March 2008

The Wholesale Electricity Market in Australia

A report to the Australian Energy Market Commission

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Glossary

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Markets Commission
AER	Australian Energy Regulator
APRA	Australian Prudential Regulation Authority
ASX	Australian Stock Exchange
CCGT	Combined Cycle Gas Turbine
CRA	Charles River Associates
COAG	Council of Australian Governments
DC	Direct Current
DLF	Distribution Loss Factor
DNSP	Distribution Network Service Provider
ERIG	Energy Reform Implementation Group
ERAA	Energy Retailers Association of Australia
ESAA	Energy Supply Association of Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission of South Australia
ETEF	Electricity Tariff Equalisation Fund (New South Wales)
FRC	Full Retail Competition
GW	Gigawatt
IPART	Independent Pricing and Regulatory Tribunal (New South Wales)
LEP	Long-Term Energy Procurement
MCE	Ministerial Council of Energy
MNSP	Market Network Service Provider
MRET	Mandatory Renewable Energy Target

NCC	National Competition Council
NCP	National Competition Policy
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules (‘the Rules’)
NGF	National Generators Forum
MW	Megawatt
OCGT	Open Cycle Gas Turbine
OTC	Over-the-Counter
PC	Productivity Commission
QCA	Queensland Competition Authority
QNI	Queensland to New South Wales Interconnector
RLMS	Resource and Land Management Services
SFE	Sydney Futures Exchange
TLF	Transmission Loss Factor
TNSP	Transmission Network Service Provider
TWh	Terawatt-hours
VENCorp	Victorian Energy Networks Corporation

1. Introduction

In June 2007 NERA Economic Consulting was engaged by the Australian Energy Market Commission (AEMC) to provide advice on the issues that it should consider when assessing the influence of the wholesale gas and electricity markets on competition within the retail gas and electricity markets. The advice provided by NERA took the form of two separate reports, entitled "The Gas Supply Chain in Eastern Australia" and "The Wholesale Electricity Market". Since the completion of these reports in June 2007 a number of events have occurred that have resulted in changes to both the structure of the gas and electricity markets in eastern Australia and the demand and supply conditions prevailing within these markets. A number of proposals have also been made over the last nine months that could significantly alter the competitive landscape prevailing within these markets going forward. It is with this in mind that the AEMC has requested that NERA update the original reports to ensure that they reflect the changes that have occurred over the last nine months.

The most notable change that has occurred within the wholesale electricity market is the decision to expand the Mandatory Renewable Energy Target (MRET) scheme. Following the federal election in 2007, the new Commonwealth government has committed to a goal of supplying 20 per cent of electricity from renewable sources by 2020.

Other significant changes that have occurred across the wholesale electricity market include:

§ Generation - there have been a number of changes in this segment including the commissioning of the Braemar gas fired plant and the 750MW Kogan creek coal fired plant. Additionally the ownership structure of a number of generators and generating companies has changed;

§ Rule changes – on 30 August 2007 the AEMC published the final National Electricity Amendment (Abolition of Snowy Region) Rule determination which will result in the abolition of the Snowy region of the NEM by 1 July 2008;

§ Privatisation – the New South Wales government announced plans to sell their retail businesses and lease out (through long term leases) their electricity generation businesses; and

§ Retail – for the first time in the history of the NEM a Retailer of Last Resort was called due to the collapse of Energy One. This occurred on the back of extremely high prices in the spot market. At the same time the trend towards vertical integration of retail and generation businesses has continued with Origin Energy and TRUenergy committing to new generation projects.

The remainder of this report has been updated to reflect these and other changes that have occurred in the market and is structured as follows:

§ Section 2 provides an overview of the NEM, its participants and electricity consumption;

§ Section 3 discusses the structure of the NEM, focusing on generation capacity, location, ownership, and electricity supply; transmission and distribution; and interconnection between each NEM region;

- Section 4 outlines the retail segment of the market, including the structure of electricity retailers in each of the NEM regions;
- Section 5 discusses the extent of vertical integration between retailers and generators that has occurred in recent years;
- Section 6 discusses the operation of the market including price formulation, dispatch procedures, settlement and treatment of electricity losses;
- Section 7 discusses the approaches to risk management, including the types of risks that arise, and the tools for managing those risks;
- Section 8 provides a brief summary of recent reviews of the wholesale electricity market; and
- Section 9 considers issues arising from the structure and operation of the wholesale electricity market for retail competition.

2. Overview of the National Electricity Market

In the 1990's Australia's electricity market underwent a period of structural reform that led to the establishment of a common wholesale market for the supply of electricity to retailers and end users. This market, the NEM, was eventually established in 1998, linking Victoria, New South Wales, Queensland, the Australian Capital Territory and South Australia and in 2005 was expanded to include Tasmania. The NEM is the world's largest interconnected system stretching for more than 4000 kilometres from Port Douglas in the north of Queensland, to Port Lincoln in South Australia and via the Basslink undersea cable between Victoria and Tasmania. The physical infrastructure encompasses high powered transmission lines known as interconnectors, which carry electricity between regions (depicted in Figure 2.1), and transmission and distribution networks within each region.

The NEM was originally designed to include five distinct regions, represented by Victoria, South Australia, Queensland, New South Wales (including the Australian Capital Territory) and the Snowy Mountains Hydro-Electricity Scheme. Each region operates as a separate market for the supply and demand of electricity although every region is connected through at least one interconnector that allows for electricity to be imported or exported between regions. In 2005 the number of regions increased to six with the entry of Tasmania into the NEM. In accordance with the AEMC's final Rule Determination released on 30 August 2007 the Snowy Region will be abolished from 1 July 2008. This abolishment will result in the Tumut generator becoming part of the New South Wales region and the Murray generator becoming part of the Victoria region.[1]

The NEM operates in accordance with the National Electricity Rules ('the Rules') which govern all aspects of the operation of the market. These include the dispatch rules, provision of obligations on market participants and service providers, the responsibilities of the system operator, the National Electricity Market Management Company (NEMMCO), rules governing the operation of the spot market, prudential requirements and the procedures for dealing with network losses and constraints.

As the independent system operator, NEMMCO has responsibility for the implementation and continued operation of the wholesale market, and a mandate to continually improve its functions whilst maintaining system security. It functions as a non-profit body corporate whose members are the state governments of the NEM.

The AEMC is responsible for the Rules and considers rule change proposals as well as conducting any reviews as directed by the Ministerial Council on Energy (MCE). In assessing rule change applications, the AEMC is required to be satisfied that the NEM Objective will, or is likely to be promoted. Under section 7 of the National Electricity Law, the NEM Objective is:

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-
>
> (a) price, quality, safety, reliability and security of supply of electricity; and

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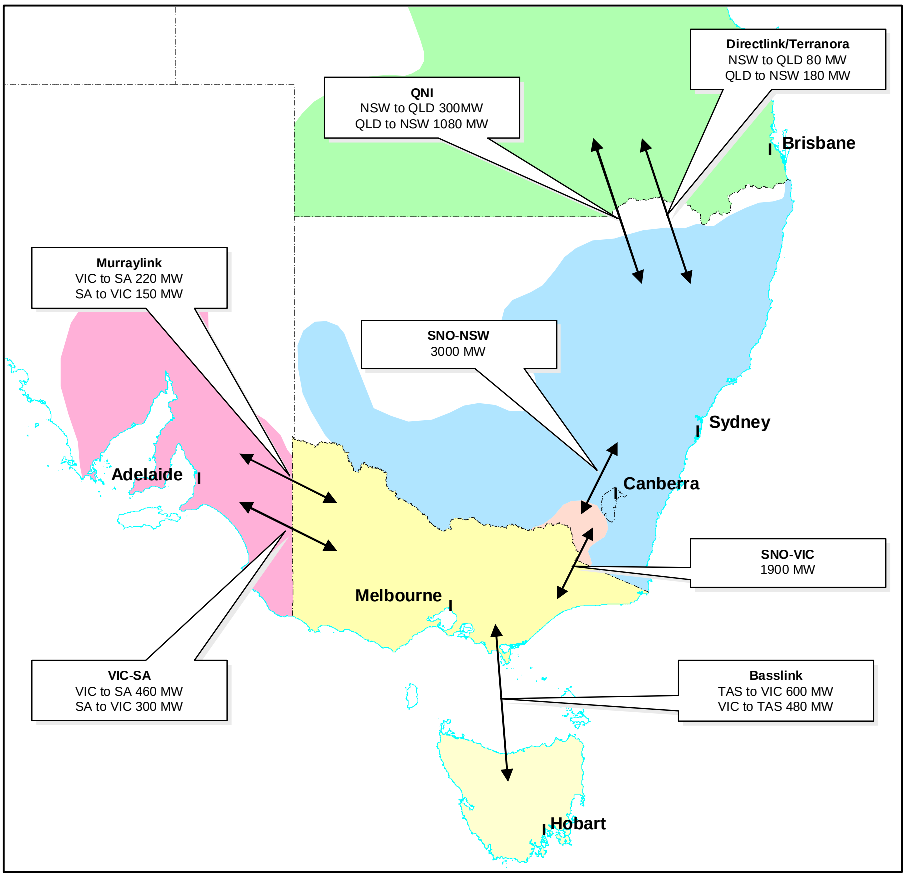
[1] AEMC website, http://www.aemc.gov.au/media.php?article=4

(b) the reliability, safety and security of the national electricity system.

Figure 2.1
Interconnector capacity in the NEM



Source: RLMS and Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p.7-7, annotated by NERA.

The Australian Energy Regulator (AER) is responsible for enforcing and implementing the Rules.[2] In addition, it is responsible for the economic regulation of transmission and distribution services, in accordance with the Rules.

Market structures differ significantly across each NEM region. In Victoria and South Australia government ownership was divested earlier in the reform phase.[3,4] The Queensland region has until recently been characterised by state-owned generation, transmission, distribution and retail companies. The degree of government ownership in Queensland has, however, diminished somewhat following the sale of Energex, Ergon and Enertrade.[5] The

2 AER website, http://www.aer.gov.au/content/index.phtml/tag/aerAboutUs/

3 ESC, Review of Effectiveness of Retail Competition in Gas and Electricity – Public Draft Report, 30 March 2004, p.24.

4 Auditor-General of South Australia, Report for the Auditor-General for the year ended 30 June 2001, asset disposals section.

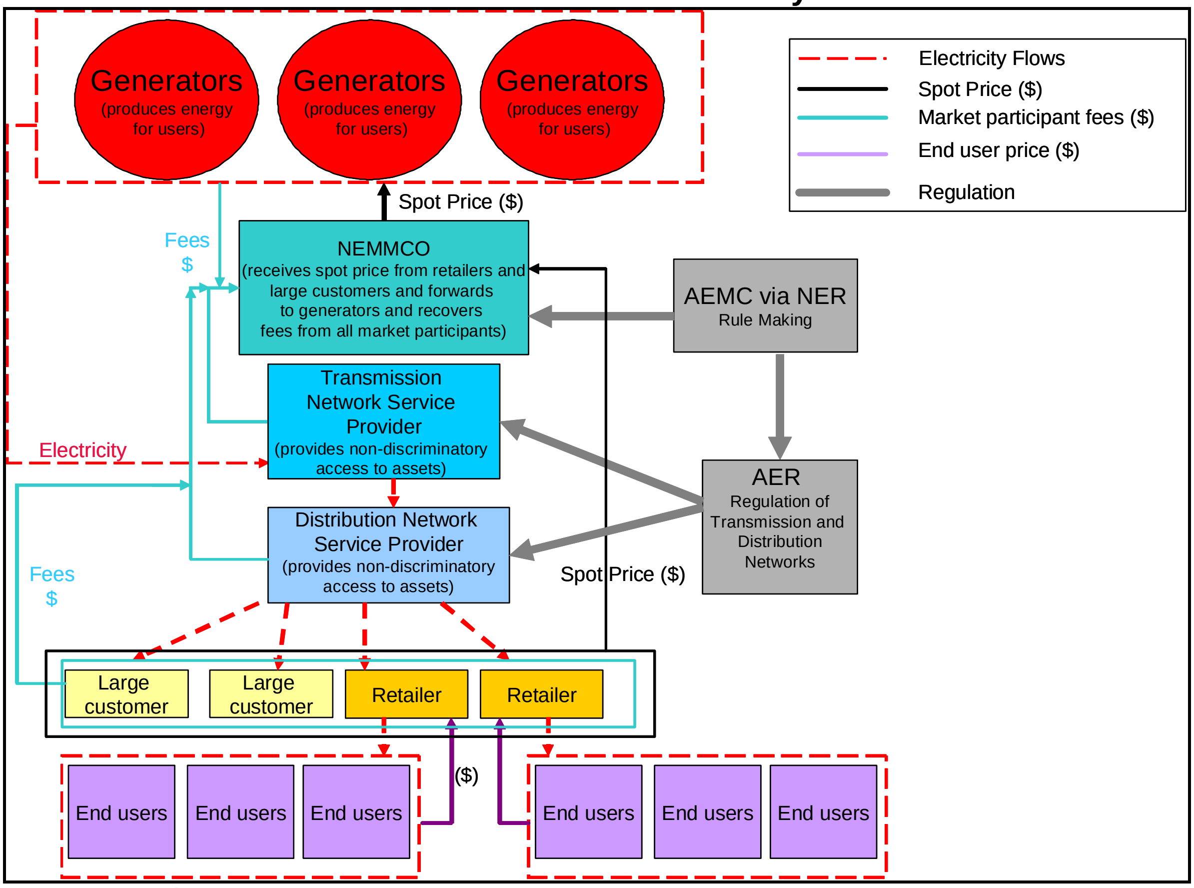
5 Queensland Government, Joint Ministerial Media Statement, 19 February 2007.
Note that only the contestable customers of Ergon were packaged for sale.

New South Wales region has to date been characterised by government ownership across generation, transmission, distribution and retail. Following the release of the Owen Inquiry report, the New South Wales government has indicated its intention to sell the retail components of the integrated electricity utilities and lease out the generators.[6]

2.1. Structure of the NEM

The NEM market participants consist of generators, retailers, large end-users, traders, special participants, transmission network service providers (TNSPs) and distribution network service providers (DNSPs). All market participants are required to be registered with NEMMCO and pay the appropriate fee. Figure 2.2 below provides an overview of the interrelationship between the principal market participants, NEMMCO and the associated regulators discussed above.

Figure 2.2
Structure of the National Electricity Market



Source: NERA analysis

An overview of the principal market participants is provided below.

[6] See Owen Inquiry into Electricity Supply in NSW, September 2007 and Premier of New South Wales, NSW Government acts to secure State's energy supply, 10 December 2007.

Generators

Generators own and operate electricity plants to convert energy from a fuel source into electricity. In Australia, the main fuel types used are coal, water, natural gas and wind. Box 2.1 describes the characteristics of the different types of load these fuel sources dictate and how NEMMCO classifies generators for scheduling purposes.

Box 2.1: Summary of generator characteristics

Base Load generation provides steady power flows into the electricity grid, generally only stopping for repairs and maintenance. Generators are designated as base load given their low cost, efficiency and safety at set output levels. In the NEM coal-fired generation provides the majority of base load generation.

Peaking Load provides supply at times of increased demand. This is due to higher costs of operation and/or shorter start-up times than base load. Peaking power plants vary in their operating times and due to these fluctuations certain equipment and fuels are not desirable for peak plants as the operating conditions would strain the equipment. Gas-fired generation is used for additional supply requirements in peak demand periods in the NEM.

NEMMCO schedules generators based on these characterisations and the capacity they can offer into the interconnected network:

§ *Scheduled generators* have a capacity exceeding 30MW;

§ *Non-scheduled generators* have capacities less than 30MW or can only offer supply on an interruptible basis;

§ *Market generators* have capacity available for sale to the network; and

§ *Non-market generators* have all their output purchased by a local retailer or by a customer at the same connection point.

Source: NEMMCO, Generator Registration Guide, 30 June 2006, p.6 and AGL v ACCC (no.3) Corrigendum, 8 January 2004, paragraph 55.

Coal generation is a process that burns coal to heat a boiler containing water. The heated water evaporates into steam that is then used to turn turbines which generate electricity. There are two types of coal in Australia: black and brown. Black coal is regarded as superior as it provides two to three times more energy than brown coal; however brown coal is generally easier to mine.[7] Larger volumes of brown coal are required to generate the same amount of electricity as black. This higher volume requirement renders brown coal a larger emitter of CO_2 gases.[8]

Coal is the principal fuel source in Australia reflecting the vast quantities available. In 2005 Australia's had 73 billion tonnes of black coal reserves.[9] Black coal is located primarily in

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7 Minerals Council of Australia website, http://www.minerals.org.au/education/primary/primary_resources/envirosmart/case_studies/vic/geology

8 Minchin, Liz, "The dirty state we're in", The Age, 14 February 2005.

9 Australian Coal Association website, http://www.australiancoal.com.au/resources.htm

New South Wales and Queensland. Brown coal is generally found in Victoria, where there is an estimated 53 billion tonnes.[10]

Hydroelectric ('hydro') generation uses energy stored in flowing water to turn a turbine to generate power. Hydro generators can vary in size from large installations associated with dams on large rivers, such as with the Snowy Hydro Scheme, or micro generators fixed to in-stream weirs as part of the rural or urban water system. Hydro generation is the second largest proportion of total generation capacity in the NEM.[11]

Natural gas-fired generators turn turbines in one of two ways to produce electricity.[12] Open cycle gas turbines (OCGT) burn gas mixed with air to rotate a turbine without a steam intermediary. Combined cycle gas turbines (CCGT) extend this process by using the gas turbine exhaust to heat a boiler that releases steam into a second turbine. Natural gas plants produce comparatively smaller volumes of CO_2 than their coal fired counterparts.[13] However, due to the relatively high cost of natural gas, especially compared with coal, they are generally operated only during peak demand periods, when the market price is at its highest.

Wind generation utilises modern versions of windmill propellers to turn a turbine directly for electricity generation. A significant drawback however is that it relies on an intermittent source of energy and so cannot be relied upon to supply at required periods. However, significant recent increases in wind generating capacity spurred by the Federal Government's MRET has led the MCE to consider better scheduling processes to incorporate this intermittent source.[14]

The NEM operates a gross pool market and thus generators are required to sell their entire electricity output through the spot market.[15] The NEM is also an 'energy-only market', in that the revenue earned by generators is a function of the quantity of electricity it sells and not the capacity of its plant. In the absence of a separate capacity market or a capacity payment mechanism, holding additional capacity is only profitable if, when the capacity is dispatched, it is dispatched at a price that exceeds its marginal cost.

To limit its exposure to the spot market a generator can enter into hedge contracts directly with retailers and/or large customers. In addition to limiting its exposure to the spot market, the use of derivatives may provide the revenue required to maintain reserve capacity, as discussed below in section 7.2.1. The absence of a capacity payment mechanism in the energy-only market model denotes that investment in additional generation will be

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10 Department of Industry, Tourism and Resources, Regional Minerals Program (RMP): Report – Latrobe Valley 2100 Coal Resources Project, last reviewed 19/12/06.

11 Electricity Gas Australia (2007), ESAA.

12 Met Office, UK, http://www.metoffice.gov.uk/consulting/casestudies/06_0281c_DSheet_3.pdf

13 Roarty, M., "Natural Gas: Energy for the New Millennium", Parliamentary Library Research Paper 5 1998-99, Parliament of Australia, (1998).

14 MCE SCO Wind Energy Policy WG, "Integrating Wind Farms into the National Electricity Market: Discussion Paper", March 2005.

15 A gross pool market does not permit participants to contract directly with each other for the physical delivery of a good. In the NEM, NEMMCO aggregates the entire production of electricity into a pool from which retailers and large market customers can purchase their electricity requirements.

inextricably linked to a generator's expectations about future spot prices and the degree to which exposure to those prices can be mitigated.[16]

Capacity and output also affect the fees generators pay as participants in the NEM. Fees are structured such that 50 per cent of the charges are allocated on the basis of energy supplied in the previous calendar year, whilst the remaining 50 per cent is levied based on the higher of a generators' registered capacity or notified maximum capacity.[17]

Network service providers

The electricity network consists of high voltage transmission lines that transport electricity from generators to consumers via a local distribution network. This network structure reflects the economies of scale associated with large scale electricity generation, compared with localised generation. Generators can also be embedded within distribution networks, both as a way of providing additional electricity during peak periods, but also to address network congestion problems.[18] Distributed generation is projected to increase over 100 per cent by the year 2020.[19]

TNSPs provide access to the high-voltage cables that move electricity from large generators to load centres. Transmission networks operate at high voltages to allow for the movement of a greater amount of electricity for a given size, compared to local distribution networks.[20] As well, the higher voltages minimise losses in the network.[21]

DNSPs receive electricity from the transmission network and transform it to lower voltages that are more suitable for use by electricity consumers. They are responsible for the operation and maintenance of their local distribution network. Both TNSPs and DNSPs are responsible for maintaining system security on their portion of the network and facilitating new connections.

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16 NEMMCO, *Australia's National Electricity Market: Wholesale Market Operations*, p. 8.

17 NEMMCO, Structure of Participant Fees - Final Determination and Report 2006, p. 5-6.

18 PB Associates, A National Code of Practice for Embedded Generation Consultation Paper, February 2006, pp 6-7.

19 MCE SCO R&DG WG, "Impediments to the Uptake of Renewable and Distributed Energy: Discussion Paper", February 2006, p.15.

20 ActewAGL, http://www.actewagl.com.au/education/Energy/Electricity/ElectricityDistribution/default.aspx

21 Western Power, http://www.worldofenergy.com.au/factsheet_electricity/07_fact_electricity_transmission.html

Retailers and large end users

Retailers act as the intermediary between generators and smaller electricity consumers, such as households and small businesses. They purchase electricity from the NEM pool and on-sell to customers charging a price that reflects the generation, transmission and distribution costs, as well as its own retail costs. Large end users participate directly in the NEM by purchasing their own electricity requirements from the pool.

Retail competition has been introduced progressively across the regions such that retailers are able to service customers throughout the NEM. The MCE has agreed that once effective competition exists, these default regulated tariffs will be removed.[22]

The electricity costs incurred by retailers and large end-use customers are subject to the volatility of the spot market. To ameliorate this exposure, hedge contracts may be entered into directly with generators coinciding with a generator's interest to avoid undue volatility. Alternatively, a large customer may elect to withdraw from the market if it considers the spot price to be higher than the short-run costs of not using electricity, and enter again only when the price falls below that level.

