunities. As businesses cannot influence the market price, they have an incentive to produce output at minimum cost and can only earn high profits by cost reducing innovations not available to competitors (Wolak, 2000). The deregulation of the spot electricity markets has given rise to new sets of policy challenges in the supply industry with the aims to achieving economically efficient prices. Deregulation has lead to the ability of firms to cause a significant increase in the market price and to profit from this price increase by price spikes or exercising market power. There are differences in observed market structures in the regional markets. These differences in market structures have led to the implementation of markets rules that allow firms to exercise market power.

## 9.4 Limitations

There are three main limitations in the empirical research undertaken in this thesis. First, the averaging of the half-hourly data to a daily frequency in some of the papers necessarily results in a loss of information. Indeed, the question arises whether daily prices are relevant given that most half-hourly contracts to supply and demand are at prices that may be, but are not necessarily, significantly higher or lower than the average half-hourly price. Through averaging there may be smoothing of some defining features in electricity prices series, especially price spikes which tend to be extremely short-lived. For example, the effects of price spikes in a shorter time frame can reach the Value of Lost Load (VOLL) set at a maximum of $10,000/MWh and can return to normal within a few hours. Nonetheless, it is equally common that the analysis of financial time series is also usually undertaken at a daily frequency or longer, and it is only recently that techniques have been developed to take advantage of intra-day and tick-by-tick data.

Second, two of the papers presented examine the volatility interactions between regional electricity markets with no allowance for systematic influences on electricity price volatility. A natural extension is to include news information such as contemporaneous demand and seasonal effects in these models. The MGARCH model employed in these papers assumes that the innovation or random error term is normally distributed. It would be more appropriate to introduce a skewed Student MGARCH process to take account of the highly skewed and non-normally distributed features of spot electricity prices. The number of parameters estimated in a multiple modelling context can increase dramatically. It would be advisable to explore two or three interconnected regions at a time.

Third, the main limitation discussed in the paper in Chapter 7 is that reliance is placed on a three regime structure includes a normal regime, a jump regime created by the spike and a jump reversal regime where the price returns to the normal level after the spike has occurred. In this model no allowances are made to accommodate consecutive spikes. Another direction is to examine different regime structures such as a two regime-switching model following Bierbrauer et al. (2003), Huisman and de Jong (2003) and de Jong (2005) which permits a spike regime of log-normal prices with consecutive spikes. The results of the three regime-switching model could be compared with the two regime-switching model in order to better explain the stylised features of spike behaviour in the electricity markets.

## 9.5 Suggestions for Future Research

The limitations of this study indicate a number of areas where future research could be usefully applied. First, the frequency of data has a bearing on the estimation of the price and volatility relationships in the Australian electricity markets. In this regard, the price and volatility relationships between and among the regional markets could be under or overstated through misspecification in the data. Future research should take account of high frequency data by employing the half-hourly rather than daily data, with the objective of improving the robustness of the MGARCH, regime-switching and market efficiency models.

Second, the current analysis shows that nearly all spot markets are not informationally efficient. As additional data come to hand, further privatisation of the electricity industry may be advocated in order to enhance efficiency. These efficiency gains would ultimately benefit consumers resulting in lower prices and higher quality output. As the market mechanism continues to change where states further embrace privatisation to promote competition, a natural extension over time is to include ownership or market structure of each regional market to investigate spot price trends.

Third, another extension would be to compare price and volatility relationship between electricity markets in the NEM and Australian electricity jurisdictions outside the NEM such as Western Australia (WA) and Northern Territory (NT). Even though these jurisdictions are not linked by interconnectors with the NEM, mainly because of geographic and physical constraints, they too have embraced competition in their electricity supply industries. The application of univariate

GARCH or Markov regime-switching models would be useful to compare how deregulation has improved efficiency of energy businesses in all Australian regional markets.

Finally, another extension would be to examine the conditions whereby generators are argued to exercise market power through increasing prices by withholding capacity at times of high demand. Market power may be used to explain at least some of the large increases in the wholesale prices of electricity at some times. Empirical evidence to support a presumption of high prices relating the withholding of supplies from the market by suppliers can be based on the competitive benchmark analysis similar to that of Joskow and Kahn (2002) for the Californian spot electricity market. The competitive price benchmark is the short-run marginal cost of supplying electricity from the last unit that clears the market in each hour. Comparing the realised price with the marginal supply cost is a widely acceptable method of measuring the presence of market power. This is useful for examining prices in commodity markets with homogenous products such as spot electricity markets. Some departures from ideal competitive conditions do not necessarily imply that there is market power that is of policy concern. Many markets that are not subject to price controls are imperfectly competitive. Any empirical analysis of pricing behaviour is subject to some degree of uncertainty. The price may depart from the observed marginal cost even in a perfectly competitive market to reflect real capacity constraints and opportunity costs associated with inter-temporal production limits on generators. However, this approach quantifies the extent to which realised market prices can depart from the competitive benchmark prices and provides a useful metric, along with the analysis of withholding behaviour that policy makers can use to judge whether the gap between the competitive benchmark prices and the actual prices is so large that regulatory intervention is justified (Joskow and Kahn, 2002).

## 9.6 References

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