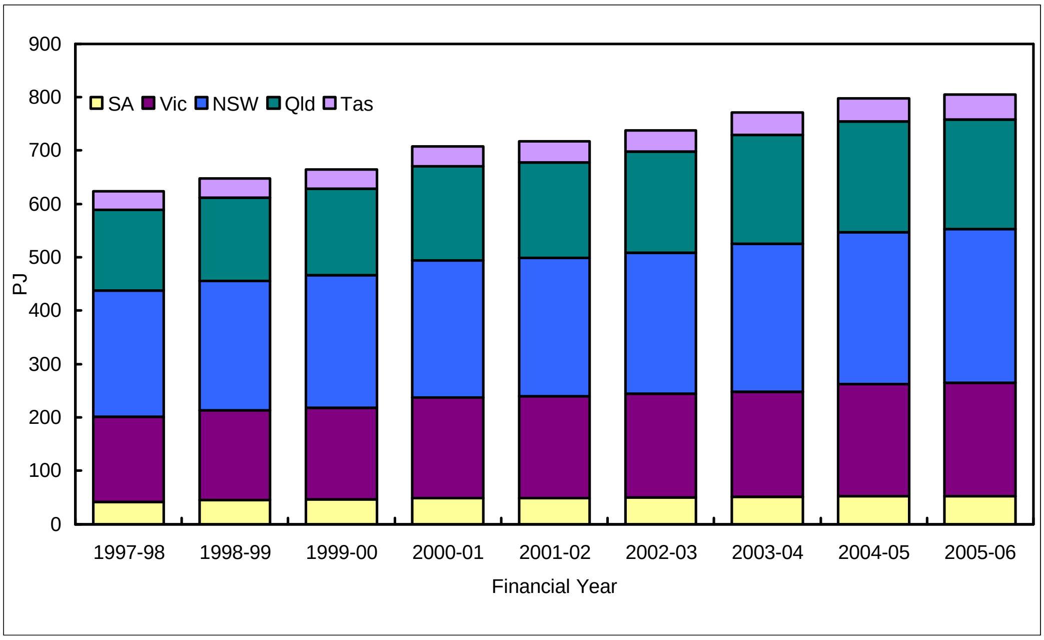
2.2. Electricity consumption in the NEM

Since the commencement of the NEM, electricity consumption has increased approximately 29 per cent, at an average annual growth rate of 3.4 per cent. This average annual growth rate has varied across each region with Queensland having the highest of 4.0 per cent (with Victoria closely topping as well at 3.9 per cent), and New South Wales and South Australia the lowest, at 2.6 and 2.8 per cent respectively.

The elevated growth in Queensland has resulted in it passing Victoria as the second largest consumer of electricity in 2003-04; however in 2004-05 and 2005-06 Queensland is slightly below Victoria in terms of shares of electricity consumed. Figure 2.3 and Figure 2.4 below show consumption patterns across the NEM over time.

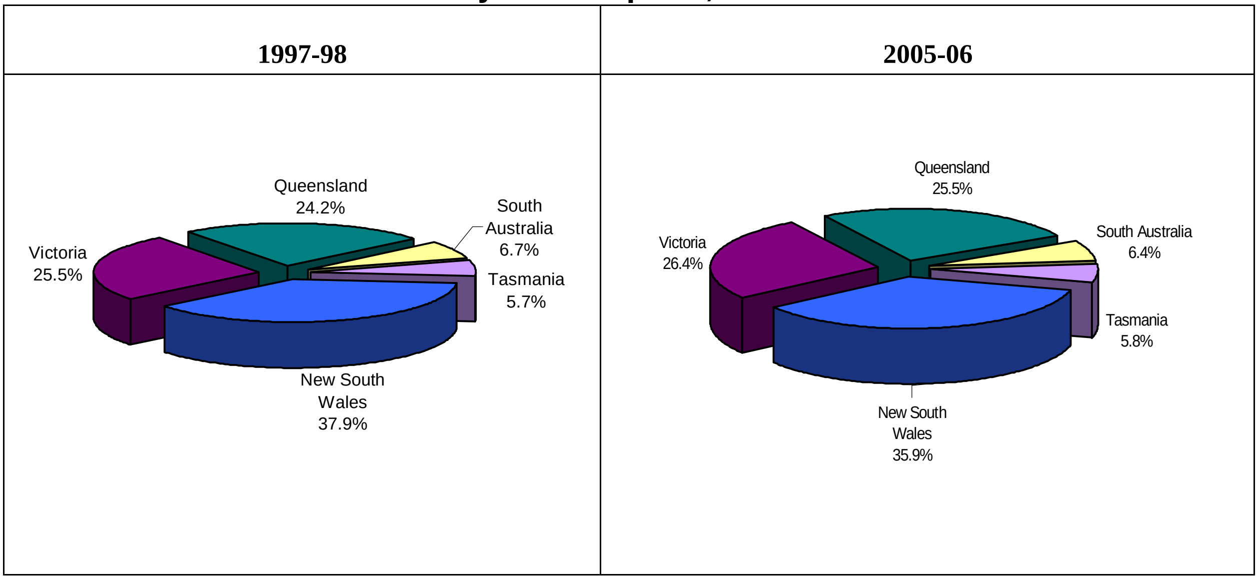
[22] Australian Energy Markets Agreement, clause 14.11.

Figure 2.3
Australian consumption of electricity by State, 1997-98 to 2005-06



Source: ABARE.

Figure 2.4
Share of electricity consumption, 1997-98 and 2005-06



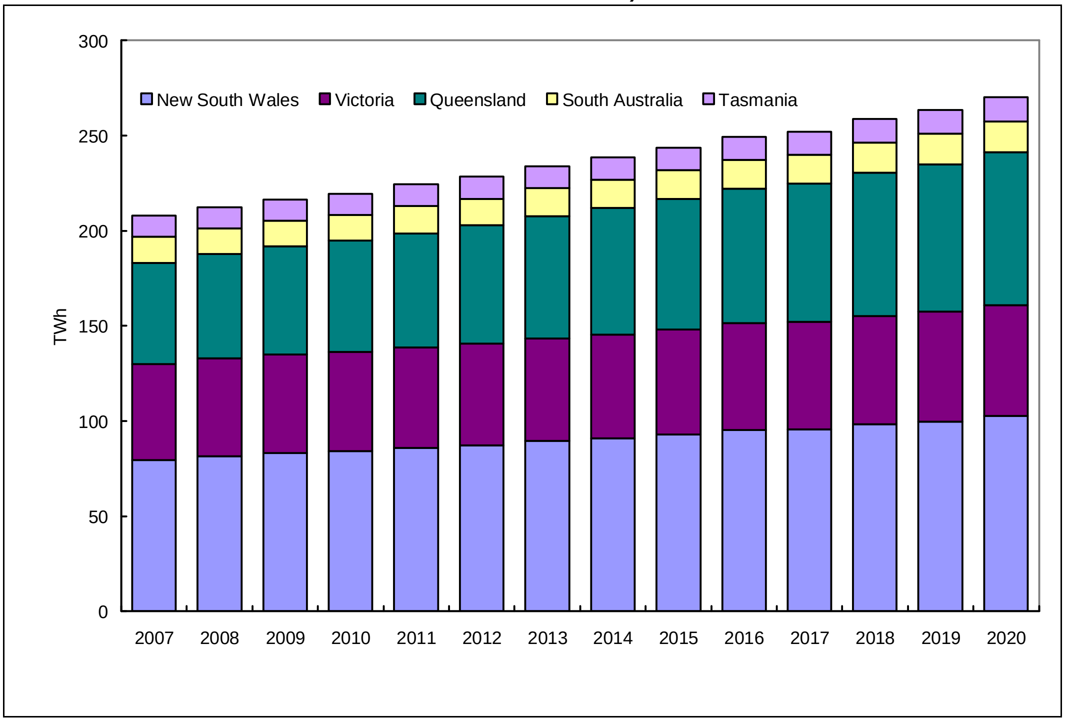
Source: ABARE.

Queensland electricity demand has also been forecast to continue exhibiting strong growth. Core Collaborative has released its forecasts for terminal electricity consumption[23] for the period 2007 to 2020. It estimates that demand is expected to grow from 207.9 TWh in 2007 to 270 TWh in 2020. Most of this growth is expected to occur in Queensland, followed by

23 Terminal electricity consumption excludes electricity expended during the generation process and any losses occurring on the network (Core Collaborative, 2020 Electricity Outlook, p.6-7).

increases in New South Wales, South Australia, Victoria and Tasmania. Figure 2.5 below illustrates these projections.

Figure 2.5
Forecast terminal demand, 2007 to 2020



Source: Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. 6-7.

2.3. Prices in the NEM

2.3.1. Regional differences

As the NEM is divided into regions, the price of the highest bid required to meet demand in that region dictates the 30 minute clearing price. Thus, spot prices can vary between each region reflecting the underlying differences in the supply and demand balance. To consider the variation in prices, we have presented in Table 2.1 the average yearly regional spot price for the period 2002 through February 2008.

Table 2.1
Average yearly regional spot price, 2002 to 2008 ($/MWh)

Year	NSW	Qld	SA	Snowy	Tas	Vic
2002	40	48	35	36		33
2003	26	23	27	24		23
2004	45	35	42	41		30
2005	36	25	34	28	101	26
2006	31	26	39	31	36	34
2007	67	67	58	64	57	63
2008 (Jan – Feb)	31	88	123	38	52	39

Source: NERA analysis – annual average taken from average daily; NEMMCO data.

It can be observed in the above table that the average spot price for electricity in each region varies considerably across the NEM. In particular, Tasmania experienced a price of electricity that was twice as high as the other regions prior to the establishment of the Basslink interconnector.

Table 2.2 below presents the standard deviation[24] of the average daily price for each region on an annual basis. These results demonstrate that the variability of spot prices can differ substantially between regions. For example, in 2004 the price of electricity was distributed in a much wider range around the mean in New South Wales compared to South Australia, despite the observation that the average price of electricity only differed by $3 per MWh.

Table 2.2
Average yearly standard deviation of spot prices, 2002 to 2008 ($/MWh)

Year	NSW	Qld	SA	Snowy	Tas	Vic
2002	42	85	27	29		27
2003	42	30	16	27		22
2004	118	67	54	84		23
2005	83	47	27	36	228	21
2006	65	47	38	34	18	47
2007	86	79	52	69	32	88
2008 (Jan – Feb)	7	259	399	24	12	22

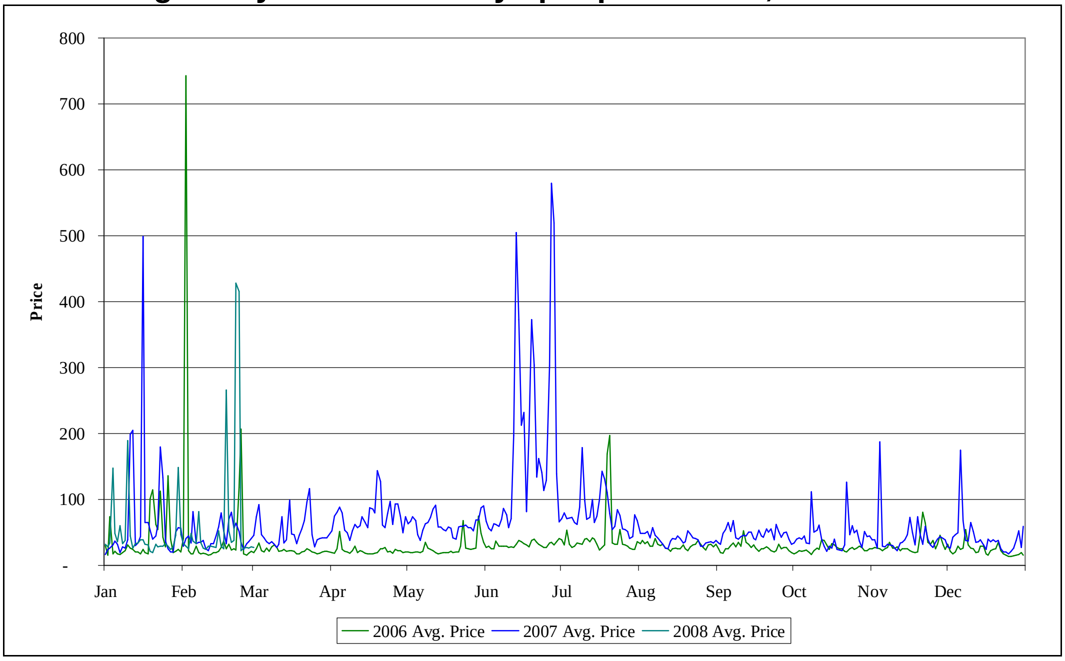
Source: NERA analysis; NEMMCO data.

[24] The standard deviation is a measure of the statistical dispersion of a data set which represents how tightly clustered the data set is around the mean.

2.3.2. Price growth

Figure 2.6 shows the average daily price of electricity for the entire NEM.[25] The average spot price in 2007 is, for the most part, higher than the average price over the corresponding period in 2006. In particular, over March and April the difference in the price of electricity between the two years has grown considerably, with the price in 2007 trending towards $100 per MWh, whilst the 2006 price consistently remained below $30 per MWh except for one day in February.[26]

Figure 2.6
Average daily NEM electricity spot price: 2006, 2007 and 2008



Source: NEMMCO.

2.3.3. Volatility

Following deregulation, electricity markets around the world have exhibited significant levels of price volatility.[27] This is particularly the case in Australia. For instance in Victorian the spot price for electricity since January 2006 has exhibited extreme volatility, falling to a low of -\$100 per MWh and reaching the maximum \$10,000 per MWh.

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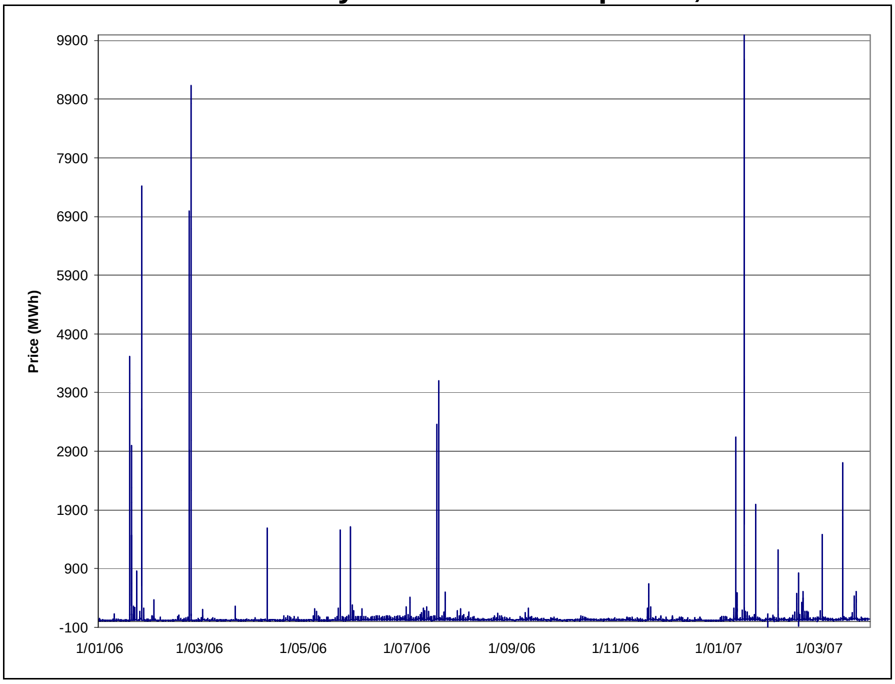
25 This is calculated by determining the value of all NEM trades in each region for every day and dividing the total value by the total level of NEM demand.

26 This analysis is replicated in Appendix 1 on a region by region basis.

27 Anderson, Edward J, Xinmin Hu and Donald Winchester, "Forward contracts in Electricity Markets: The Australian Experience", Centre for Energy and Environmental Markets, 2006.

Figure 2.7
National Electricity Market interval prices, Victoria



Source: NEMMCO

Examining this chart it is apparent that the greatest amount of volatility occurs during periods of extreme weather such as the summer months of December through to February, when air conditioners are in use, and the winter months of May through July, when space heaters are utilised.

2.3.4. AER price monitoring role

In accordance with clause 3.13 of the Rules the AER is required to monitor significant variations between forecast and actual prices. One key aspect of this monitoring role is set out in clause 3.13(d) which requires the AER to prepare a report when the spot price exceeds $5,000/MWh in a trading interval. The content of this report must:

§ Describe the significant factors contributing to the spot price exceeding $5,000/MWh;

§ Assess whether rebidding contributed to the spot price exceeding $5,000/MWh; and

§ Identify the marginal scheduled generating units and all scheduled generating units for which any dispatch offer was equal to, or greater than, $5,000/MWh and compare this to dispatch offers in previous trading intervals.

Since taking on this role the AER has published 19 reports with four published in 2005, six in 2006, eight in 2008 and one in the first three months of 2008. The table below provides a summary of the reviews the AER has undertaken in each region since 2005.

Table 2.3
AER reviews of spot prices in excess of $5,000/MWh

Year	NSW	Qld	SA	Snowy	Tas	Vic
2005	31 Oct 9 & 10 Nov 7 Dec	7 Dec	30 Nov	n.a.	n.a.	n.a.
2006	2 Feb 20 Jul	3 Jan 2 Feb	26 Jan	n.a	23 May	26 Jan 23 & 24 Feb
2007	11 Jan 12 – 28 Jun 22 Oct	23 Jan 24 Jan 12 – 28 Jun 4 Nov	16 Jan 31 Dec	12 – 28 Jun	n.a	16 Jan
2008 (Jan – Feb)	n.a	n.a	4 & 10 Jan 18-19 Feb	n.a	n.a	n.a

Source: AER website.

The most recent review of spot prices exceeding $5,000/MWh was published by the AER on 3 March 2008. This review was prompted by spot prices in South Australia exceeding $5,000/MWh on 4 January, 10 January, 18 February and 19 February. In its review of this event, the AER considered whether rebidding played any role in the spot price movement. The AER concluded that some of the rebidding by AGL (operator of the Torrens Island generation plant) had the effect of increasing prices whilst others reduced prices.[28] The AER noted that it intended to undertake a further investigation to assess AGL's compliance with the good faith provisions of the NER.[29]

28 AER, Spot Prices greater than $5000/MWh, March 2008, p. 4.

29 AER, Spot Prices greater than $5000/MWh, March 2008, p. 6.

3. Generation, transmission and distribution in the NEM

In the following sections we provide an overview of the generation, transmission and distribution functions of market participants with particular emphasis placed on:

§ identifying generation capacity, by ownership and fuel type in each NEM region;

§ total electricity supply, within each region or imported/exported outside the region; and

§ providing a brief overview of transmission and distribution network service providers in each region.

3.1. NEM structure in aggregate

3.1.1. Generation

As at 1 January 2008 total generation capacity in the NEM was 45 GW. According to information published by the ESAA 61 per cent of the total NEM capacity as at 1 January 2008 is fuelled by coal, 17 per cent is fuelled by hydro and 16 per cent is fuelled by natural gas.[30] The capacity provided by these fuel types has been supplemented by the expansion of non-scheduled generation into the market, particularly wind generation.[31] The high costs associated with starting up coal fired power generators means that these plants tend to operate as base load generators while generators using other fuels, such as natural gas, tend to be used to meet peak demand.

Table 3.1
Generation capacity by fuel type, NEM aggregate as at 1 Jan 2008

Fuel type	Capacity (GW)	Capacity (%)
Coal	28.0	61%
Hydro	7.8	17%
Natural gas	7.2	16%
Other[32]	0.7	2%
Oil products	0.6	1%
Wind	0.8	2%
Total capacity	**45.0**	**100%**

Source: Electricity Gas Australia (2007), ESAA

3.1.1.1. Fuel type

Using data published by the ESAA for the financial year 2005/06 it is possible to compare the contribution made by each fuel type to capacity within the NEM to the contribution made to actual energy supplied over that financial year. Figure 3.1 illustrates the difference between

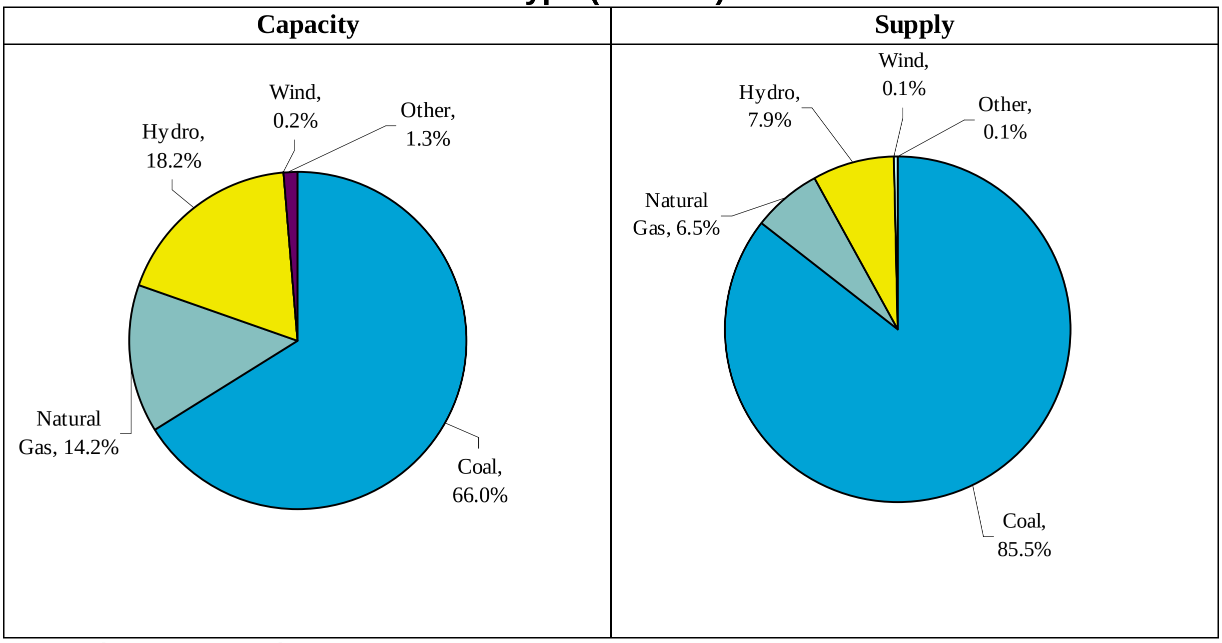
[30] This capacity includes new generation plants commissioned in Queensland (750 MW Kogan Creek, 450 MW Braemer and 27.4 MW Daandine), New South Wales (60 MW Liddel Upgrade), Victoria (320 MW Laverton North), Tasmania (108 MW Bell Bay).and the 60 MW Liddel upgrade, commissioned in October 2006.

[31] NEMMCO, Semi-Dispatch of Significant Intermittent Generation: Request for Rule Change, 23 April 2007, p.5.

[32] The “Other” category varies from region to region and is discussed in the individual region sections below.

these measures. Examining these charts it is apparent that while coal fired power generation accounted for over 66 per cent of total capacity in the NEM in 2005/06 it was responsible for supplying 85 per cent of the NEM's scheduled electricity requirements over this financial year. In contrast hydro generated electricity accounted for over 18 per cent of capacity but was responsible for supplying less than 8 per cent of scheduled electricity requirements over 2005/06. Similarly, natural gas fuelled generation accounted for over 14 per cent of capacity but was responsible for supplying less than 7 per cent of scheduled electricity over 2005/06.

Figure 3.1: NEM scheduled generation capacity and electricity supplied by fuel type (2005/06)



Source: Electricity Gas Australia (2007), ESAA

3.1.1.2. Ownership interests

In terms of the ownership of the generating assets, a number of state governments privatised their electricity generation assets as part of the energy reform process. This included the corporatisation of state-owned electricity entities and vertical separation of the elements within the electricity supply chain. Both Victoria and South Australia adopted the privatisation model whilst New South Wales and Queensland corporatised the state owned utilities. Currently, approximately 60 per cent of total generation capacity is provided by government owned and operated generators.[33]

3.1.1.3. Interconnection

Whilst most electricity in each region is sourced from within that region, increasing interconnection between regions has led to some regions with over capacity exporting energy to regions with insufficient capacity. New South Wales and South Australia are consistent

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[33] Electricity Gas Australia (2007), ESAA.

importers of electricity while Queensland, Victoria and the Snowy region tend to be exporters of electricity.[34]

The trading of electricity across NEM regions is facilitated by interconnectors. An interconnector is a high-voltage line connecting two regions. Table 3.2 provides a summary of the interconnector capacities and flows between the NEM regions.

Table 3.2
Interconnector capacity and throughput (GWh)

Interconnector	Capacity (MW)	2003/2004	2004/2005	2005/2006
New South Wales to Queensland (QNI)				
New South Wales to Queensland	589	85	68	64
Queensland to New South Wales	1078	4013	4609	5562
New South Wales to Queensland (Terranora)[35]				
New South Wales to Queensland	30			0
Queensland to New South Wales	234			258
New South Wales to Snowy				
New South Wales to Snowy	1150	285	240	491
Snowy to New South Wales	3559	3735	4167	3898
Victoria to Snowy				
Victoria to Snowy	1313	2121	1878	1507
Snowy to Victoria	1842	2200	1800	3048
South Australia to Victoria (Heywood)				
South Australia to Victoria	300	31	59	38
Victoria to South Australia	460	2502	2170	2325
South Australia to Victoria (Murraylink)				
South Australia to Victoria	214	72	44	32
Victoria to South Australia	220	222	310	276
Tasmania to Victoria (Basslink)[36]				
Tasmania to Victoria	600			152
Victoria to Tasmania	480			133

Source: Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p.7-7 and Electricity Gas Australia (2007), ESAA

In general, electricity will flow from a low priced region to a high priced region, reflecting the differences in underlying supply and demand. However, the interconnectors have a limited capacity that at times may lead to constraints.[37] This is illustrated in the table below.

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34 Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. 7-7.

35 Terranora is the new name for Directlink as a regulated interconnector.

36 Basslink began operation as a market network service provider on 28/4/06.

37 Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. 4-5.

Table 3.3
Hours of system normal binding constraints

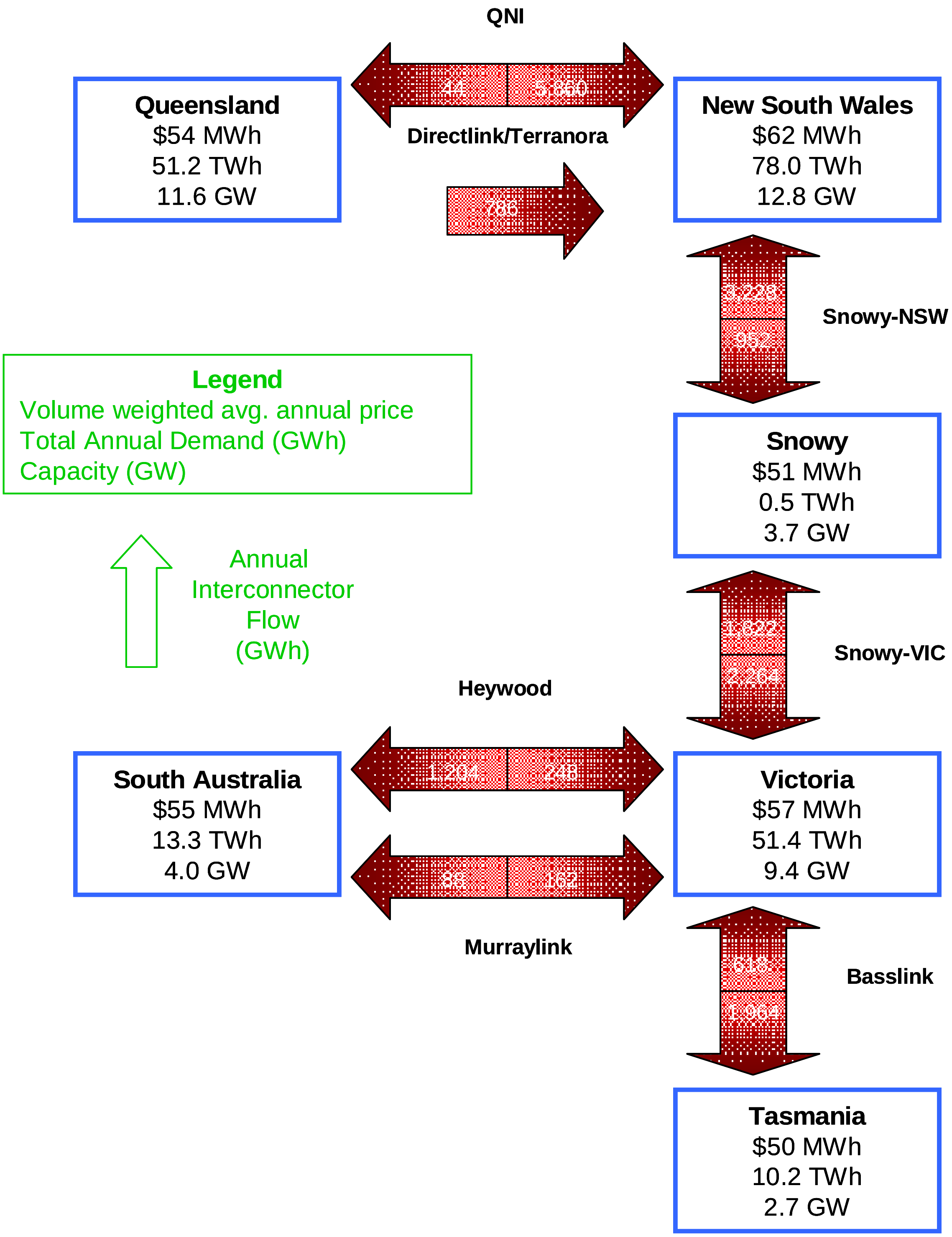
Interconnector	Avg limit when constrained (MW)	Hours of constrained flow
New South Wales to Queensland (QNI)		
New South Wales to Queensland	372	19
Queensland to New South Wales	1037	162
New South Wales to Queensland (Terranora)		
New South Wales to Queensland	-81	28
Queensland to New South Wales	186	19
New South Wales to Snowy		
New South Wales to Snowy	-195	24
Snowy to New South Wales	2336	37
Victoria to Snowy		
Victoria to Snowy	772	8
Snowy to Victoria	1314	50
South Australia to Victoria (Heywood)		
South Australia to Victoria	291	12
Victoria to South Australia	451	273
South Australia to Victoria (Murraylink)		
South Australia to Victoria	-6	21
Victoria to South Australia	175	24
Tasmania to Victoria (Basslink)		
Tasmania to Victoria	-118	52
Victoria to Tasmania	-120	134

Source: ESAA 2007

It is apparent from the table above that the Queensland to New South Wales and Victoria to South Australia flows are the most significant source of constraint, as represented by the hours of constrained flow.

A summary of generation capacity, electricity demand, the weighted average annual prices and interconnector flows for each region is provided in Figure 3.2 below.

Figure 3.2
Snapshot of the National Electricity Market, 2006-07[38]



[38] This figure is similar to one published in ABARE's "Energy in Australia 2007". The capacities in our snapshot are generally somewhat higher than ABARE's, reflecting the fact that we have used more current information on generation capacity. Additionally we have sourced the annual interconnector flows from NEMMCO' 2007 Statement of Opportunities.

3.2. New South Wales and the Australian Capital Territory

3.2.1. Generation

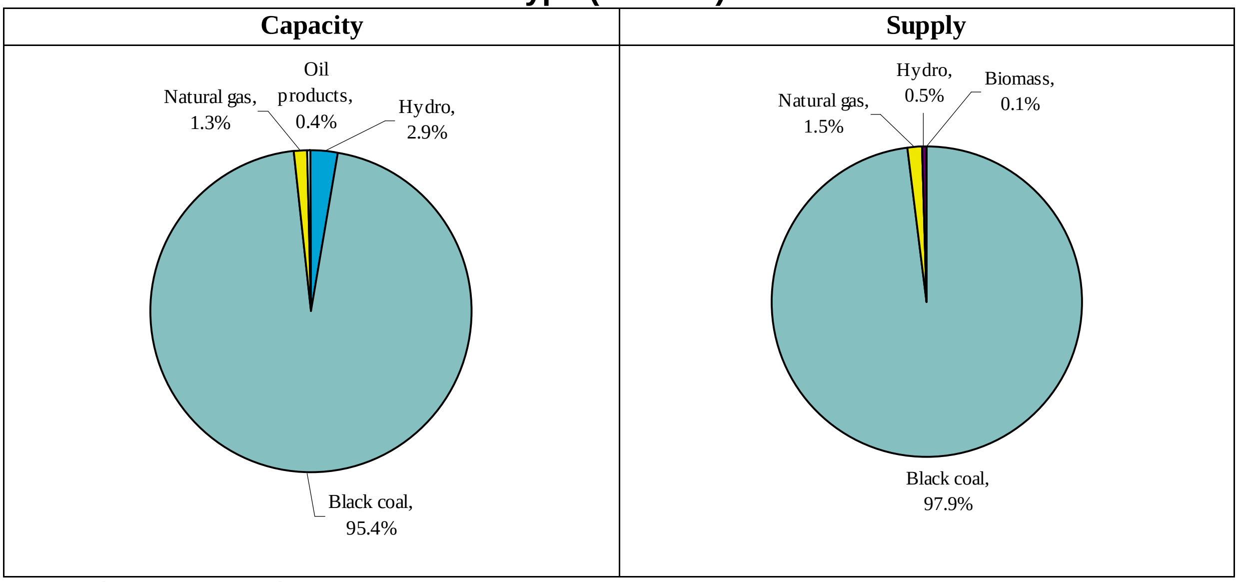
As at 1 January 2008 total generation capacity in New South Wales was 12.8 GW,[39] which represents 28 per cent of total NEM capacity.

3.2.1.1. Fuel type

According to data published by the ESAA over 95 per cent of total capacity in the state was provided by black coal-fired generators over 2005/06 with coal supplied from five major coalfields in the Sydney-Gunnedah Basin.[40] The prevalence of existing coal-fired generation in New South Wales has left only a limited role for other fuels such as hydro, gas and renewable energy (see Figure 3.3).

Despite only accounting for 95 per cent of capacity over 2005/06, coal fired generators supplied nearly 98 per cent of the electricity generated by scheduled generators in New South Wales. In contrast hydro generated electricity accounted for approximately 3 per cent of capacity but accounted for just 0.5 per cent of electricity scheduled in 2005/06 (see Figure 3.3).[41]

Figure 3.3: NSW scheduled generation capacity and electricity supplied by fuel type (2005/06)



Source: Electricity Gas Australia (2007), ESAA

3.2.1.2. Ownership interests

Table 3.4 provides a summary of the generators operating in New South Wales and the capacity controlled by those generators as at 1 January 2008. As can be seen from this table

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39 This capacity also includes the 60 MW Liddel upgrade, commissioned in October 2006.

40 The Sydney-Gunnedah Basin extends from the south of Wollongong to north of Newcastle and north-westerly through Narrabri into Queensland.

41 Scheduled generators accounted for 95% of capacity in the NEM and supply 97% of electricity with the remainder supplied by embedded and non grid generators. ESAA 2007.

Macquarie Generation, Delta Electricity, and Eraring Energy are the three largest generators in New South Wales. These three generators are currently owned by the New South Wales Government although the New South Wales Government has noted its intention to lease existing generation assets to private companies following the release of the Owen Inquiry's report into Electricity Supply in NSW in September 2007.[42]

Table 3.4
NSW generation capacity by owner as at 1 January 2008

Operating company	Capacity (GW)	Capacity (%)
NSW government	12.0	93.7%
- Macquarie Generation	*4.8*	*37.1%*
- Delta Electricity	*4.2*	*33.1%*
- Eraring Energy	*3.0*	*23.3%*
- Country Energy	*0.0*	*0.1%*
Marubeni[43]	0.2	1.3%
Babcock & Brown Power[44]	0.2	1.2%
Other interests[45]	0.5	3.9%
Total capacity	**12.8**	**100**

Source: Electricity Gas Australia (2007), ESAA and other sources as footnoted.

Total energy supplied by New South Wales generators into the NEM for the year ending 30 June 2006 was over 80 TWh, representing 34 per cent of total NEM electricity supply. Table 3.5 provides a summary of the sources of electricity supplied into New South Wales over 2004/05 and 2005/06 and illustrates the share of the market accounted for by each of the principal generators measured on the basis of electricity supplied.

[42] Premier NSW, *NSW Government acts to secure State's energy supply*, Dec 2007.

[43] Marubeni recently acquired Sithe Energies Asia Pacific power assets which includes the 160MW Smithfield CCGT plant. Marubeni website http://www.marubeni.com/news/2003/031022e_b.html.

[44] Redbank power station is wholly owned by Babcock & Brown Power.
Babcock & Brown Power website, http://www.bbpower.com/bbp-assets/redbank.aspx.

[45] This category includes One Steel's facility at Port Kembla (61.7 MW, waste gas) , Tower (41.2MW, coal waste methane) and Appin (55.6MW, coal waste methane), Snowy Hydro's 80MW and a number of power stations with a capacity less than 25MW.

Table 3.5
NSW electricity supply market share

Operating company	2004/05 (%)	2005/06 (%)
NSW government	83.2	81.7
- Macquarie Generation	*36.4*	*34.8*
- Delta Electricity	*29.8*	*28.9*
- Eraring Energy	*16.9*	*17.9*
Imports from QLD	6.2	7.3
Snowy Hydro	5.9	6.7
Imports from Vic	2.1	1.7
National Power	1.4	1.3
Marubeni	1.3	1.3
Total electricity supplied	**77,353 GWh**	**80,453 GWh**

Source: Electricity Gas Australia (2007), ESAA

On the information contained in the table above it is clear that New South Wales is a significant importer of electricity with over 14 per cent of electricity supplied from other regions over 2005/06,which has increased since the previous year.[46]

Figure 3.4 identifies the location of all generation capacity in excess of 200MW, including the transmission lines that connect these units with distribution centres. These eight generators represent more than 93 per cent of total generation in the state.[47] In October 2006 the Liddell coal fired plant was upgraded with an additional 60 MW capacity. Prior to this the most recent expansion of capacity occurred in 2001 with the commissioning of the 150MW Redbank coal tailing powered station, although additional capacity is currently under construction as discussed below in section 3.8.

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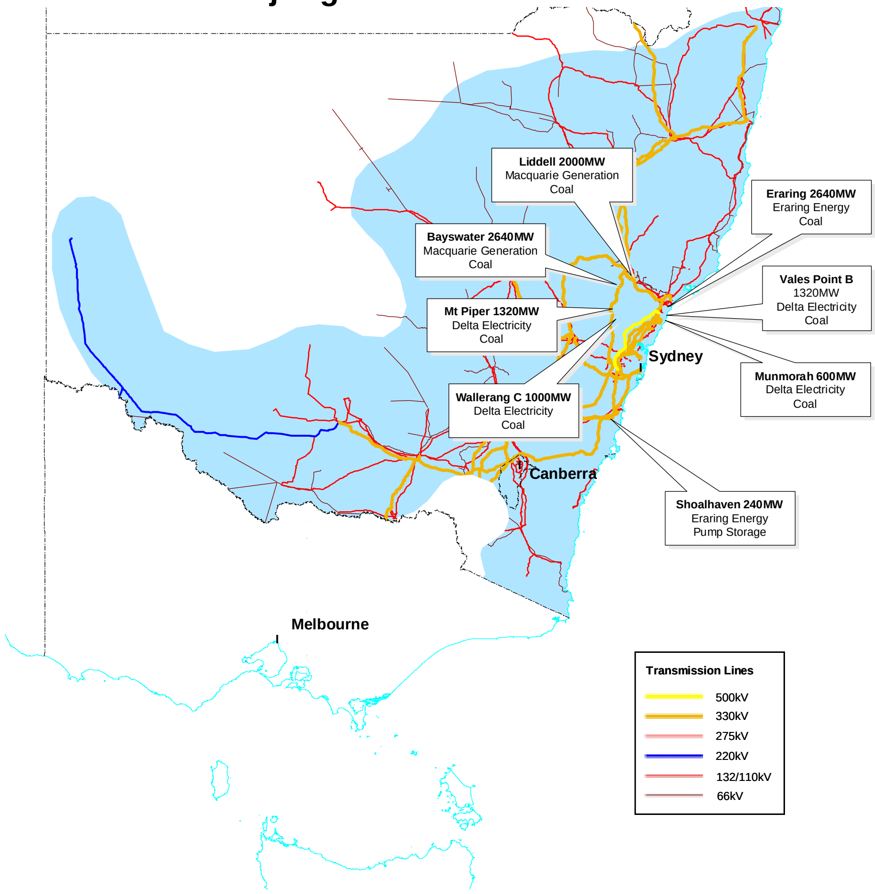
[46] Core Collaborative, 2020 Electricity Outlook, 2007, p.7-7.

[47] Electricity Gas Australia (2006), ESAA.

Figure 3.4
Location of major generation in New South Wales



Source: RLMS, annotated by NERA.

3.2.2. Transmission and distribution

The entire high voltage transmission network in New South Wales is owned and operated by TransGrid. TransGrid is a state-owned corporation that is responsible for the operation of the 12,000 kilometre network.[48]

Distribution in New South Wales is divided between three state-owned corporations: EnergyAustralia, Integral Energy, and Country Energy. EnergyAustralia operates a network of approximately 22,275 square kilometres in the Sydney, Central Coast and Hunter regions.[49] Integral Energy covers, among other areas, Sydney's Greater West, the Southern Highlands and the Illawarra, an area of some 24,500 square kilometres.[50] Australia's largest electricity network of 195,000 kilometres of powerlines is operated by Country Energy which

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48 TransGrid website, http://www.transgrid.com.au/

49 EnergyAustralia website, http://www.energy.com.au/energy/ea.nsf/Content/NSW+Who+is+EnergyAustralia

50 Integral Energy website, http://www.integral.com.au/wps/wcm/connect/integralenergy/NSW/NSW+Homepage/ourNetworkNav/Our+network+area/Our+network+area.html

services the remaining, predominately regional, areas of New South Wales, covering approximately 95 per cent of the state's land mass.[51]

The distribution network in the Australian Capital Territory is owned and operated by ActewAGL, a joint venture between Actew, an Australian Capital Territory government owned corporation and Singapore Power International.

[51] Country Energy website, http://www.countryenergy.com.au/internet/cewebpub.nsf/Content/AboutUs_cover

3.3. Queensland

3.3.1. Generation

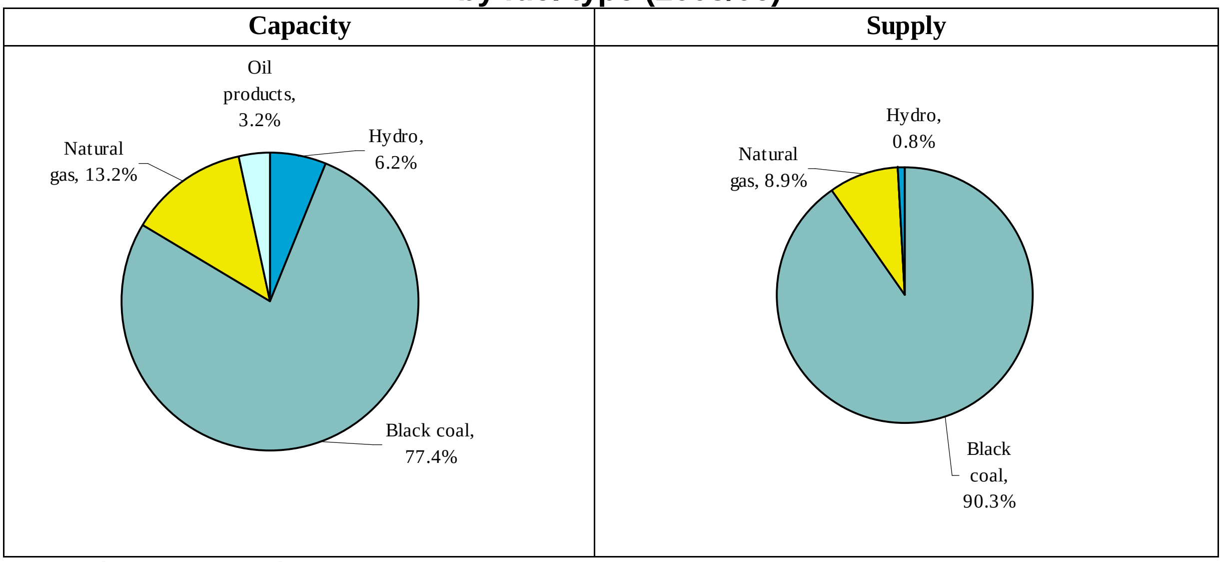
As at 1 January 2008 total generation capacity in Queensland was 12.4 GW,[52] which represents 28 per cent of NEM capacity.

3.3.1.1. Fuel type

According to data published by the ESAA black coal[53] accounted for approximately 77 per cent of capacity over 2005/06. Of the remaining 23 per cent natural gas accounted for 13 per cent, hydro 6 per cent and oil products the remaining 3 per cent. Following the introduction of the Queensland Gas Scheme a number of gas-fired power generation plants have been either constructed (including the 450MW Braemar gas plant) or have been proposed. This scheme is expected to result in a significant increase in the amount of electricity produced using natural gas.[54]

Although coal fired generators accounted for 77 per cent of capacity over 2005/06 it accounted for 90 per cent of electricity supplied in the year. Hydro generated electricity accounted for less than 1 per cent of electricity supplied over the year (compared to 6 per cent of capacity) and natural gas accounted for less than 9 per cent of electricity supplied (compared to 13 per cent of capacity).

Figure 3.5: Queensland scheduled generation capacity and electricity supplied by fuel type (2005/06)



Source: Electricity Gas Australia (2007), ESAA
Note: It should be noted that these figures do not include the 450 MW gas fired Braemar plant and 27 MW gas fired Daandine Power Project which were commissioned after 30 June 2006.

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52 This includes the 750 MW Kogan Creek coal fired plant which was commissioned by CS Energy in late 2007.

53 Queensland's coal reserves are largely located in the Bowen Basin that extends south from Collinsville to Blackwater and Moura, and at Newlands, Blair Athol and near Brisbane

54 In August 2006 the 450MW Braemar natural gas plant, owned by Babcock & Brown Power, was commissioned. This will add to natural gas generation by almost a third (Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-QLD 55).

3.3.1.2. Ownership interests

Table 3.6 provides a summary of the generators operating in Queensland and the capacity controlled by those generators as at 1 January 2008. As can be seen from this table over 60 per cent of total electricity generation in Queensland is owned and operated by state-owned entities. The remaining 40 per cent is owned and operated by the Singapore based Intergen, Rio Tinto/Transfield Services, Babcock & Brown Power, Origin Energy and Oakey Power Holdings.[55]

Table 3.6 Queensland generation capacity by owner as at 1 January 2008

Operating company	**Capacity (GW)**	**Capacity (%)**
Queensland government	7.6	61.3
- CS Energy	*3.6*	*28.8*
- Tarong Energy	*2.4*	*19.1*
- Stanwell Corporation	*1.6*	*12.9*
- Enertrade[56]	*0.1*	*0.5*
- Ergon Energy	*0.0*	*0.1*
Rio Tinto/Transfield Services[57]	1.7	13.7
Intergen Australia[58]	0.9	6.9
Babcock & Brown[59]	0.5	3.9
Transfield Services[60]	0.4	3.4
Origin Energy[61]	0.4	3.4
Oakey Power Holdings[62]	0.3	2.3
Other interests[63]	0.6	5.1
Total capacity	**12.4**	**100**

Source: Electricity Gas Australia (2007), ESAA

55 These are either mining operations which own some of their own generation or plants built to use the bagasse by-product of sugar milling.

56 The Queensland government has abolished Enertrade and its assets have been transferred to other government-owned entities. The Gladstone power station agreement has been transferred to the Stanwell Corporation, CS Energy will take over the Collinsville power station agreement and Barcaldine power station will be transferred to Ergon energy. The West Australian, http://www.thewest.com.au/aapstory.aspx?StoryName=382178.

57 Gladstone coal station (1680MW) is owned by a consortium including Rio Tinto, Transfield Services and a group of aluminium traders (Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-QLD 2).

58 Millmerran coal station (852MW) is owned by Intergen Australia.

59 The Braemar gas plant mentioned above is Babcock & Brown's main asset in Queensland, but it also owns the 30MW Rocky Point biomass plant.

60 Transfield owns two natural gas plants at Collinsville (180MW) and Yabulu (240MW).

61 Origin Energy owns the Roma (natural gas, 80MW) and Mt Stuart (oil products, 304MW) stations outright and shares ownership with the Bulwer Island CCGT plant (32MW) with ATCO Power.

62 Oakey Power Holdings is owned by Babcock & Brown, ERM Power and Origin Energy (through its New Zealand subsidiary Contact Energy).
Babcock & Brown Annual Report 2005, http://www.babcockbrown.com/media/21102/annual%20report.pdf
ERM Power website, http://ermpower.com.au/projects/newgen-oakey-power-station
Contact Energy Annual Report 2005, http://www.originenergy.com.au/investor/files/Fullfinancials2005Final.pdf

63 This category contains nearly 30 small generators, a majority of which are industry offshoots such as bagasse plants in sugar refineries.

Total energy supplied by Queensland generators into the NEM for the financial year ending 30 June 2006 was nearly 60 TWh, representing 28 per cent of total NEM electricity supply. In 2005/06 Queensland exported around 10 per cent of its total electricity supply to New South Wales. Table 3.7 provides a summary of the sources of electricity supplied into Queensland over 2004/05 and 2005/06 and illustrates the share of the market accounted for by these generators. According to the data contained in this table government-owned generators supplied over 70 per cent of dispatched energy in Queensland.

Table 3.7
Queensland electricity supply market share

Operating company	**2004/05 (%)**	**2005/06 (%)**
Queensland government	72.2	70.5
- Tarong Energy	*27.2*	*26.2*
- CS Energy	*26.4*	*25.6*
- Stanwell Corporation	*18.7*	*18.7*
Enertrade[64]	16.4	18.4
Intergen	11.1	10.9
Imports from NSW	0.2	0.1
NewGen Power	0.0	0.1
Origin Energy	0.1	0.0
Total[65]	**55,798 GWh**	**57,104 GWh**

Source: Electricity Gas Australia (2007), ESAA

The locations of the major generators and linking transmission lines are identified on the map in Figure 3.5 below. As this map demonstrates generation in Queensland is characterised by a larger number of smaller capacity generators with capacity for the largest fourteen generators ranging from 240 MW (Yabula) to 1680MW (Gladstone). The Gladstone power station is currently the largest generator in Queensland. This power station was purchased from the Queensland Government in 1994 by a joint venture comprising Rio Tinto Aluminium, three of its Japanese partners in Boyne Smelters Limited, and NRG, a US-based energy provider.[66] Approximately 50 per cent of its electricity is provided to Boyne Smelters, which operates Australia's largest aluminium smelter in Gladstone.[67,68]

64 The enertrade component includes the electrical supply from the Gladstone power plant (owned jointly by Rio Tinto and Transfield Services).

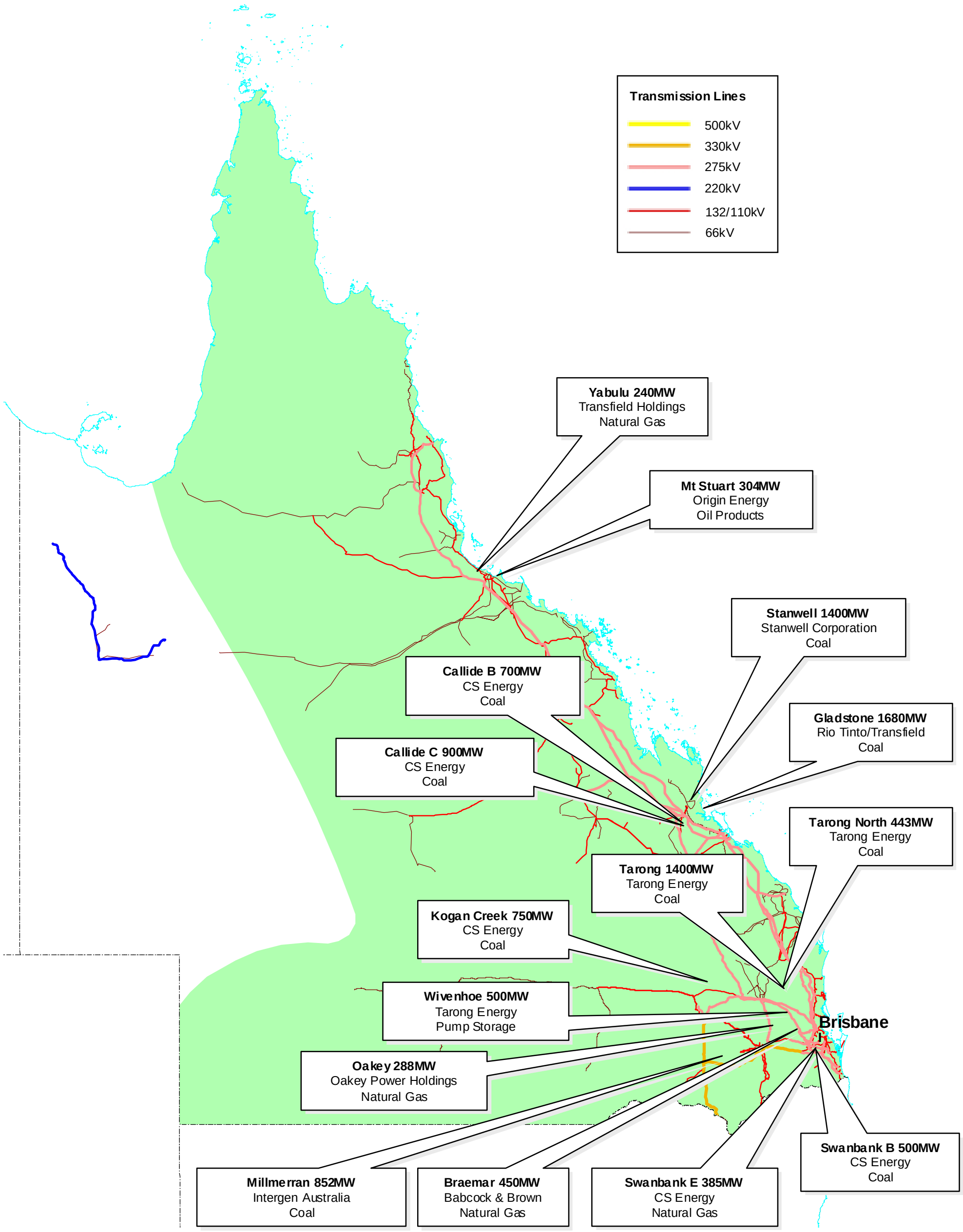
65 Note that Babcock & Brown's Braemar plant was commissioned after the end of the 05/06 year and hence is not reflected in these figures.

66 Comalco website, http://www.comalco.com/freedom.aspx?pid=408.

67 Ibid.

68 Comalco website, http://www.riotintoaluminium.com/freedom.aspx?pid=224.

Figure 3.6
Location of major generation in Queensland



Source: RLMS, annotated by NERA.

3.3.2. Transmission and distribution

The Queensland high voltage transmission network is owned and operated by Powerlink, which is state-owned.[69] The distribution network in Queensland is owned and operated by Energex and Ergon, both of which are state-owned corporations. Energex's distribution network services the major population areas of Brisbane, the Gold Coast and the Sunshine Coast, spanning 25,000 square kilometres.[70] Ergon is responsible for the distribution network in the remaining areas of regional Queensland. This large area encompasses over 1 million square kilometres with over 140,000 kilometres of powerlines.[71]

In 2008 a new 1,100 km transmission line was proposed which would connect Mt Isa's mining hub with the NEM. The project is estimated to cost $800 million and will be constructed by the Hong Kong-based Cheung Kong Group, majority owners of the distribution businesses, Powercor Australia, CitiPower and ETSA utilities.

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69 Powerlink website, http://www.powerlink.com.au/asp/index.asp?sid=5056&page=network/network

70 Energex website, http://www.energex.com.au/about_energex/our_network.html

71 Ergon website, http://www.ergon.com.au/Network_Info/

3.4. South Australia

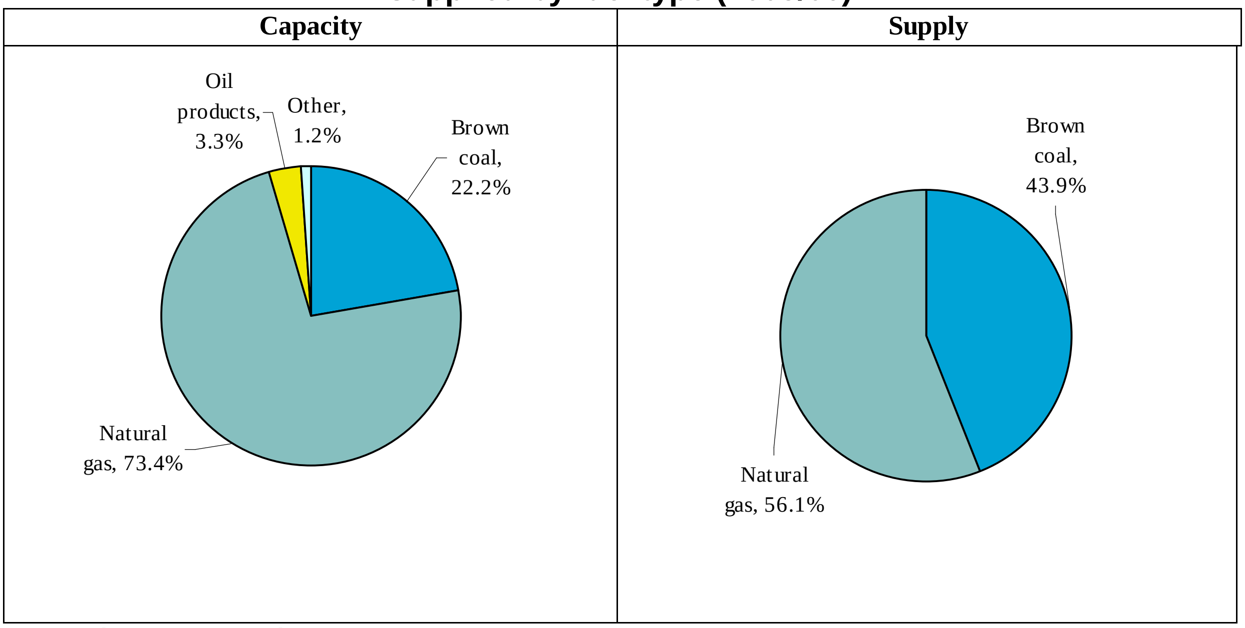
As at 1 January 2008 total generation capacity in South Australia was 4 GW, which represents 9 per cent of NEM capacity.

3.4.1.1. Fuel type

According to data published by the ESAA over 73 per cent of total capacity in South Australia was accounted for by natural gas and 22 per cent by brown coal over 2005/06. South Australia also currently has the largest supply of wind capacity in the NEM with approximately 388MW of capacity located at Lake Bonney, Canuda, Wattle Point, Starfish Hill, Mt Millar and Cathedral Rocks.[72]

While natural gas fired capacity accounts for 73 per cent of total capacity of scheduled generators in South Australia, these plants only supplied 56 per cent of electricity over 2005/06. Coal fired plants on the other hand fuelled almost half of base load generation notwithstanding the fact that it only accounted for 22 per cent of scheduled generation capacity.

Figure 3.7: South Australia scheduled generation capacity and electricity supplied by fuel type (2005/06)



Source: Electricity Gas Australia (2007), ESAA

3.4.1.2. Ownership interests

Table 3.8 provides a summary of the generation companies operating in South Australia. As this table indicates scheduled generation capacity in South Australia is provided entirely by privately owned companies with the four major generation companies being AGL,

72 Controlled by Babcock & Brown and Prime Infrastructure, International Power, AGL, the Queensland government through Tarong Energy (both Starfish Hill and Mt Millar) and Roaring 40s (a joint venture between Hydro Tasmania and China Light and Power), respectively (Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-SA 22, 24-26, Roaring 40s website, http://www.roaring40s.com.au/ourprojects.html).

International Power, Flinders Power and TRUenergy. These four generators accounted for 80 per cent of South Australia's 4.0 GW of capacity as at 1 January 2008. The remaining generation capacity is owned by ATCO Power, and Origin Energy.

Table 3.8
South Australia generation capacity by owner as at 1 January 2008

Owner	Capacity (GW)	Capacity (%)
AGL[73]	1.4	34.2%
International Power Australia[74]	0.9	22.1%
Flinders Power[75]	0.8	19.2%
TRUenergy[76]	0.2	4.6%
ATCO Power and Origin Energy[77]	0.2	4.6%
Origin Energy[78]	0.2	4.4%
Other interests[79]	0.4	10.9%
Total capacity	**4.0**	**100**

Source: Electricity Gas Australia (2007), ESAA and other sources as footnoted.

South Australian generators produced 10.7 TWh of electricity in 2005/06, which represented approximately 5 per cent of the total electricity supplied in the NEM. As can be seen from the table below South Australia relies heavily on imports from Victoria which is supplied through two interconnectors. Over 2005/06 imported electricity accounted for 20 per cent of South Australia's electricity consumption.[80]

73 AGL acquired the Torrens Island natural gas power station through an asset swap with TRUenergy in July 2007. AGL also owns the Wattle Point wind farm.

74 International Power owns the natural gas plant at Pelican Point (its largest station in South Australia at 478MW) and the Canuda Wind Farm. Additionally it has a long term lease over the four Synergen plants with a total of 359MW of capacity – the Mintaro and Dry Creek natural gas plants and two oil-product-fired stations at Snuggery and Port Lincoln. International Power website, http://www.ipplc.com.au/Page.php?iPageID=34

75 Two coal-fired stations, Northern (530MW) and Thomas Playford B (240MW).

76 TRUenergy acquired Hallett 180MW through an asset swap with AGL in July 2007.

77 ATCO and Origin each have a half share in the Osborne natural gas plant. Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-SA 12.

78 Origin owns the 84MW Ladbroke Grove and 92MW Quarantine natural gas plants.

79 This category includes a variety of small plants including Starfish Hill and Lake Bonney wind farms, oil product fired plants owned by Cummins (20MW at Lonsdale) and Infratil (40MW at Angaston) and a landfill gas plant owned by Energy Developments (16MW at Wingfield).

80 Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, page 7-7.

Table 3.9[81]
South Australia electricity supply market share

Operating company	2004/05 (%)	2005/06 (%)
Flinders Power	45.4	34.9
Imports from Vic	19.4	20.4
AGL	22.1	19.3
International Power Australia	8.5	12.5
ATCO Power and Origin Energy	0.0	9.0
Origin	4.4	3.7
TRUenergy	0.2	0.2
Total	**12,958 GWh**	**12,954 GWh**

Source: Electricity Gas Australia (2007), ESAA

Figure 3.8 illustrates the location of major generation in the region. The largest electricity generators in South Australia are AGL (Torrens Island gas fired plant (1280MW)),[82] International Power (the Pelican Point gas fired plant (478MW) and the four Synergen peaking plants), Flinders Power (Northern coal fired plant (530MW) and Thomas Playford B coal fired plant (240MW)) and TRUenergy (Hallett gas fired power plant (180MW)).

In addition to the above generation assets there are six wind farm projects in South Australia. These wind farms are located at Wattle Point (90MW) owned by AGL, Lake Bonnet (81MW) owned by Global Wind Partner, Mount Millar (70MW) and Starfish Hill (35MW) both of which are owned by Tarong Energy[83], Cathedral Rocks owned by Roaring 40's[84] and the Canuda Wind Farm located at Lake Bonney which is owned by International Power.

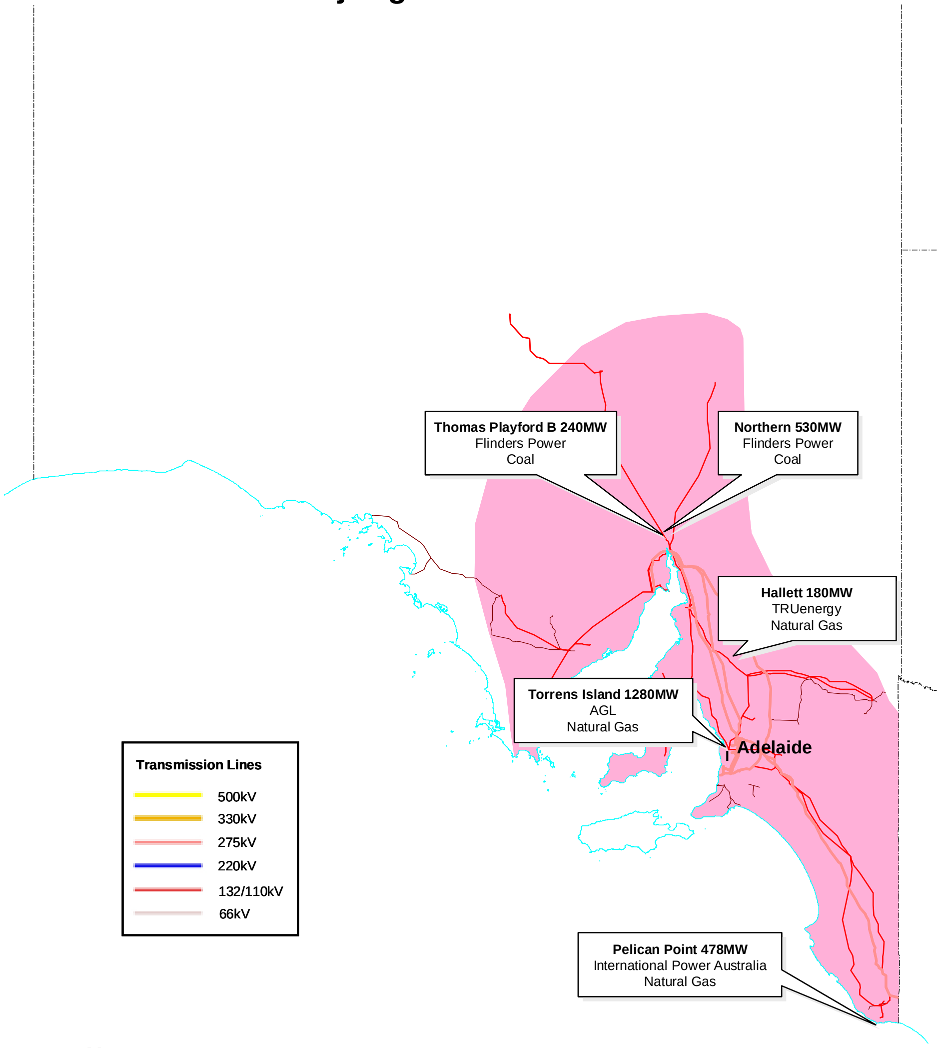
81 The AGL – TRUenergy asset swap was completed in 2007 and therefore the effects of the transaction are not reflected in table 3.9 which refers to the 2004/05 and 2005/06 financial years.

82 AGL acquired the Torrens Island Power Plant through an a asset swap with TRUenergy. This asset swap resulted in the transfer of Torrens Island Power Plant from TRUenergy to AGL and the transfer of Hallett Power Station from AGL to TRUenergy. This exchange also resulted in the transfer of gas sales and haulage agreements. See http://www.agl.com.au/AGL/Press+Releases/AGL+acquires+further+1,280MW+of+clean-burn,+gas-fired+generation.htm

83 Tarong Energy is a Queensland Government Corporation.

84 Roaring 40's is a joint venture between Hyrdo Tasmania and China Light and Power. Roaring 40s website, http://www.roaring40s.com.au/ourprojects.html).

Figure 3.8
Location of major generation in South Australia



Source: RLMS, annotated by NERA.

As the map demonstrates the Pelican Point gas-fired station is located at one end of the SEA Gas pipeline while the Torrens Island Power Station is located at the other end of the pipeline. The gas used by these two generators is supplied from the Otway Basin.[85] The two brown coal-fired stations are located near their associated mine at Leigh Creek, approximately 250 kilometres north of Port Augusta.[86] The Hallett power station is supplied with gas from the Cooper Basin which is transported via the Moomba to Adelaide Pipeline System.

3.4.2. Transmission and distribution

The electricity transmission network in South Australia is owned and operated by ElectraNet, which is owned by Harold Street Holdings, YTL Power Investments, Hastings Funds Management and Macquarie Specialist Asset Management.[87] It is responsible for delivering

85 Hughes, Tim, "SEA Gas Pipeline Rolls Out", MESA journal 28, January 2003.

86 Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-SA 2 and 4.

87 ElectraNet Annual Review 2006, p.9, http://www.electranet.com.au/images/pdfs/annualreview2005.pdf

electricity via 6,000 kilometres of transmission lines throughout South Australia, a widely dispersed area that is comparable in size to Western Europe.[88]

The distribution network is provided by ETSA Utilities, which is owned by Cheung Kong Infrastructure, HK Electric Holdings and Spark Infrastructure.[89] The main distribution network is centred in Adelaide, which is the primary load centre in South Australia.

88 ElectraNet website, http://www.electranet.com.au/company.html

89 Electricity Gas Australia (2006), ESAA.

3.5. Snowy

In accordance with a final rule determination made by the AEMC the Snowy region will be abolished by 1 July 2008. At this time the Tumut generator will become part of the New South Wales region while the Murray generator will become part of the Victoria region.[90]

As at 1 January 2008 total generation capacity in the Snowy Region was 3.7 GW, which represents 8 per cent of NEM capacity.[91]

3.5.1.1. Fuel type

The Snowy region's generation capacity consists of seven hydro generation plants including Tumut 1 (330 MW), Tumut 2 (286 MW), Tumut 3 (1500 MW), Murray 1 (950 MW), Murray 2 (550 MW), Blowering (80 MW) and Guthega (60 MW).[92][93]

3.5.1.2. Ownership interest

These generators are owned and operated by Snowy Hydro, which is itself owned by the New South Wales, Victorian and Commonwealth governments. The Snowy Scheme accounts for approximately 74 per cent of all renewable energy dispatched into the NEM each year.[94]

In the financial year ending June 2006, Snowy Hydro's generators supplied 5,166 GWh of electricity into the NEM.[95] This was almost entirely exported through the interconnectors, with approximately 66 per cent being exported to New South Wales and 30 per cent to Victoria.[96]

Figure 3.9 identifies the location of the main generation plants in the Snowy region.

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90 AEMC website, http://www.aemc.gov.au/media.php?article=4

91 Electricity Gas Australia (2007), ESAA.

92 Ibid.

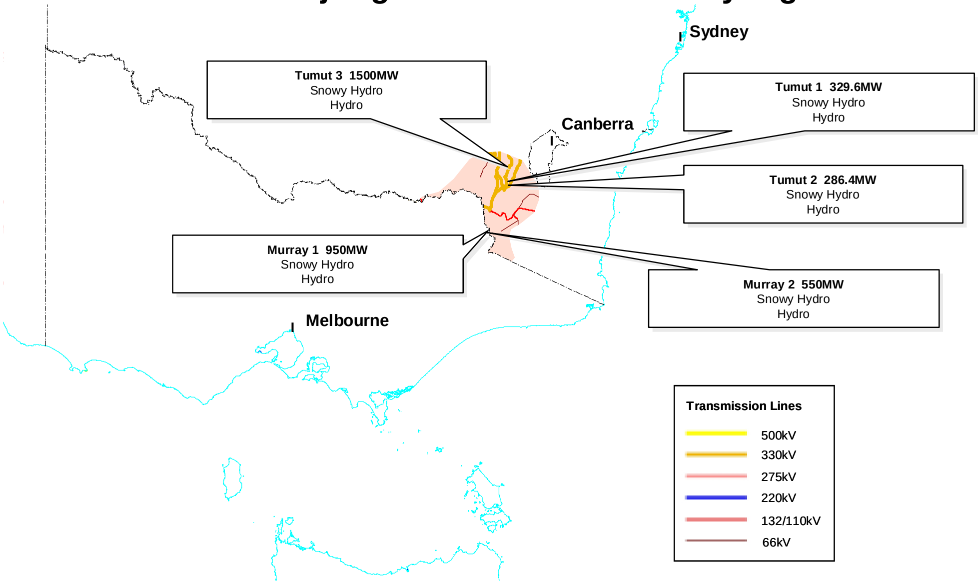
93 The Snowy Hydro scheme was built over 25 years, beginning in 1949 and produces hydro power through a complicated network which consists of sixteen major dams, 145 kilometres of interconnected tunnels and 80 kilometres of aqueducts.

94 Snowy Hydro, http://www.snowyhydro.com.au/levelTwo.asp?pageID=289&parentID=3

95 Source: Electricity Gas Australia (2007), ESAA.

96 Source: Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, page 7-7.

Figure 3.9
Location of major generation in the Snowy region



Source: RLMS, annotated by NERA.

3.6. Tasmania

3.6.1. Generation

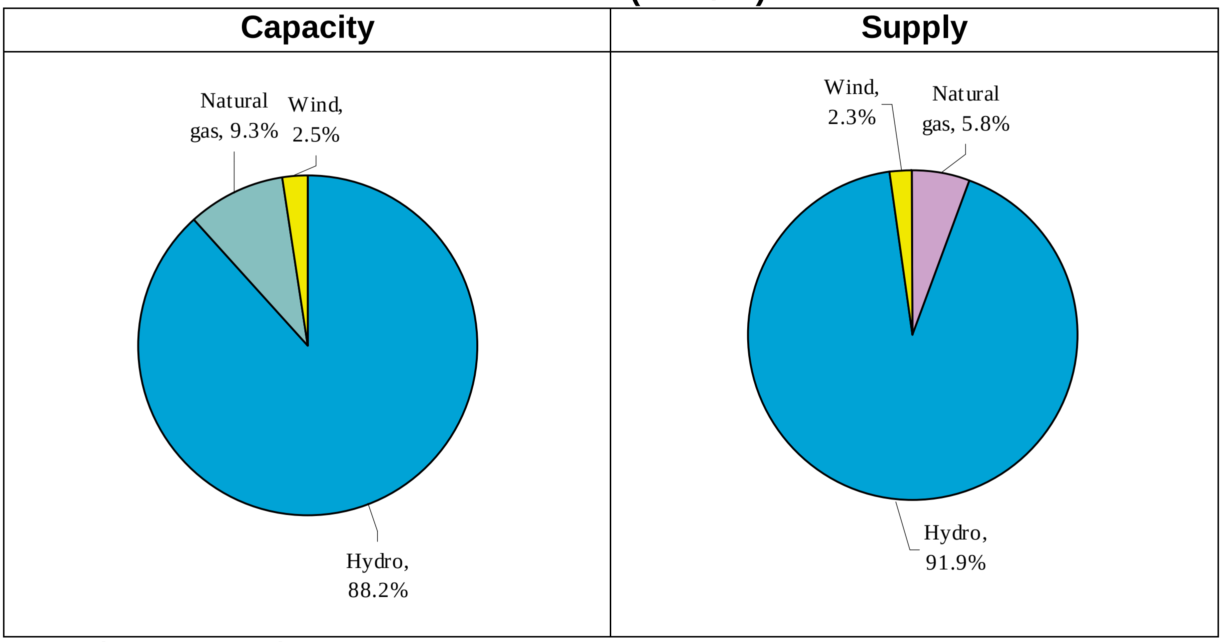
Tasmania joined the NEM on 29 May 2005 in anticipation of the completion of the Basslink interconnector. The Basslink interconnector was designed to enable electricity to be transferred between Tasmania and the mainland.[97]

As at 1 January 2008 total generation capacity in Tasmania was 2.7 GW which represents 6 per cent of NEM capacity.

3.6.1.1. Fuel type

According to data published by the ESAA hydro generation accounted for 88 per cent of Tasmania's capacity while natural gas accounted for just over 9 per cent[98] and wind 2.5 per cent over 2005/06. [99] Of the electricity supplied by Tasmanian generators over 2005/06, approximately 92 per cent was sourced from hydro generators with the remainder sourced from a combination of wind and natural gas. The difference between capacity and electricity supplied can be seen in the figure below.

Figure 3.10: Generation capacity and electricity supplied by fuel type, Tasmania (2005/06)



Source: Electricity Gas Australia (2007), ESAA

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97 Hydro Tasmania website, http://www.hydro.com.au/home/Energy/NEM+and+Basslink/The+National+Electricity+Market.htm

98 Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-TAS 36.

99 Natural gas for the Bell Bay turbines is supplied from Victoria via the Tasmanian Gas Pipeline This also includes the 108 MW Bell Bay gas fired generator which was commissioned in August 2006. Electricity Gas Australia (2007), ESAA.

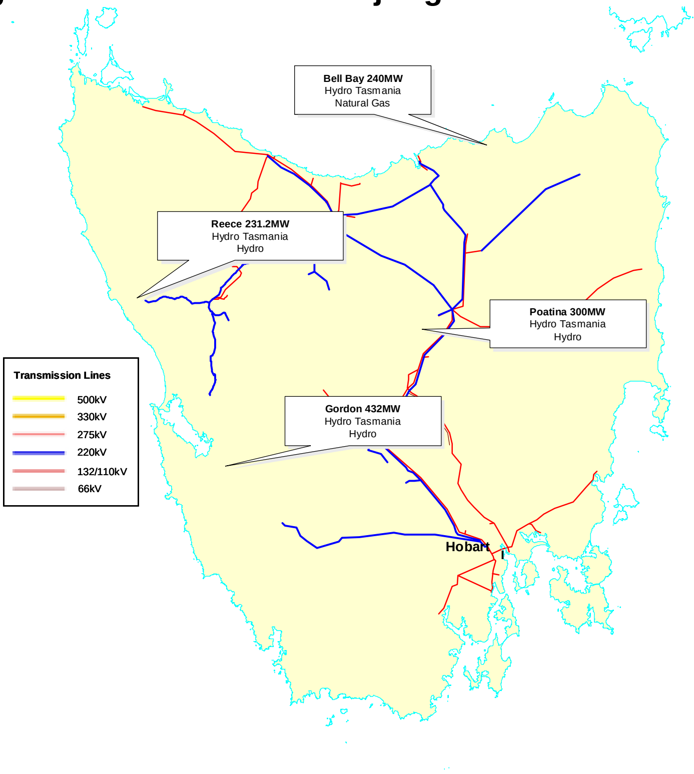
3.6.1.2. Ownership interests

Electricity in Tasmania is provided almost entirely by Hydro Tasmania, which is owned by the Tasmanian Government. Hydro Tasmania operates thirty one hydro generators, a wind farm and a natural gas plant, [100] supplying 10.5 TWh of electricity in 2005/06. This represented 5 per cent of total NEM electricity supply. The Bell Bay natural gas plant is expected to be decommissioned in 2009 and will be replaced with a 210MW CCGT fired plant with additional peaking capacity of 180 MW.[101]

Tasmania's hydro generators are principally located in an integrated scheme in high rainfall areas, consisting of numerous lakes and over 50 large dams.[102] The predominance of hydro generation in Tasmania means that it has the largest portion of renewable energy in the NEM, excluding the special case of Snowy. In addition, Hydro Tasmania has interests in wind generation through its joint venture with China Light and Power, Roaring 40s, represented in Tasmania by the 64.5MW Woolnorth farm.

The location of Hydro Tasmania's major generators is identified in Figure 3.11 below.

Figure 3.11: Location of major generation in Tasmania



Source: RLMS, annotated by NERA.

100 The Bell Bay Three represents three turbines added to the existing Bell Bay plant; for practical purposes they comprise one plant.
Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-TAS 38. This station was sold to Alinta in Une 2007 however Hydro Tasmania continue to operate the plant.

101 Alinta website, http://www.alinta.net.au/operations/generation/TamarValleyPowerStation/default.aspx.

102 Hydro generation in Tasmania has a long history, with the oldest plant, Tarraleah, having been commissioned in 1938 see Hydro Tasmania website, http://www.hydro.com.au/home/Corporate/Generating_Power/

3.6.2. Transmission and distribution

The electricity transmission network in Tasmania is operated by Transend, a state-owned corporation that operates a network of 3,500 kilometres of transmission lines.[103] Aurora Energy is the distribution network service provider in Tasmania and is also state-owned. It provides distribution services to approximately 260,000 customers throughout Tasmania.[104]

The integration of Tasmania into the NEM has been achieved through the construction of the Basslink interconnector, connecting Tasmania with Victoria. The Basslink interconnector is a DC interconnector, with a capacity of 600MW into Victoria and 300MW from Victoria and has been in operation since April 2006.[105] The available flow data does not conclusively suggest whether Tasmania will tend to be a net importer or exporter of electricity although it was a small net exporter of 19 GWh for the period April-June 2006.[106]

In July 2007 the Basslink interconnector was sold by National Grid to the Singaporean infrastructure trust CitySpring Infrastructure Management for $1.2 billion.

103 Transend website, http://www.transend.com.au/

104 Aurora Energy Annual Report 2006, http://www.auroraenergy.com.au/pdf/about_aurora/annual_report_0506/year_in_review.pdf

105 Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. 7-7.

106 Ibid.

3.7. Victoria

3.7.1. Generation

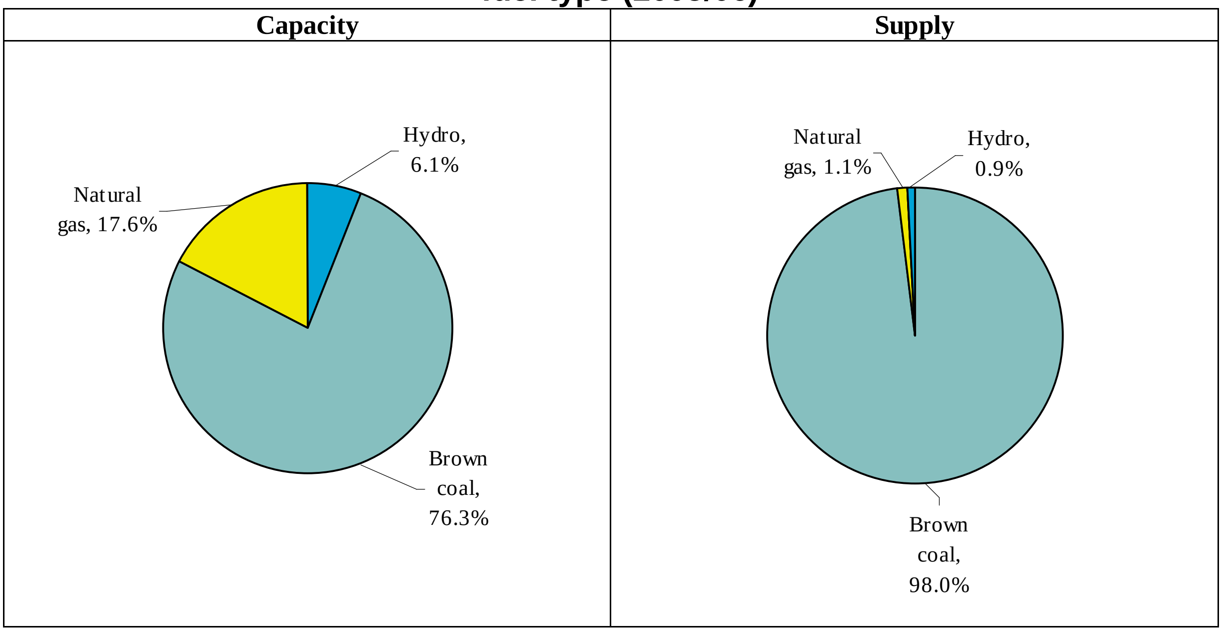
As at 1 January 2008 total generation capacity in Victoria was 9.4 GW which represents 21 per cent of NEM capacity.

3.7.1.1. Fuel type

According to data published by the ESAA over 76 per cent of Victoria's capacity was supplied by coal-fired power generators located in the Latrobe Valley over 2005/06.[107] Natural gas is the second largest fuel source in Victoria, accounting for 18 per cent of total Victorian generation capacity. Hydro electricity accounts for approximately 6 per cent of Victoria's capacity, and 133 MW (or 1.4 per cent) of total capacity is provided by five wind farms located at Ararat, Codrington, Yambuck, Toora and Wonthaggi.

Similar to other states the proportion of capacity accounted for by brown coal is lower than the proportion of actual energy supplied by this fuel type (76 per cent vs 98 per cent) and the proportion of actual energy supplied by natural gas is lower than its share of total capacity (18 per cent vs 1 per cent). The charts below illustrate this difference.

Figure 3.12: Victoria scheduled Generation capacity and electricity supplied by fuel type (2005/06)



Source: Electricity Gas Australia (2007), ESAA

3.7.1.2. Ownership interests

Table 3.10 provides a summary of the generators operating in Victoria and the capacity controlled by those generators as at 1 January 2008.

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107 Victoria Department of Primary Industries, Mineral Notes: Brown Coal, updated April 2007.

Table 3.10
Victoria generation capacity by owner as at 1 January 2008

Operating company	Capacity (GW)	Capacity (%)
Loy Yang Power[108]	2.1	22.5%
Hazelwood Power Partnership[109]	1.6	17.0%
TRUenergy[110]	1.5	15.7%
IPM Eagle[111]	1.0	10.6%
Ecogen Energy[112]	1.0	10.2%
AGL[113]	0.7	7.4%
Snowy Hydro[114]	0.6	6.6%
Energy Brix[115]	0.2	2.1%
Alcoa[116]	0.2	1.7%
Alinta[117]	0.1	1.0%
Eraring Energy[118]	0.0	0.3%
Pacific Hydro	0.1	1.1%
Other interests[119]	0.4	3.9%
Total capacity	**9.4**	**100**

Source: Electricity Gas Australia (2007), ESAA and other sources as footnoted.

As this table demonstrates Victoria is characterised by a relatively large number of private generation companies with five companies each controlling over 10 per cent of total generation capacity in Victoria and producing in excess of 49 TWh of electricity in 2005/06 (or 23 per cent of total NEM electricity supplied in 2005/06). International Power and its consortium partners in Hazelwood and Loy Yang B (IPM Eagle) accounted for the largest proportion of capacity in 2005/06 followed by the Great Energy Alliance Corporation consortium through its interest in Loy Yang A. TRUenergy's 1480MW Yallourn W plant,

108 Loy Yang Power, which owns the 2120MW Loy Yang A coal power station, is owned by the Great Energy Alliance Corporation (GEAC): AGL, Tokyo Electric and an investor group led by Commonwealth Bank.

109 International Power and the Commonwealth Bank Group own the Hazelwood Power Partnership which owns the 1600MW Hazelwood coal station.

110 Yallourn W 1480MW coal-fired plant.

111 International Power and Mitsui own the 1000MW Loy Yang B coal plant through IPM Eagle.

112 Babcock & Brown has a majority stake in the 510MW Newport and 449MW Jeeralang (A and B) natural gas power stations through Ecogen.

113 AGL owns six hydro stations in Victoria (two at 150MW, one 120MW, one 62MW, one 29MW and one 12.2MW) and a 150MW natural gas plant at Somerton.

114 Snowy Hydro owns the 300MW Valley Power natural gas plant and the 340MW Laverton North natural gas plant. Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-VIC 29.

115 Energy Brix, owned by HRL Limited Group, is a 195MW cogeneration plant which uses waste heat from its boiler to dry brown coal into briquettes for industry.
Energy Brix website, http://www.ebac.com.au/brix/services.asp

116 Alcoa has a 160MW coal plant at Anglesea.

117 Alinta owns the 92MW Bairnsdale natural gas plant.

118 NSW government-owned Eraring Energy owns a 29MW hydro station at the Hume Weir.

119 Queensland government-owned entities Energy Impact and Stanwell Corporation own the 12.42MW natural gas turbine at Royal Melbourne Hospital and the 21MW wind farm at Toora, respectively. The majority of the rest of this capacity is provided by industry offshoot plants such as those at Amcor Paper and Paperlinx.
Energex Annual Report 2005, http://www.energex.com.au/pdf/about_energex/annualreportpdfs05/corporate_reports.pdf

Babcock & Brown's Jeeralang and Newport plants and AGL's several smaller plants give each of these entities sizeable portions of total capacity in Victoria.

Table 3.11 provides a summary of the sources of electricity supplied into Victoria over 2004/05 and 2005/06.

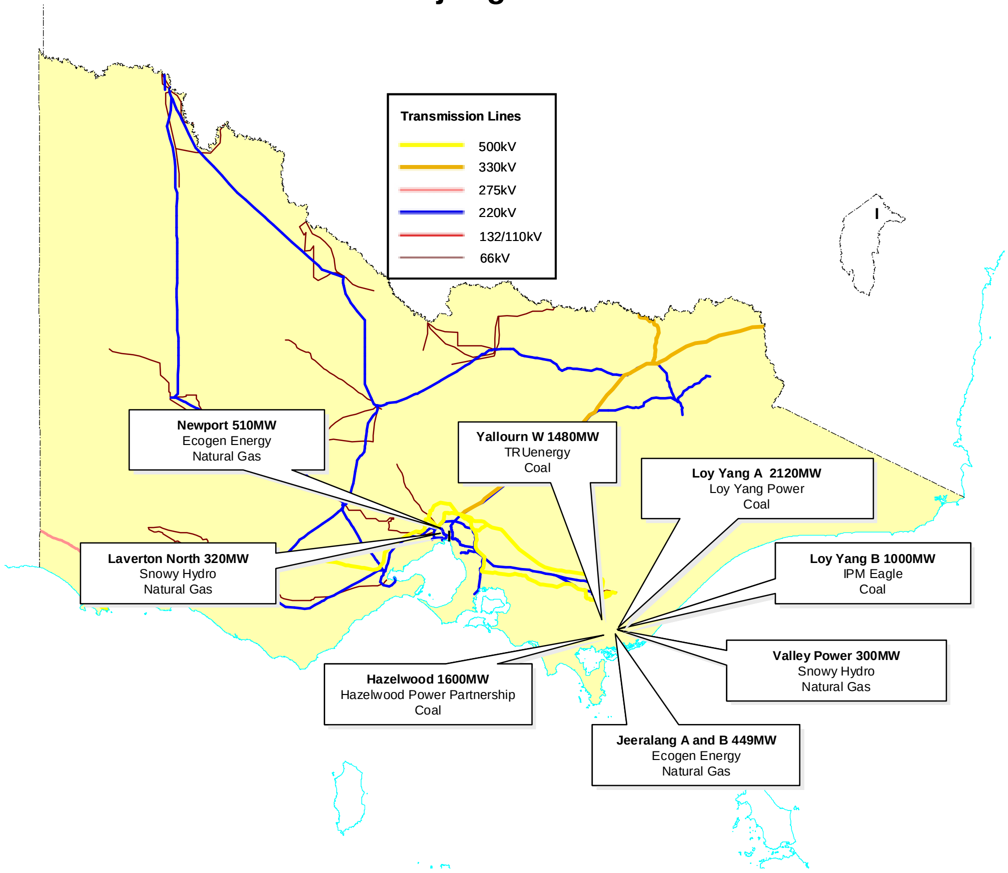
Table 3.11
Victoria electricity supply market share

Operating company	2004/05 (%)	2005/06 (%)
Loy Yang Power	32.1	31.0
Hazelwood Power Partnership	21.1	20.5
TRUenergy	21.3	20.4
IPM Eagle	14.5	15.9
Imports from Snowy region	2.8	4.5
Alcoa	2.2	2.5
Energy Brix	2.1	1.9
Imports from NSW	0.4	0.9
Ecogen	2.0	0.9
AGL	1.1	0.8
Others	0.4	0.7
Total	**54,282 GWh**	**55,140 GWh**

Source: Electricity Gas Australia (2007), ESAA

Figure 3.13 identifies the location of all generation capacity in excess of 200MW in the Victorian NEM region. These eight generators account for 82 per cent of total generation capacity located in Victoria. The four largest generation plants represent 66 per cent of total capacity and facilities range in size from 2120MW (Loy Yang A) to 1000MW (Loy Yang B).

Figure 3.13
Location of major generation in Victoria



Source: RLMS, annotated by NERA.

3.7.2. Transmission and distribution

Transmission services in Victoria are provided by three companies, the Victorian Energy Networks Corporation (VENCorp), SP AusNet and SPI PowerNet. VENCorp is a state-owned corporation and does not own any of the assets that its services cover. Its responsibilities include providing network services and planning and directing the augmentation of the network.

SPI PowerNet owns, operates and maintains a network of over 6,500 kilometres of transmission lines that stretches through 228,000 kilometres of Victoria.[120] The remaining 6,574 kilometre transmission network is owned by SP AusNet.[121]

Electricity distribution services are provided by a number of different companies. Citipower owns and manages a network area of 157 square kilometres in the Melbourne central business district and inner suburbs.[122] Powercor has a larger distribution area that provides services

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120 AER, Victorian transmission network revenue caps: Decision, 11 December 2002, p.6.

121 SP AusNet, Electricity Transmission Revenue Proposal, 31 March 2007, p.2.

122 Citipower website, http://www.citipower.com.au/

across 65 per cent of Victoria.[123] However, both entities are owned by the same group of companies.[124]

United Energy Distribution services the south-east of Melbourne and the Mornington Peninsula with 12,600 kilometres of lines over approximately 1,450 square kilometres of land.[125,126] SP AusNet also provides distribution services. Their network stretches across more than 80,000 square kilometres in eastern Victoria.[127]

In the north west of greater Melbourne Alinta provides electricity distribution services, though until late 2006 the network was owned by AGL. Approximately 285,000 homes and businesses receive electricity through a network of approximately 10,285 kilometres of lines.[128]

Victoria is connected to the surrounding NEM regions via four interconnectors. In the 2006 financial year, Victoria was a net exporter of electricity to South Australia and a net importer from the Snowy region, resulting in a net export of approximately 1.4 per cent of Victoria's supplied energy.

3.8. Proposed investments

3.8.1. Generation

ABARE provides an indication of proposed generator investments for each of the NEM regions.[129] These indicate that over 13 GW of generation capacity is currently proposed in the NEM leading up to the period 2013. This represents an additional 33 per cent increase in capacity compared with current operating generator capacity.

Significant developments expected to be completed in the near future include an upgrade to the Mt Piper coal power station by Delta Electricity (1680 MW) and construction of the Mortlake CCGT power station in Victoria and the Spring Gully CCGT power station in Queensland by Origin Energy (both 1000 MW).[130] TRUenergy's Tallawarra 400MW CCGT plant is expected to be operational in New South Wales in 2008.[131]

The most significant wind project under construction is the Pacific Hydro 195MW Portland Wind Project in Victoria, expected to be completed by 2008.[132] Macquarie Bank along with

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123 Powercor website, Australia http://www.powercor.com.au/infocentre/fs_electricity.html

124 Energy Gas Australia (2006), ESAA.

125 United Energy, ASX Release, "United Energy Obtains Court Approval of Scheme of Arrangement", 15 July 2003.

126 United Energy Distribution website, http://www.ue.com.au/industry/distributionMap.htm.

127 SP AusNet website, http://www.sp-ausnet.com.au/CA256FE40020993B/page/Distribution?OpenDocument&1=100-Distribution~&2=~&3=~

128 Alinta website, http://www.alinta.net.au/operations/distribution/alintaVICElecNetworks/

129 ABARE (2006), Energy in Australia 2006, p. 53 to 54.

130 Ibid.

131 Australian Electricity Market Study 2020 Outlook (2007), Core Collaborative, p. A-NSW 26.

132 Pacific Hydro, http://www.pacifichydro.com.au/Default.aspx?tabid=134.

the renewable energy company Epuron have also announced plans to build Australia's largest Wind Project near Broken Hill. The project is estimated to cost $2 billion with the wind farm expected to have a capacity of 1,000MW (this capacity has not been included in the table below as the project is still in the early planning stage).

The table below provides a summary of the additional capacity that is likely to flow from the current proposals over 2008-2012.

Table 3.12: Proposed new generations plants 2008-2012

Region	Capacity (MW)
New South Wales	6,320
Queensland	3,517
South Australia	528
Tasmania	329
Victoria	2,416
Total	**13,110**

Source: ABARE, Energy in Australia 2008, pp. 48-50.

3.8.2. Interconnectors

In addition to new generation investments, there are a number of planned interconnector projects for the NEM. These projects have the purpose of either linking new areas to the NEM or expanding the existing capacity of the NEM. These are listed in the table below.

Table 3.13
Major Interconnector Projects

Interconnector Path	Project Type	Forward MW	Reverse MW	Status	Timeframe / Startup
Central to North Queensland	Augmentation	290	0	Committed	4 years
South-west to south-east Queensland	Augmentation	700	0	Committed	1 year
South-west to south-east Queensland	Augmentation	400	0	Committed	3-4 years
South-west to south-east Queensland	New double circuit line	1000	0	Potential	5 years
Northern South Australia to Adelaide	Augmentation	1100	0	Committed	2 years
Queensland's north west minerals province to central Queensland	New high voltage direct current transmission line	Not yet release	n.a.	Proposed	n.a.

Source: ABARE, Energy in Australia 2008, pg. 42.

4. Electricity retail in the NEM

4.1. Overview of operation of the retail market

Electricity retailers in the NEM acquire electricity from the wholesale market and provide for the supply of this to end-use customers that are not participants in the NEM.

Reforms over the past fifteen years have had a substantial impact on electricity retailing in the NEM. These reforms have included:

§ the vertical separation of retail functions from generation (although some re-integration has occurred in Victoria and South Australia) and in some states, the vertical separation of retailers from network service providers; and

§ the introduction of retail competition, whereby electricity consumers are able to choose their electricity supplier.

The various NEM jurisdictions have introduced full retail contestability (FRC) in a phased approach with large users being the first to have the opportunity to choose their provider, followed by progressively smaller customers over time (see table below).

Table 4.1: Summary of retail competition introductions

	Jurisdiction					
Customer Type	**ACT**	**NSW**[1]	**Qld**	**SA**[1]	**Tas**	**Vic**[2]
By demand:						
> 5 MW						Dec-94
> 1 MW						Jul-95
By energy:						
> 40 GWh		Oct-96	Mar-98			
> 20 GWh					Jul-06	
> 4 GWh			Oct-98		Jul-07	
> 750 MWh					Jul-08	Jul-96
> 200 MWh			Jul-99			
> 160 MWh	Jun-98			Jan-00		Jul-98
> 150 MWh					Jul-09	
> 100 MWh	Jul-01		Jul-04			
> 40 MWh		Jul-01				Jan-01
all customers	Jul-03	Jan-02	Jul-07	Jan-03	Jul-10[3]	Jan-02

Notes:
1. Some data is missing.
2 Between July 1996 and December 2001, all customers with maximum demand greater than 1 MW were contestable regardless of their total energy usage.
3. This is subject to a public benefits test.
Sources: Various regulator websites

Despite most jurisdictions in the NEM having implemented full retail competition, most jurisdictions still provide regulated tariffs and/or price oversight for small customers while the market is in transition to greater competition.[133] Currently, there are similar provisions in place for smaller customers, for example:

- ESCOSA regulates a standing contract (price, terms and conditions) that the incumbent, AGL, must offer customers consuming below 160MWh a year;[134]
- IPART also regulates the prices for small consumers of less than 160 MWh per year offered by the three incumbent providers, Country Energy, EnergyAustralia and Integral Energy;[135] and
- ESC has reserve powers to regulate prices of electricity for those consuming less than 160 MWh per year.[136]

Under new principles established by a COAG agreement, announced 10 February 2006, states are to phase out all forms of energy retail price regulation where effective competition is in place.[137] The AEMC's reviews of the effectiveness of retail gas and electricity competition will inform this decision.

4.2. Relationship between retailer cost structures and market structure

The principal costs incurred by retailers are associated with:

- purchasing electricity from the wholesale market;
- network fees relating to the transport of electricity to end-use customers;
- jurisdictional licensing fees and NEMMCO participant fees; and
- operating costs, such as those for customer support systems, marketing, etc.

The cost associated with purchasing electricity from the wholesale market includes the risk premium required by retailers to hedge against adverse movements in electricity prices. Typically such hedging will be achieved by contracting directly with generators or through an intermediary (see section 5 for a discussion of the instruments used in these transactions. The purchasing costs incurred by a retailer also include energy losses sustained in transport to end-use customers).

Several government initiatives targeted at the reduction of greenhouse gas emissions have an effect on the energy costs faced by a retailer. For example:

- Queensland has a 13 per cent Gas Scheme, whereby electricity retailers must source at least 13 per cent of their electricity from gas fired generation including either natural, coal seam methane, LPG or waste gas and accredited generators create credits that retailers

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133 NCC, Assessment of governments' progress in implementing the National Competition Policy and related reforms: 2005, October 2005, p.6.4.

134 ESCOSA website, http://www.escosa.sa.gov.au/site/page.cfm?u=172

135 IPART website, http://www.ipart.nsw.gov.au/investigations.asp?industry=2&sector=3

136 ESC website, http://www.esc.vic.gov.au/public/Energy/

137 COAG website, http://www.coag.gov.au/meetings/100206/index.htm

must be able to surrender as proof of 13 per cent electricity sold or used in the state consistent with the scheme;[138] and

- The New South Wales Greenhouse Plan for retailers is to offer all new or moving residential customers a ten per cent Green Power component.[139]

A number of benchmarking studies have been undertaken to analyse the breakdown of these costs. Charles River Associates (CRA) undertook a benchmarking study for the Queensland Competition Authority and found that network and energy costs account for approximately 92 per cent of the retail price of electricity. The remaining 8 per cent represents the retailers' operating costs and a margin.[140] In November 2007 the Chairman of IPART presented the following breakdown of retail electricity costs:[141]

- wholesale electricity costs – 40 per cent;
- network costs – 46 per cent;
- retail costs – 8 per cent; and
- the retail margin – 5 per cent.

A retailer considering whether or not to enter a particular jurisdiction would need to consider how to obtain a customer base that is sufficient to spread any fixed transmission and distribution charges, in addition to fixed business operating costs. However, with developments in outsourcing and information technology, new retailers are able to adopt more flexible business practices that can reduce the cost of entry and the associated customer base required.

The scale a retailer is able to attain will depend on the composition of demand in each jurisdiction and the number of customers in each jurisdiction. Figure 4.1 and Figure 4.2 illustrate the influence of these two factors.

Examining ABARE's 2006-07 final electricity consumption estimates it is immediately apparent that the consumption of electricity by end users varies significantly across the jurisdictions both in terms of the composition of users and the quantities of electricity consumed (see Figure 4.1). The number of residential customers in each state and territory in eastern Australia also varies markedly (see Figure 4.2).

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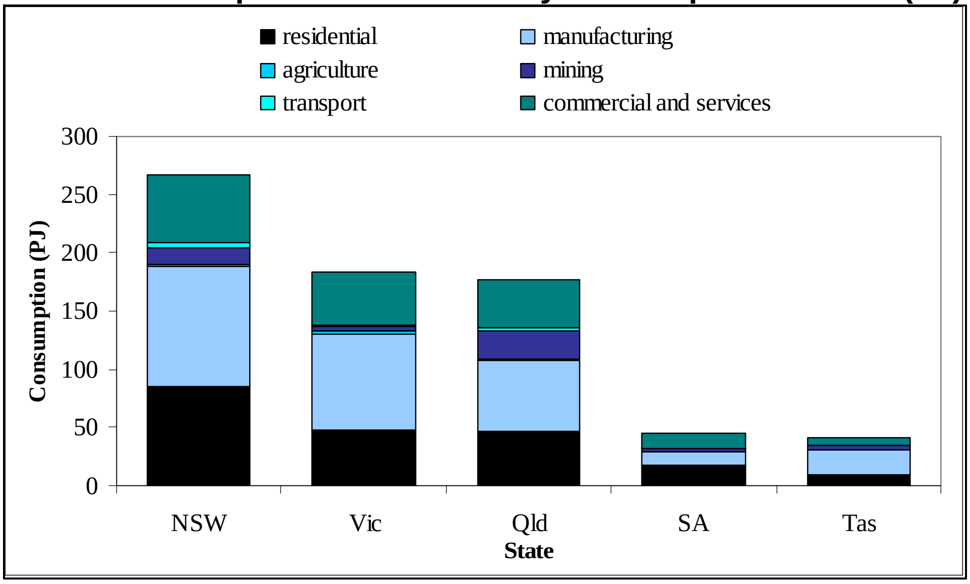
138 Queensland Department of Mines and Energy website, http://www.energy.qld.gov.au/13percentgas.cfm

139 IPART, Regulated Retail Tariffs and Charges for Small Customers 2007 to 2010: Draft Report and Determination, April 2007, p.15.

140 CRA, Calculation of the Benchmark Retail Cost Index for 2006-07 and 2007-08, 7 May 2007, p.3.

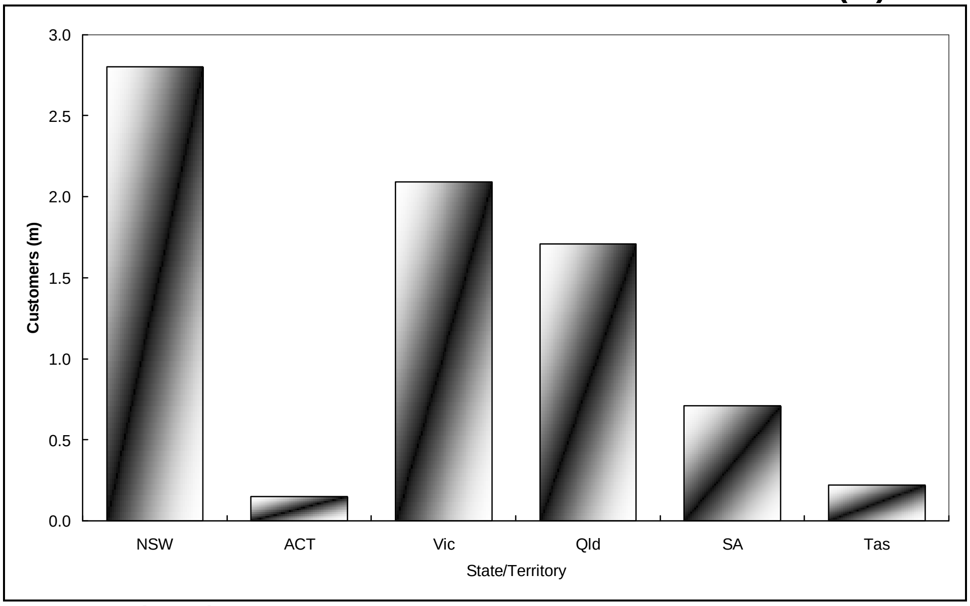
141 Keating, Michael, "Evaluating Energy Prices in NSW", presentation at the Energy Summit Grace Hotel, 20 November 2007.

Figure 4.1
Estimated composition of electricity consumption 2006-07 (PJ)



Source: ABARE, Total Final Electricity Consumption by Industry and Fuel, December 2006.
Note: The New South Wales estimates include consumption in the Australian Capital Territory.

Figure 4.2
Number of residential customers as at June 2007 (m)



Source: UBS, Australian Utilities Structure 2007.

4.3. Market structure

Retailers have been described as occupying three broad categories:[142]

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[142] ESC, Review of the Effectiveness of Retail Competition and Consumer Safety Net in Gas and Electricity, 22 June 2004, p.22.

- incumbent retailers, or local retailers who previously were the franchised operators in a particular state or region;
- full-service (mass market) entrants, or non-incumbent retailers who aim to establish coverage similar to the local retailer. Such a business could be an incumbent from another jurisdiction;
- niche retailers that expect to remain small and who focus on particular classes of customers, distinguishing themselves by offering differentiated products.

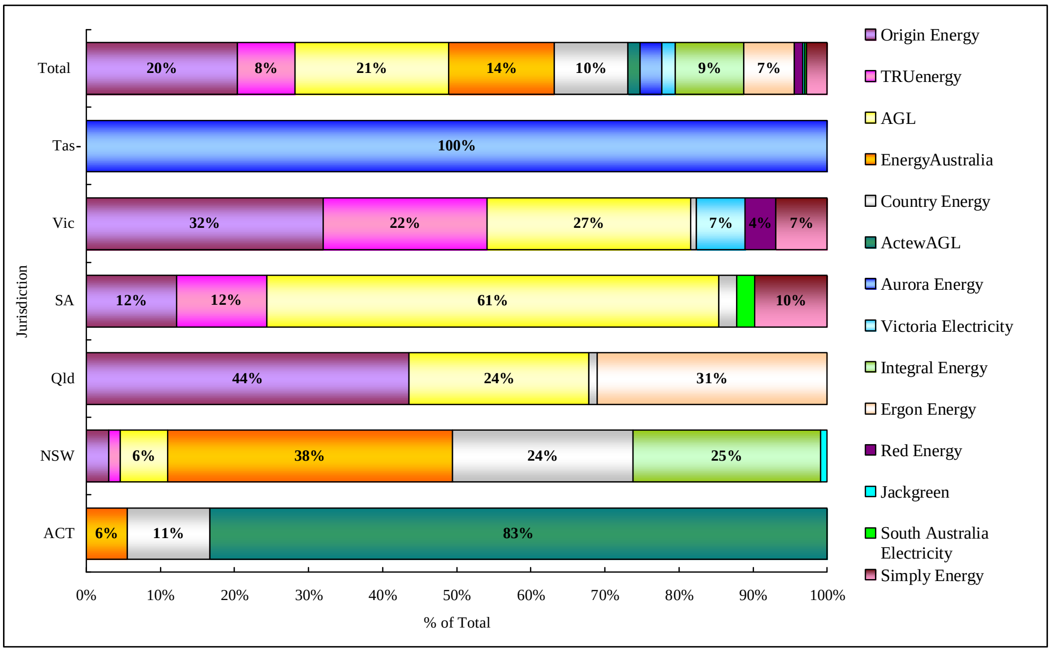
Table 4.2 sets out the estimated number of customers supplied by retailers across each jurisdiction as at June 2007 and Figure 4.3 illustrates the relative market share of each retailer.

Table 4.2 Electricity customers by jurisdiction and retailer as at June 2007 (m)

	ACT	NSW	Qld	SA	Tas	Vic	Total	Total (%)
AGL		0.21	0.47	0.50		0.67	**1.85**	**20.8**
Origin Energy		0.10	0.84	0.10		0.78	**1.82**	**20.4**
EnergyAustralia	0.01	1.26					**1.27**	**14.3**
Simply Energy				0.08		0.17	**0.25**	**2.8**
TRUenergy		0.05		0.10		0.54	**0.69**	**7.7**
Country Energy	0.02	0.80	0.02	0.02		0.02	**0.88**	**9.9**
Integral Energy		0.83					**0.83**	**9.3**
Ergon Energy			0.60				**0.60**	**6.7**
ActewAGL	0.15						**0.15**	**1.7**
Aurora Energy					0.26		**0.26**	**2.9**
Red Energy						0.10	**0.10**	**1.1**
Jackgreen		0.03					**0.03**	**0.3**
South Australia Electricity				0.02			**0.02**	**0.2**
Victoria Electricity						0.16	**0.07**	**1.8**
Total	**0.18**	**3.28**	**1.93**	**0.82**	**0.26**	**2.44**	**8.91**	**100.0**

Source: UBS, Australian utilities structure 2007 (numbers may not add due to rounding).

Figure 4.3
Electricity customers by jurisdiction and retailer



Source: UBS, Australian utilities structure 2007 (numbers may not add due to rounding).

Examining the figure above it is apparent that:

- the incumbent retailers remain dominant in all jurisdictions of the NEM;
- Victoria, New South Wales and South Australia have experienced some market entry, but there do not appear to be significant new entrants in the Australian Capital Territory, Queensland and Tasmania;
- there are several full-service entrants that have been successful in gaining market share, including EnergyAustralia in Victoria, TRUenergy in South Australia and AGL in New South Wales;
- niche retailers have managed to establish customer bases in Victoria, New South Wales and South Australia; and
- across all jurisdictions of the NEM, AGL and Origin are the largest retailers and have the greatest geographic coverage. These are followed in descending order of size by EnergyAustralia, Country Energy, Integral Energy and TRUenergy.

Comparing the market shares presented in the chart above to those contained in the June 2006 report it can be observed that:

- AGL's retail market share has declined in all jurisdictions except Victoria;
- Integral, Origin and Country Energy experienced growth in market share while EnergyAustralia's and TRUenergy's market share declined;
- in Victoria significant ground was gained by Red Energy and Victoria Electricity; and
- the market share of ActewAGL, Aurora and Jackgreen appear to have remained stable over the period.

Table 4.3 on the following pages sets out the licensed retailers operating in the NEM and provides a brief description of the ownership structure and any generation or network interests the retailer is associated with.

Table 4.3 Licensed electricity retailers in eastern Australia

Licensed Retailer	Licensed in more than two jurisdictions?	Licensed in Jurisdiction						Gvt. owned?	Upstream equity interests
		ACT	NSW	Qld	SA	Tas	Vic		
Incumbent Retailers									
ActewAGL (50/50 JV)	ü	06/01	11/96				08/96	ACT gvt (Actew)	Actew: ACT DNSP AGL: see below
AGL	ü	06/01	12/96	12/00	10/99		10/94	û	AGL Hydro, Loy Yang A, Somerton and Torrens Island
Aurora	ü	07/04	02/01	10/06	05/04	12/98	03/01	Tas gvt	Tas DNSP
Country Energy	ü	06/01	11/96	01/98	10/99	06/07	07/98	NSW gvt	NSW DNSP. Wyangala dam, Earthpower Biomass, Lucas Heights Stage II, Teralba Power, Daandine, Oaky Creek, Somerset Dam and Rochendale Renewable Energy Facility
EnergyAustralia	ü	06/01	11/96	01/98				NSW gvt	NSW DNSP
Ergon Energy	û			04/98				Qld gvt	DNSP and TNSP interests in Qld
Integral Energy	ü	06/01	11/96	03/06		12/06	07/98	NSW gvt	NSW DNSP
Origin Energy	ü	06/01	01/97	02/98	10/99		11/95	û	Bulwar Island, Mt Stuart, Roma, Ladbroke Grove, Quarantine and Osborne Generation
TRUenergy (including Yallourn)	ü	06/01	12/96	02/98[1]	10/99	06/07	05/96[2]	û	Yallourn Generator, Hallett Power Station

Licensed Retailer	Licensed in more than two jurisdictions?	Licensed in Jurisdiction						Gvt. owned?	Upstream equity interests
		ACT	NSW	Qld	SA	Tas	Vic		
Other Retailers									
Australian Power & Gas	ü	n.a.	09/06	11/06	11/07	n.a.	10/06	û	n.a.
BHP Billiton Olympic Dam Corporation	û	n.a.	n.a.	n.a.	04/98	n.a.	n.a.	û	Generation via mining operations at Olympic Dam
CitiPower	û	n.a.	01/97	n.a.	n.a.	n.a.	10/94	û	VIC DNSP
Click Energy	û	n.a.	n.a.	n.a.	n.a.	n.a.	06/06	û	n.a.
Cogent Energy	û	n.a.	11/07	n.a.	n.a.	n.a.	01/08	û	Cogeneration facilities at various building sites.
Cowell Electric Supply	û	n.a.	n.a.	n.a.	12/97	n.a.	n.a.	û	Generation and distribution in remote areas.
CS Energy	û	n.a.	n.a.	02/99	n.a.	n.a.	n.a.	Qld gvt	Swanbank, Callide and Mica Creek Generation
Dalfoam	û	n.a.	n.a.	n.a.	12/97	n.a.	n.a.	û	Holds a generation and distribution license.
Delta Electricity	û	n.a.	03/96	n.a.	n.a.	n.a.	n.a.	NSW gvt	Mt Piper, Wallerawang, Vales Point and Munmorah Generation
District Council of Coober Pedy	û	n.a.	n.a.	n.a.	12/97	n.a.	n.a.	SA gvt	n.a.
Diamond Energy Pty Ltd	û	n.a.	n.a.	n.a.	n.a.	n.a.	10/07	û	Tatura biogass generation, 4 planned by 2010.

Licensed Retailer	Licensed in more than two jurisdictions?	Licensed in Jurisdiction						Gvt. owned?	Upstream equity interests
		ACT	NSW	Qld	SA	Tas	Vic		
Dodo Power & Gas	ü	09/07	10/07	11/07	01/08	n.a.	09/07	û	n.a.
Energy Brix Australia Corporation Pty Ltd	û	n.a.	n.a.	n.a.	n.a.	n.a.	02/06	û	Generation in the Latrobe Valley
Eraring Energy	û	n.a.	03/97	n.a.	n.a.	n.a.	n.a.	NSW gvt	Blayney and Crookwell Wind Farms, Brown Mountain, Shoalhaven, Warragamba, Burringjack, Kepit and Hume Hydro and Eraring coal power station
ERM Power Retail Pty Ltd	ü	n.a.	10/07	09/07	01/08	n.a.	n.a.	û	Equity interest in Oakey, constructing Braemar expansion.
Flinders Power	û	n.a.	n.a.	12/07	10/99	n.a.	n.a.	û	Northern and Playford Power Stations
GridX	û	n.a.	05/07	n.a.	n.a.	n.a.	n.a.	û	n.a.
Independent Electricity Retail Solutions Pty Ltd	û	n.a.	07/04	05/07	n.a.	n.a.	n.a.	û	n.a.
Jackgreen (International) Pty Ltd	ü	05/07	03/02	01/07	09/06	n.a.	08/05	û	n.a.
Jeril Enterprises	û	n.a.	n.a.	n.a.	12/97	n.a.	n.a.	û	Holds a generation and distribution license.
Momentum Energy	ü	n.a.	02/07	11/06	10/05	n.a.	01/04	û	n.a.

Licensed Retailer	Licensed in more than two jurisdictions?	Licensed in Jurisdiction						Gvt. owned?	Upstream equity interests
		ACT	NSW	Qld	SA	Tas	Vic		
Municipal Council of Roxby Downs	û	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	SA govt	n.a.
New South Wales Electricity Pty Ltd	ü [3]	n.a.	02/07	n.a.	n.a.	n.a.	n.a.	û	n.a.
OneSteel Manufacturing	û	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	û	n.a.
Our Neighbourhood Energy Pty Ltd	û	n.a.	n.a.	n.a.	n.a.	n.a.	06/06	û	n.a.
Powercor Australia Pty Ltd	û	n.a.	10/96	n.a.	n.a.	n.a.	10/94	û	VIC DNSP
Qenergy Pty Ltd	û	n.a.	n.a.	03/07	n.a.	n.a.	n.a.	û	n.a.
Queensland Electricity Pty Ltd	ü [3]	n.a.	n.a.	09/06	n.a.	n.a.	n.a.	û	n.a.
Red Energy	ü	12/05	05/07	11/05	02/06	n.a.	02/04	NSW, Vic and Cmwlth gvts	Snowy Hydro, the owner, has a number of generation interests in the Snowy region and one in Victoria
Simply Energy[4]	û	n.a.	n.a.	n.a.	05/04[5]	n.a.	06/05	û	Hazelwood, Loy Yang B, Synergen Peaking Units, Pelican Point and Canunda Wind Farm
South Australia Electricity Pty Ltd	ü [3]	n.a.	n.a.	n.a.	09/05	n.a.	n.a.	û	n.a.

		Licensed in Jurisdiction							
Licensed Retailer	**Licensed in more than two jurisdictions?**	**ACT**	**NSW**	**Qld**	**SA**	**Tas**	**Vic**	**Gvt. owned?**	**Upstream equity interests**
SPI Electricity Pty Ltd	û	n.a.	n.a.	n.a.	n.a.	n.a.	10/94	û	n.a.
Stanwell Corporation Limited	û	n.a.	n.a.	02/99	n.a.	n.a.	n.a.	Qld gvt	Barron Gorge, Kareeya, Stanwell, Mackay, Koombooloomba, Windy Hill, Wivenhoe Small Hydro and Toora Wind Generation Assets
Tarong Energy Corporation Limited	û	n.a.	n.a.	02/99	n.a.	n.a.	n.a.	Qld gvt	Tarong and Tarong North, Wivenhoe Dam, Starfish Hill Wind Farm and Mt Millar Wind Farm Generation
Victoria Electricity Pty Ltd	ü 3	n.a.	n.a.	n.a.	n.a.	n.a.	08/02	û	n.a.
Total	**15**	**11**	**22**	**21**	**19**	**4**	**22**	**14**	

Notes:
1. TRUenergy Yallourn, other granted 03/05.
2. TRUenergy Yallourn, other granted 11/97.
3. Victoria, South Australia, Queensland and New South Wales Electricity are the same company.
4. Formerly a partnership between International Power and EnergyAustralia.
5. License first issued to International Power, the license issued under the former JV arrangement was issued in June 2005.
Sources: Various regulator and retailer websites

4.3.1. Observations

Table 4.3 indicates that there are currently 40 distinct licensed electricity retailers in the NEM, although the actual number of licences issued is greater due to some businesses holding multiple retail licences through various subsidiaries. A lesser number of these currently supply or are intending to supply the small retail market.[143]

Fifteen of the retailers listed in Table 4.3 are licensed across more than two jurisdictions, these being: AGL; ActewAGL; Aurora; Australian Power & Gas; Country Energy; Dodo Power & Gas; EnergyAustralia; ERM Energy; Integral Energy; Jackgreen; Momentum Energy; Origin; Red Energy; TRUenergy and the "state" Electricity company. Eight are incumbent retailers in various jurisdictions, and together these accounted for 87 per cent of the retail market across the NEM as at June 2007.

The incumbent retailers, together with Red Energy (which is owned by Snowy Hydro) own various upstream interests. The government owned businesses such as those in New South Wales, Tasmania and, previously, Queensland, are associated with DNSP and/or TNSP assets while the Victorian and South Australian incumbents have reinvested in generation assets in several states. There are also some smaller retailers with interests in generation, particularly those that service remote communities in South Australia.

In addition to the upstream assets listed for each of the retailers in Table 4.3, several retailers have announced their involvement in a number of new generation projects, increasing their interests in generation. These projects include:

§ Spring Gully, a 1000 MW combined-cycle gas-fired plant to be located at the coal seam gas field of the same name and owned by Origin Energy. It will be constructed in two stages with a 500 MW plant expected to be operational by 2008. Origin is also, pending approvals, planning to construct a similarly sized gas-fired plant at Mortlake in western Victoria by 2010;[144]

§ Tallawarra, a 400MW combined-cycle gas-fired plant to be located near Wollongong in New South Wales, is under construction and completion is expected in 2008. It will be owned by TRUenergy;[145]

§ Wellington, a 640MW open-cycle gas-fired plant to be located near Wellington in New South Wales and will be owned by ERM Power. Construction is due to commence in 2009 for operation in 2011; and

§ Bogong, a planned 140MW hydroelectric power plant to be constructed in the Kiewa Valley in Victoria by AGL.[146]

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143 See for example, IPART, Regulated Retail Tariffs and Charges for Small Customers 2007 to 2010: Draft Report and Determination, April 2007, p.24.

144 ASX announcements; Origin website, http://www.originenergy.com.au/about/template.php?pageid=224

145 Rod Myer, "TRU to build $250m plant", The Age, 8 December 2005.

146 AGL website, http://www.agl.com.au/AGLNew/About+AGL/Generation+assets/Projects+under+development/Hydro+electric+power.htm

The table above also brings to the fore a number of changes that have occurred since the original report was published in June 2007 including:

- the granting of retail licences to ERM Power and Dodo Power & Gas across a number of jurisdictions;
- the expansion of Australian Power & Gas, the "state" Electricity Company and Country Energy;
- the decision by International Power to exercise its option to acquire EnergyAustralia's 50 per cent interest in the International Power Partnership now called Simply Energy. As a consequence of this decision EnergyAustralia has had to apply for licenses in South Australia and Victoria to enter as an independent retailer.[147] ESCOSA granted EnergyAustralia a licence in February 2008;[148]
- the decision by Energy One to exit the retail market. This decision followed a period in which wholesale market prices increased substantially. The decision also resulted in the first Retailer of Last Resort event being called in New South Wales, the Australian Capital Territory, Victoria and Queensland; and
- the decision by Momentum Energy to sell its Victorian retail customer base to Australian Power & Gas in July 2007 following a period of high wholesale market prices.[149]

4.4. Retail markets in each state

4.4.1. Queensland

Queensland first introduced retail contestability in 1998 and currently extends this to customers with annual consumption greater than 100MWh. FRC was introduced in July 2007.

Until last year, the Queensland government retained ownership of the entire electricity production chain, aside from a number of merchant generators and non-incumbent retailers. However, the government has since sold the contestable electricity retailing arms of its incumbent energy suppliers, Energex and Ergon, in anticipation of FRC being extended to the entire market in Queensland. Origin and AGL were the purchasers of these spin-offs, called Sun Retail and Powerdirect respectively.[150]

Customer transfer statistics from NEMMCO indicate that the rate of customer churn in New South Wales between March 2007 and February 2008 was approximately 14 per cent.[151] The two incumbent retailers together service almost all retail customers, although this figure may be misleading since it does not indicate the extent to which large customers (which represent a tiny proportion of customer numbers) have switched to alternative providers.

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147 http://www.escosa.sa.gov.au/site/page.cfm?c=2661

148 http://www.escosa.sa.gov.au/site/page.cfm?u=42

149 http://www.momentumenergy.com.au/about-us/newsarchive.aspx

150 Company ASX releases related to the sale.

151 NEMMCO, Retail Transfer Statistical Data; NERA analysis.

Table 4.3 indicates that there are currently 21 retailers licensed to operate in Queensland although it is worth noting that nine of these have entered the market over the past 18 months, in anticipation and response to the development of FRC in Queensland.

4.4.2. New South Wales

There are currently 26 licensed electricity retail operators in New South Wales, although only 22 are shown in Table 4.3 since some larger conglomerates hold multiple licenses through various subsidiaries. The incumbent retailers in New South Wales are EnergyAustralia, Integral Energy and Country Energy and these firms still control 88 per cent of the retail customers in the state, which has declined since the previous report. These firms are all government owned and are also DNSPs, and, in the case of EnergyAustralia, a TNSP. The New South Wales government also currently owns the majority of generation assets in the state. Recent announcements made by the New South Wales Premier indicate that it has accepted the recommendations contained within the Owen Inquiry report and will sell the retail components of the integrated electricity utilities and lease out the generators.[152]

Retail contestability was introduced for customers consuming more than 40GWh in October 1996, but it was not until January 2002 that contestability was rolled out to all customers. The incumbent Victorian firms have captured some customers, with AGL being the most successful by leveraging its gas retail business to offer dual fuel contracts. Niche retailers such as Jackgreen also operate in New South Wales.

Reviews of retail competition in New South Wales show that discounts from the regulated tariffs are available through market contracts of up to 10 per cent, at least in metropolitan markets. There is also some evidence that the extent of these discounts has increased over time.[153] Customer transfer statistics from NEMMCO indicate that the rate of customer churn in New South Wales between March 2007 and February 2008 was approximately 14 per cent.[154]

In a report prepared by the jurisdictional regulator, IPART, it was observed that there are nearly 300 regulated retail tariffs in Country Energy's area, 200 of which are obsolete. It was also noted that in order for a second tier retailer to attract the customers in that area they would need to identify the relevant tariff to offer a discount from.[155] For example, AGL stated:[156]

> *New entrant retailers currently find it difficult to compete in the NSW electricity market as there are numerous regulated tariffs, many of which are obsolete, complex or are under-recovering.*

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[152] Owen Inquiry into Electricity Supply in NSW, September 2007 and Premier of New South Wales, NSW Government acts to secure State's energy supply, 10 December 2007.

[153] IPART, Regulated Retail Tariffs and Charges for Small Customers 2007 to 2010: Draft Report and Determination, April 2007, p.28.

[154] NEMMCO, Retail Transfer Statistical Data; NERA analysis.

[155] IPART, Regulated Retail Tariffs and Charges for Small Customers 2007 to 2010: Draft Report and Determination, April 2007, p.21.

[156] AGL Submission to IPART Issues Paper on Price Determination, October 2006, p.9.

4.4.3. Australian Capital Territory

FRC was introduced in the Australian Capital Territory in 2003. There are 11 electricity retailers licensed to operate in the Australian Capital Territory, all of these being retailers that have also entered, or are incumbents in, New South Wales.[157] Notwithstanding the introduction of FRC the incumbent provider, ActewAGL, still services almost all retail customers. Actew ACT, a 50 per cent partner in the joint venture with AGL in ActewAGL, is also the DNSP for the Territory, whilst AGL has a number of generation interests, including some hydroelectric capacity in New South Wales.

4.4.4. Victoria

Victoria was the first jurisdiction in the NEM to introduce retail contestability for large customers and it implemented FRC in January 2002.

Government ownership of incumbent retailers was relinquished early in the reform process, and the retail functions were vertically separated from the network providers and generation. However, re-integration in recent years has seen AGL, Origin Energy and TRUenergy acquiring various generation assets in the Victorian and South Australian regions.

These remain the prevailing retailers in the market, accounting for about 82 per cent of the retail electricity customers in the state. Other retailers that have managed to establish significant customer bases are Simply Energy (formerly a partnership between International Power and EnergyAustralia), Red Energy and Victoria Electricity. Customer transfer statistics from NEMMCO indicate that the rate of customer churn in Victoria between May 2006 and April 2007 was approximately 25 per cent, with the majority of the 600,000 transferring customers leaving their franchised provider to seek a market contract with an alternative provider, or churning between alternative providers.[158] The ESC also recently released a report stating that 2006-07 was a record year for customer transfers with over 621,000 customers switching.[159]

Evidence in a recent review of the effectiveness of retail competition in Victoria indicated that customers on market contracts were able to achieve discounts of as much as 20 per cent from the regulated retail tariffs.[160] Following its review of the effectiveness of retail competition in Victoria, the AEMC has recommended that from 1 January 2009 standing contract prices no longer be regulated.[161]

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157 NEMMCO transfer data amalgamates the Australian Capital Territory and New South Wales and hence we have been unable to report separate churn rates.

158 NEMMCO, Retail Transfer Statistical Data; NERA analysis.

159 ESC Media Release, Energy Switching At Record Levels, 20 December 2007.

160 ESC, Review of the Effectiveness of Retail Competition and Consumer Safety Net in Gas and Electricity, 22 June 2004, p.35.

161 AEMC, Review of the Effectiveness of Competition in the Electricity and Gas Retail Markets – Victoria, www.aemc.gov.au.

4.4.5. South Australia

South Australia introduced FRC in January 2003 and there are now 19 licensed retailers operating in the state, with many of these entering since the introduction of FRC. The incumbent retailer is AGL, which serves about 60 per cent of customers in South Australia. However, TRUenergy, Origin and Simply Energy (formerly a partnership between International Power and EnergyAustralia) have also managed to accumulate significant numbers of retail customers.

The NEMMCO retail customer transfer statistics over the period from March 2007 to February 2008[162] indicate that, along with Victoria, South Australia is the most active retail electricity market in Australia with annualised churn of 28 per cent. This places these states as the second and third most active retail markets in the world behind New Zealand, which has a longer history of FRC.[163] As is the case in Victoria, the dominant providers in South Australia also have interests in generation capacity.

4.4.6. Tasmania

Tasmania joined the NEM with the completion of the Basslink interconnector in 2006 and has therefore only recently entered a reform path towards FRC. Currently retail competition is open to customers with annual usage of more than 20GWh.

Integral Energy, TRUenergy and Country Energy are currently the only retailers to have entered into competition with the incumbent firm Aurora Energy (which is also the DNSP in the state). The latter two, Country Energy and TRUenergy, have only received electricity licenses in the last year.

Given the small number of contestable customers, it is not surprising that Aurora is still the retailer to almost all Tasmanian customers. Further market entry may be expected as Tasmania proceeds with its reforms, which are currently scheduled to result in FRC by July 2010, subject to a public benefits test.

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[162] NEMMCO, Retail Transfer Statistical Data; NERA analysis. Data for South Australia was not available prior to October 2006.

[163] IPART, Regulated Retail Tariffs and Charges for Small Customers 2007 to 2010: Draft Report and Determination, April 2007, p.72.

5. Vertical integration in the NEM

As an approach to manage risks associated with price volatility in the NEM, a number of retailers have purchased interests in generation, to create a natural hedge.[164] There are four electricity retail businesses that have some generation interests including AGL, Origin Energy, TRUenergy and International Power.[165]

In this section we outline the relationship between AGL, Origin, TRUenergy and International Power and their generation interests.

5.1. AGL

Over the last five years AGL has actively sought to increase its interest in upstream generation assets as a way of ameliorating the wholesale price risk and earnings volatility faced by its retail arm. The portfolio of generation assets that AGL has since developed is diverse consisting of thermal and renewable base load as well as intermediate and peaking generation assets across Victoria, South Australia and New South Wales.

As at March 2008 this portfolio consisted of, among others:

§ The 150MW Somerton gas fired power plant that was constructed in 2002 (Victoria);

§ a 32.5 per cent interest in the 2120MW Loy Yang A coal fired power plant that was acquired in April 2004 (Victoria); and

§ AGL Hydro Victoria and AGL Hydro New South Wales that were acquired in November 2005 as part of the Southern Hydro acquisition (approximately 646 MW in total Hydro assets).

In addition, a major boost to AGL's generation was achieved through the asset swap involving TRUenergy's Torrens Island gas fired power station in South Australia and the Hallett gas fired power station. As a result of this transaction AGL now owns the Torrens Island gas fired power station.

In addition to these assets AGL has proposed a number of gas, hydro and wind generation developments including a joint venture with CS Energy at Mica Creek (gas fired), Leafs Gully (coal seam methane fired which will utilise gas from AGL's upstream interest in the Sydney Gas Co.), Townsville (gas fired), Bogong (hydro), McKay Creek (hydro) and the Hallett wind farm.

AGL's diversity of generation assets has been a deliberate strategy as noted in statements made following the acquisition of Southern Hydro and in the lead up to the acquisition of the Torrens Island Power Station.

> *"The new hydro facilities acquired by AGL have added significant value to the generation portfolio because of their ability to start up almost instantaneously….In a market where there is a wholesale electricity price set for each five-minute period, this fast start capability helps*

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164 We outline briefly in section 9 some of the implications arising from increased vertical integration in the NEM.

165 Although NRG Flinders holds a license to retail in South Australia it does not appear to have operated as a retailer.

> *offset exposure to the potentially high spot prices that AGL would otherwise face in order to meet customer demand."*[166]
>
> *"Developing means to physically manage the price risk of a large retail base is a key financial risk mitigate, and this acquisition represents a significant leap forward in our strategic intent….Deepening our position in vital peaking and intermediate capacity plant like Torrens Island will afford AGL the direct and physical means to lower cost of goods sold and allow AGL to reduce its exposure to high cost hedge products due to the enhanced portfolio benefits of the acquisition."*[167]

5.2. Origin Energy

Origin has also sought to mitigate the price risks faced by its retail arm by holding interests in generation assets. However, unlike the diversified nature of AGL's portfolio, Origin's portfolio consists primarily of cogeneration plants and gas fired power plants in Western Australia, Queensland and South Australia.

The gas fired power generation assets currently held by Origin include:[168]

§ the 288 MW Mt Stuart Power Plant located in Queensland (peaking plant);

§ the 74 MW Roma Peaking Plant located in Queensland (peaking plant);

§ the 96 MW Quarantine Power Station located in South Australia (peaking plant);

§ the 32 MW Bulwar Island Power Station located in Queensland (base load);

§ the 180 MW Osborne Power Station located in Queensland (base load); and

§ the 80 MW Ladbroke Grove Power Station located in South Australia (peaking plant).

The output from Roma, Quarantine and Ladbroke Grove is also contracted to Origin Retail.[169]

Origin is currently in the process of developing two new gas fired power plants in Victoria (the Mortlake power station) and Queensland (the Spring Gully power station). Both of these developments will use gas from Origin's upstream gas production interests in the Otway Basin and the Spring Gully coal seam methane fields.[170,171] Origin has also committed to the development of the Darling Downs power station, which will be a 630 MW gas-fired generator. Origin has also proposed to expand the capacity of the Quarantine power station by 120 MW.

The gas fired power generation assets have principally used gas from Origin's upstream gas production interests in the Cooper/Eromanga and Otway basins and thus the development of this portfolio of generation assets has:

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166 AGL, Annual Report 2006, p.17.

167 AGL, Media Release, 29 January 2007.

168 Origin Presentation, Morgan Stanley Asia Pacific Summit Singapore, November 2007.

169 Origin website, http://www.originenergy.com.au/about/template.php?pageid=289.

170 Origin website, http://www.originenergy.com.au/about/template.php?pageid=1376

171 Origin webstie, http://www.originenergy.com.au/about/template.php?pageid=1510

- provided a market for the gas produced in fields within which Origin has a joint venture interest; and
- been designed to provide a natural hedge against wholesale electricity price shocks.

This strategy can be seen in the following statements made by Origin:

> *"The development of Quarantine Power Station provides markets for natural gas and an internal hedge against retail electricity exposure to volatility in electricity pool prices."*[172]
>
> *"By participating in fuel supply, generation and retail sales Origin Energy is able to create additional value while effectively managing its risk exposure.*[173]

5.3. TRUenergy

As at March 2008 TRUenergy's generation interests included the 180 MW Hallett power station in South Australia and the 1480MW coal facility at Yallourn in Victoria. TRUenergy is also currently in the process of developing the 400 MW gas-fired plant in Tallawarra that is scheduled to be completed for the summer of 2008-09.[174]

5.4. International Power

International Power retails electricity in both Victoria and South Australia through its retail arm, Simply Energy.[175] As at March 2008, International Power's generation capacity included the:

- 485 MW CCGT plant at Pelican Point;
- 46 MW Canuda Wind Farm;
- 360 MW of peaking generation using natural gas/distillate which includes units at Mintaro, Dry Creek, Port Lincoln and Snuggery;[176]
- 92 per cent share of the 1600MW Hazelwood coal power station; and
- 70 per cent share of the 1000MW Loy Yang B coal power station.[177]

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172 Origin Energy, Annual Report 2002, p.6.

173 Origin Energy, Annual Report 2002, p.8.

174 TRUenergy website, http://www.truenergy.com.au/Production/Tallawarra/Index.xhtml

175 International Power, http://www.internationalpower.com.au/Page.php?iPageID=106.

176 International Power does not own Mintaro, Dry Creek, Snuggery or Port Lincoln but operates them under a long term lease under Synergen Power which also provides ancillary services.

177 International Power website, http://www.internationalpower.com.au/Page.php?iPageID=141

6. Operation of the NEM

NEMMCO was established under the Rules as a not-for-profit independent electricity market and system operator. In this role, NEMMCO is responsible for the operation of the NEM, maintaining system security and the co-ordinated planning of the network.

Within the wholesale market, NEMMCO's responsibility is to balance supply and demand through a centrally co-ordinated real time dispatch process. In doing so, NEMMCO conducts a sequence of activities that facilitates trade between generators and consumers of electricity. In this section we provide an overview of NEMMCO's role in the operation of the NEM.

6.1. Pre-dispatch

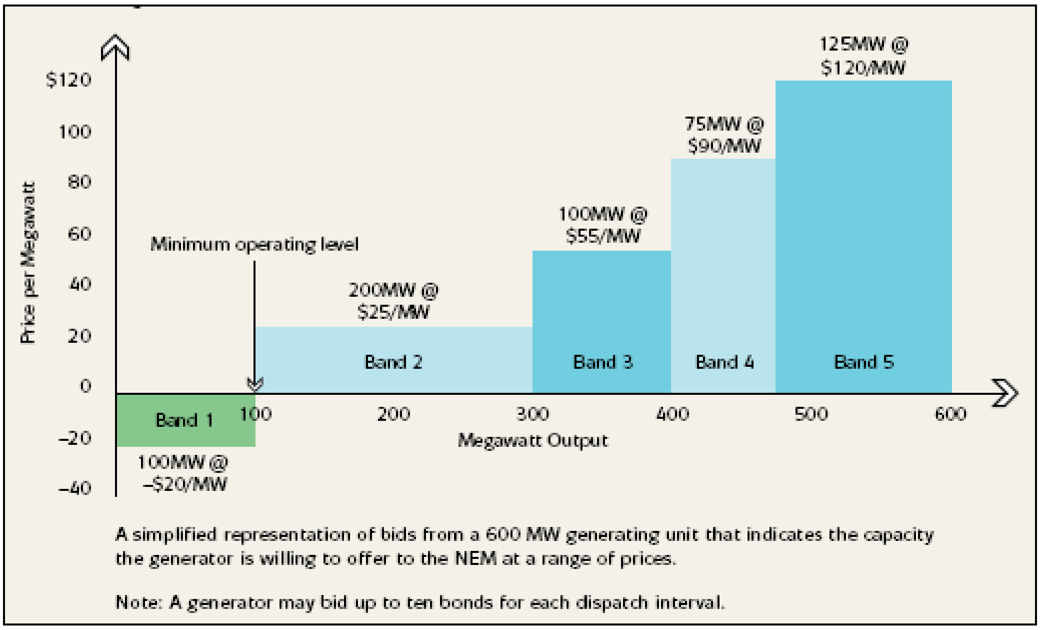
Prior to dispatching generators, NEMMCO publishes a pre-dispatch schedule that sets out supply and projected demand for all trading intervals (30 minute periods) over the following two days.

In accordance with the Rules, registered scheduled generators are required to submit bids for particular quantities of electricity two days ahead of the supply requirement for each of the 48 trading intervals in that day. These bids specify the quantities that each generator is willing to supply at nominated prices.

For some quantities of supply, generators will bid a negative price, reflecting its minimum operating level. This negative price reflects the costs associated with shutting down and subsequently having to start the plant which may exceed the cost of a generator paying to continue generating at a negative price.

When submitting bids to NEMMCO, generators are permitted to bid production quantities in up to ten price bands, with each band representing an incremental amount of generation. This bidding approach is illustrated in Figure 6.1 below.

Figure 6.1
Bid Structure



Source: NEMMCO.

The Rules allow for three types of bids, each of which are subject to a floor price of -$1,000 and a ceiling price of $10,000 per megawatt hour.[178]

- **daily bids** are submitted on the day before supply is required and are incorporated into the forecasts that are prepared prior to dispatch;
- **re-bids** can be submitted up to five minutes before dispatch and allow the generator to alter the quantity of electricity it will supply, however generators are not permitted to change the price of the bid; and
- **default bids** are those that stand when no daily bid has been made, they generally are 'commercial-in-confidence' and reflect the base operating level of a given generator.[179]

6.2. Dispatch process and the spot price

In the dispatch process, once the bid stack has been formed, NEMMCO uses this information to dispatch generators into production every five minutes. The price at which the generators are dispatched (otherwise known as the dispatch price) is calculated by reference to the bid submitted by the most expensive generator that is required to be dispatched into production.[180] The spot price is calculated every half hour by averaging the six dispatch

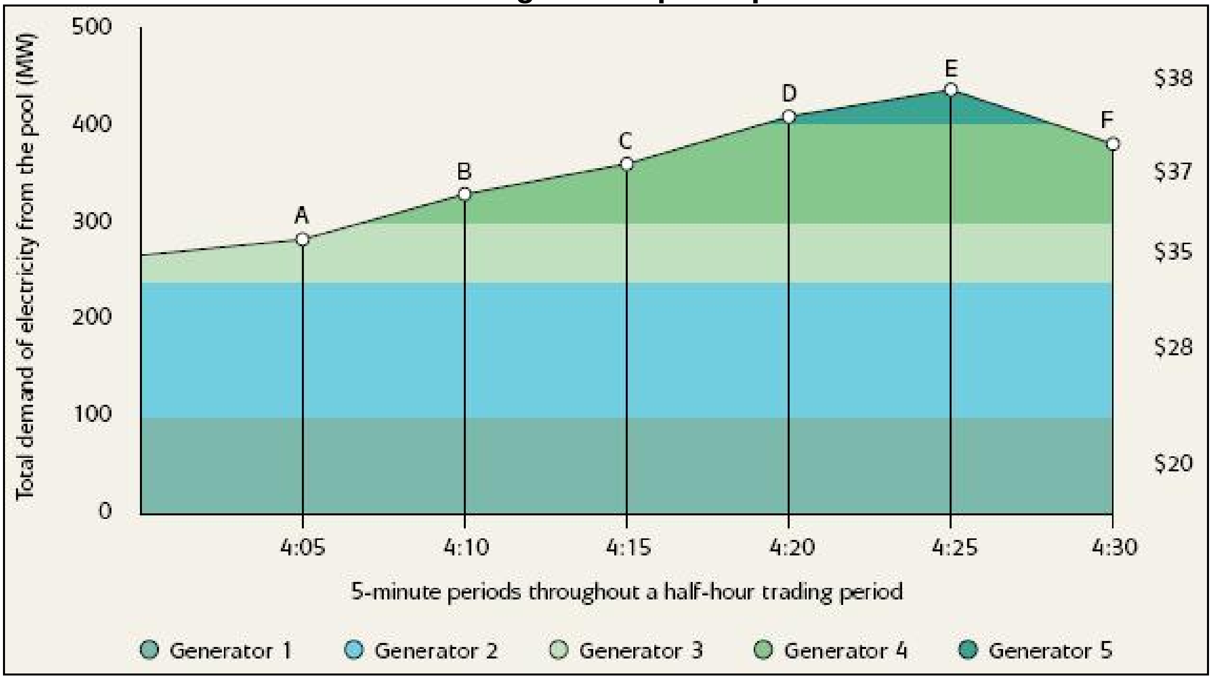
[178] This is also known as the value of lost load (VoLL) and represents the assessed value of the load that cannot be supplied in the event of a supply shortfall. The VoLL is reviewed on an annual basis and is determined by the Reliability Panel. The VoLL is intentionally set at a high level to encourage participants to manage this financial risk by entering into financial contracts. The price of these contracts is then intended to act a signal for new investment.

[179] NEMMCO, An Introduction to Australia's National Electricity Market, 2005, p. 12.

[180] The technical requirements of the transmission system may at times require generators to be dispatched out of price order due to a locational need in the system.

prices that occurred during that interval. This derivation of the dispatch price and spot price can be seen in Figure 6.2.

Figure 6.2
Scheduling and dispatch prices



Source: NEMMCO.

The process for calculating the dispatch and spot price in the above figure can be outlined in the following steps:

A. At 4:05 pm, Generators 1 and 2 are fully dispatched and Generator 3 is only partially dispatched. Since Generator 3 is the most expensive bid the dispatch price at 4.05 is $35 per MWh.

B. At 4:10 pm, demand has increased: Generators 1, 2 and 3 are fully dispatched, and Generator 4 is partially dispatched. The dispatch price at 4.10 rises to $37 MWh in line with Generator 4's bid.

C. At 4:15 pm demand has increased by a further 30 MW which is still within the range that can be supplied by Generators 1, 2, 3 and 4. The dispatch price therefore remains at $37 MWh.

D. By 4:20 pm, demand has increased to the point that supply from Generator 5 is required to meet demand. The dispatch price at 4.20 therefore rises to Generator 5's bid of $38 per MWh.

E. At 4:25 pm, demand remains within the range that can be supplied by Generators 1-5 and thus the dispatch price remains at $38 per MWh at 4.25.

F. By 4:30 pm, demand has fallen such that Generator 5 (the most expensive generator) is no longer required and Generator 4 is only partially dispatched. The dispatch price at 4.30 returns to Generator 4's bid price of $37 per MWh.

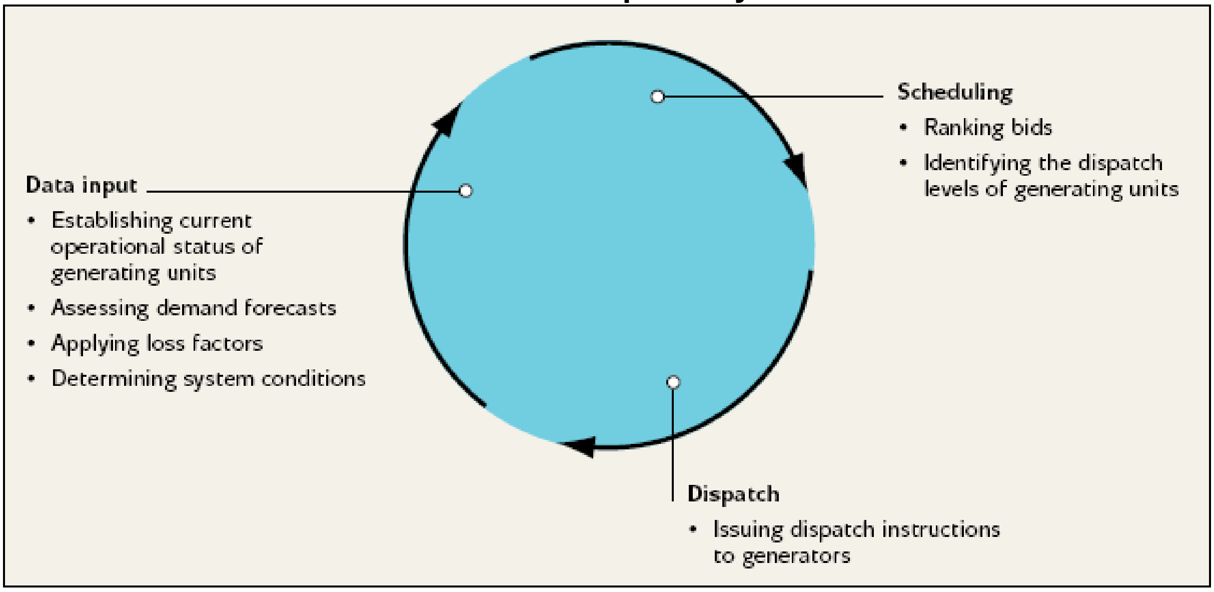
The spot price for the trading period is calculated as the average of the six dispatch prices. That is, $(35 + 37 + 37 + 38 + 38 + 37)/6 = $37 per MWh. This is the price all generators receive and the price all retailers pay.

In terms of the NEM, each of the six interconnected regions has its own reference node that is used to determine the regional spot price. The spot price in each region may diverge from that of its neighbours at any point in time for a multitude of reasons including energy losses and system outages. However the primary cause of significant price differentials between regions is the physical limits on interconnection capacity. By way of example, if the import interconnection capacity into a region is reached, NEMMCO must schedule generators from within the region to meet demand even though generators in another region may be willing to supply at a lower price, hence creating a price differential across regions.

In terms of dispatching generators into production, NEMMCO not only takes into account network constraints, but also changes on the demand side. For instance NEMMCO has sensitive monitoring equipment that determines micro-variations in demand, meaning that dispatch is adjusted as often as every four seconds.[181] Such changes are implemented in the NEM through ancillary services that provide for an increase or a decrease in output by means of the contact that generators have with NEMMCO's control centres.[182] These ancillary services include frequency control ancillary services, ancillary generation and voltage control.

The dispatch cycle is illustrated below.

Figure 6.3
Generator dispatch cycle



Source: NEMMCO.

6.3. Settlement of transactions

In the settlement process NEMMCO acts as a clearing house and is responsible for calculating the liability of a particular customer and transferring funds to the generator. A customer's liability is calculated daily by reference to the spot prices prevailing in the region within which the customer operates and the quantities are consumed. The consumption levels

181 NEMMCO, Australia's National Electricity Market: Wholesale Market Operations, p.14.

182 Ibid.

are obtained from metering data that records the electricity consumption and the time of that consumption for a particular customer. The funds collected by NEMMCO from each customer are then transferred to the generators. As with other clearing houses, NEMMCO imposes a number of prudential requirements on end users. Specifically, NEMMCO requires end users to obtain bank guarantees and to maintain security deposits. Customers are also subject to a maximum daily credit limit that requires daily settlement.

6.4. Maintaining the demand and supply balance in the wholesale market

To ensure demand and supply are balanced and that the integrity of the market is maintained NEMMCO has the power to intervene in the market in certain circumstances. For example, if demand exceeds supply and the ceiling bid of $10,000 per megawatt hour is triggered then NEMMCO can instruct generators to supply more capacity than they have bid into the market. If NEMMCO anticipates that supply will fall below a defined reliability standard then it may act as a reserve trader and enter into reserve contracts with generators for the provision of reserve capacity ahead of the expected shortfall. As a last resort NEMMCO may instruct network service providers to commence load shedding. All of these actions are designed to ensure that the security of the system is maintained and that supply and demand is balanced.

Demand side participation is also encouraged and facilitated by the publication of demand forecasts by NEMMCO on a seven day and two year basis. These forecasts are updated regularly and allow retailers or large customers to voluntarily withdraw from the market if a particular spot price is reached.

6.5. Planning and development of the wholesale electricity market

As the market and system operator NEMMCO is also responsible for identifying investment opportunities in both generation capacity and transmission network augmentation. The identification of these opportunities is facilitated through the inter-regional planning committee. This committee assists NEMMCO in the preparation and annual publication of both:

§ the Statement of Opportunities, which identifies opportunities for future investment in generation capacity over a ten year period; and

§ the Annual National Transmission Statement, which identifies technically feasible modifications that can be implemented to address both current and forecast system constraints on the transmission network.

6.6. Energy Losses

Losses consist of electrical losses, metering errors and theft. They account for approximately 10 per cent of total energy produced in Australia.[183] Generally speaking, there is a trade-off between network utilisation and losses (ie., as network assets are driven harder and asset utilisation improves, losses will increase). Losses also increase with the distance that energy must be transferred. The Rules distinguish between transmission losses, measured via

183 NEMCO, An Introduction to Australia's Electricity Market, 2005, p.18.

transmission loss factors (TLFs) and distribution losses, measured via distribution loss factors (DLFs).

There are three types of losses:

- *Inter-regional losses* – the losses from transporting electricity between two regional reference nodes along regulated interconnectors. NEMMCO is required to approve an equation for estimating losses, where that equation is expressed in terms of significant variables. It would appear to follow that the loss factor is recalculated for each trading interval depending upon how those variables change. The loss factor must represent the marginal losses suffered. The surplus accruing from the fact that marginal losses generally exceed average losses is treated as an inter-regional settlement residue and is dealt with in the same way as other inter-regional settlement residues.
- *Intra-regional losses* – the losses from transporting electricity between the regional reference node and any transmission connection point (transmission connection points include points of generator connection and connections to distribution networks). NEMMCO approves (static) loss factors for each transmission connection point for the year in advance (albeit with an ability to respond to new generators and other significant changes). The loss factors must represent the average of the marginal electricity losses expected in each trading interval over the year. The surplus accruing from the fact that marginal losses generally exceed average losses is treated as a settlement residue and is distributed to the TNSP (to be offset against the revenue permitted to be earned from transmission prices).
- *Distribution losses* – the losses incurred in conveyance of electricity over a distribution network. The jurisdictional regulator must approve (static) distribution loss factors for each distribution connection point annually, in advance of the relevant year (albeit with an ability to respond to new generators and other significant changes). The loss factors must reflect the average electricity lost when conveying electricity between a transmission connection point and a distribution connection point. The 'losses' derived by multiplying the loss factors by throughput are required to equate to forecast total losses – so no surplus should be expected.

The loss factors may be:

- site specific (where size thresholds are passed or where an embedded generator wishes to have a site specific distribution loss factor and is prepared to pay for its calculation); or
- averaged across the distribution network connection points in the relevant voltage class that is assigned to a particular transmission connection point.

6.6.1. Treatment of energy losses

Loss factors are important to the NEM dispatch and settlement processes.

6.6.1.1. Dispatch

Central dispatch is based on (amongst other things) generator bids (clause 3.8.1). The bids that a scheduled generator submits are its bid to supply energy at that generator's connection point. The generator's bid is then adjusted to derive the 'offer' that is used in the central dispatch process (the objective being to reference the bid to the regional reference node) – which is achieved by dividing the bid by the applicable loss factor (clause 3.8.6(g)). If a generator is connected to the distribution network, the applicable loss factor is the product of its distribution loss factor and the intra-regional loss factor that is assigned to the generator (applying to the transmission connection point of the distribution network in which the generator is located).

6.6.1.2. Settlement

The local spot price for each transmission connection point is the regional reference price multiplied by the intra-regional loss factor (clause 3.9.1(c)). The amount that a generator gets paid (or a retailer pays) is the product of (clause 3.15.6):

- the regional reference price;
- the intra-regional loss factor at the transmission connection point at which the generator connects or which is assigned to an embedded generator; and
- the 'adjusted gross energy'.

Hence, the price received (the outworking of the first two terms) is the 'local spot price' for the relevant transmission connection point. 'Adjusted gross energy' for an embedded generator is measured energy multiplied by the distribution loss factor (measured energy is positive for generators, and negative for end users).

6.6.1.3. The outcome for embedded generators

When determining which generators are dispatched, the NEM takes into account the losses incurred (or avoided) by embedded generators. Specifically:

- The bids of all generators are adjusted to take account of the losses incurred (or avoided) when conveying electricity to the regional reference node, which includes losses incurred (or avoided) on the distribution network; and
- If the embedded generator is in an energy importing region, then its intra-regional and distribution loss factors will be greater than one, and so its bids will be scaled down when being compared to other generators (whereas generators that are in generation rich areas will have an intra-regional loss factor that is less than 1, and so their bids will be scaled up).

The price that an embedded generator gets paid reflects the losses incurred (or avoided) when transporting electricity from the regional reference node to its transmission connection point. Specifically:

- The price that all generators are paid is their local spot price, which is the regional reference price multiplied by the intra-regional loss factor; and
- If the embedded generator is in an energy importing region, then its intra-regional loss factor will be greater than one and hence it will receive a higher price than the regional reference price.

The output that an embedded generator gets paid for reflects the losses incurred (or avoided) on the distribution network. Specifically:

- The amount that the embedded generator is paid for is its output multiplied by its distribution loss factor; and
- If the embedded generator is in an energy importing area, then its distribution loss factor will be greater than one, which means that it is deemed to be avoiding losses and it will get paid for more than it produces.

In summary, a loss factor of greater than one is good for a generator, as such a loss factor scales down its price offer (and hence increases its likelihood of being dispatched), scales up the price it receives (as it receives its local spot price) and – for embedded generators – scales up the quantities it sells (by its distribution loss factor). Conversely, a loss factor of greater than one is bad for a retailer, as such a loss factor scales up the price it pays for electricity delivered to the transmission connection point associated with a particular customer and scales up the quantities it buys on behalf of that customer (by the distribution loss factor).

6.7. Constraints

The transportation of electricity through the NEM is limited by the technical capacity of the interconnectors and the distribution network. Technical capacity refers to the quantity of electricity each section of the NEM can handle. If these constraints are exceeded then the security and reliability of the system would be compromised.

If the system were operating without constraints, NEMMCO would dispatch generators purely on the basis of cost. However this is not the case and NEMMCO takes into consideration the capacity of the entire system when dispatching generators into production. For instance if the interconnector to region A is at maximum capacity, NEMMCO must, in order to satisfy demand, dispatch generators from region A even if electricity can be produced at a cheaper price elsewhere.

As with energy losses, the presence of constraints can lead to differences between regional reference spot prices.

7. Risk management

7.1. Overview

Managing the risks inherent in operating in the NEM is important for all market participants. Parties participating in the NEM face three forms of risk: market risk, credit risk and settlement risk.[184]

The remainder of this section provides an overview of the risks faced by market participants, the tools used to manage these risks and some discussion of the effectiveness of these tools.

7.1.1. Market Risk

Market risk refers to the exposure of participants in the NEM to fluctuations in the price of electricity on the spot market. As established in section 2.3.3, prices in the NEM exhibit volatility. This arises because electricity is a non-storable commodity, meaning fluctuations in demand and supply cannot be smoothed through the use of inventories. Instead, supply and demand are balanced in the spot market through the price mechanism.

The volatility of prices is compounded when one takes into account the regional structure of the NEM. If participants are trading or using contracting positions in one region to support activities in another, then they are exposed to the risk that the spot price will differ between the two regions (this is known as inter-regional risk).

The cause of fluctuations in demand and supply include:

§ changes in temperature which create demand peaks;

§ unplanned generator outages; and

§ transmission/interconnector line failures.

The presence of such fluctuations is evident in the first three months of 2007 where the price of electricity in the spot market ranged from a low of -$999 to a high of $10,000 per MWh.[185]

Market risk also refers to the financial risk that arises due to uncertainty associated with volume. Given that demand for electricity can be quite volatile, retailers face the risk that any uncontracted load may occur when the spot price is high. On the other hand, generators face the risk that they may not be able to meet their contracted supply due to planned or unplanned outages.

7.1.2. Settlement Risk

Settlement risk arises from the potential for non-payment for the purchase of electricity by a participant in the NEM. This risk primarily applies to retailers and the requirement that they make payments for electricity by the date of settlement.

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[184] NEMMCO, Australia's National Electricity Market: Trading Arrangements in the NEM, p. 12.

[185] NEMMCO Market Data.

7.1.3. Credit Risk

Credit risk is the risk associated with a loss arising from a market participant experiencing a credit downgrade. Such a downgrade could potentially lead to the participant being unable to meet their payment obligations. In practical terms this form of risk is equal to the credit exposure of the firm and the probability of a change in credit status.

7.2. Tools to manage market risk

There are a range of tools available to manage market risk including derivatives, the Settlement Residue Auction, government instruments and vertical integration. The remainder of this section provides an overview of these tools.

7.2.1. Derivatives

The primary objective of generators and retailers when managing market risk is to lock in the future price of electricity that will be supplied or purchased. The most common means of achieving this objective is through the use of financial derivatives.[186]

A derivative is a financial instrument that derives its value from the trading of rights or obligations relating to an underlying asset, in this case a specific quantity of electricity. All derivatives associated with the NEM are settled on a cash basis, since the NEM is operated as a gross pool which prohibits the direct physical delivery of the underlying asset.

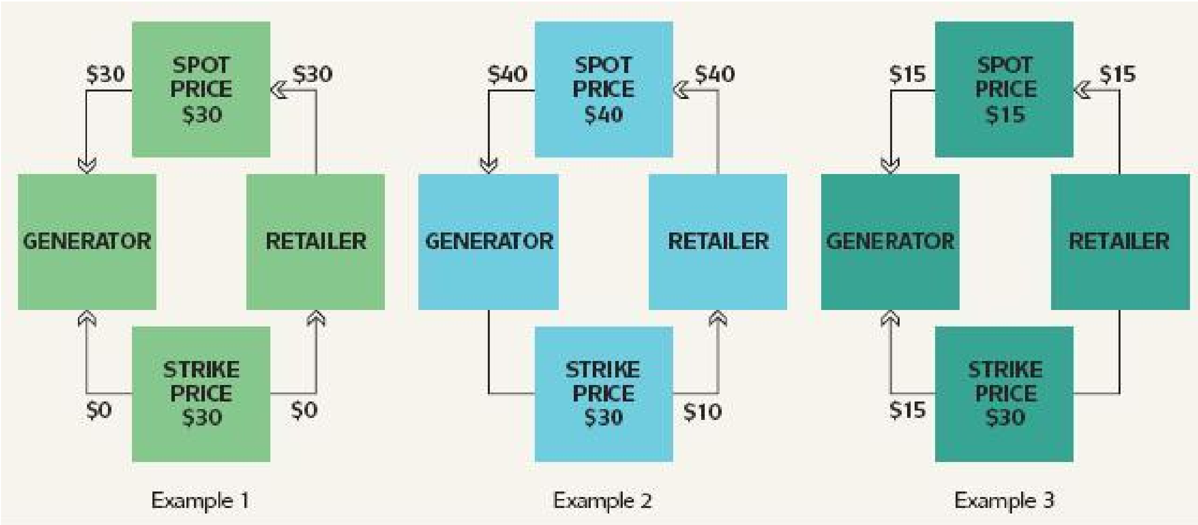
The primary derivatives used to manage market risk in the NEM are swaps, options and futures.

7.2.1.1. Swaps

A swap is an instrument whereby two parties agree to exchange the cash flows on a nominal principal amount. In relation to an electricity swap, the key components are the spot price, the quantity to be traded and the maturity date.

[186] NEMMCO, Australia’s National Electricity Market: Trading Arrangements in the NEM, p. 25.

Figure 7.1
Swap arrangements



Source: NEMMCO.

For example, consider a retailer needing to purchase 10MWh of electricity in one year and is concerned that the price of electricity might rise over the next twelve months. The retailer could manage this risk by purchasing an electricity swap for 10MWh at a price of $30 per MWh (this is known as the strike price), thereby locking in the price for the supply of its electricity. If the price of electricity in one year's time was $40 per MWh then the generator would compensate the retailer the $10 per MWh by which this exceeds the strike price. On the other hand if the price of electricity fell to $15 per MWh the retailer would pay $15 per MWh on the spot market but would also be required to compensate the generator $15 per MWh. Thus in every possible scenario the retailer would pay (and the generator would receive) $30 per MWh on the specified volume of electricity irrespective of the outturn spot price.

In regards to the NEM, swaps can be purchased in three ways:

- directly from other market participants;
- through a broker; or
- on the Sydney Futures Exchange (SFE).

The advantage of purchasing a swap directly from a market participant or through a broker is that it is contracted over-the-counter (OTC). This essentially means that the contract is not standardised and instead can be tailored to suit the requirements of both market participants. In the case of broker-traded derivatives, prices for the products are shown on screens and participants can agree to the prices electronically thereby eliminating the need to search for counterparties.

7.2.1.2. Options

An option is an instrument that gives the holder the right but not obligation to purchase or sell the underlying asset at a predetermined price (the strike price) in the return for the payment of a premium. In relation to electricity, an option gives the holder the right to purchase or sell a specific quantity of electricity at the strike price on a specified date.

Like swaps, options can be purchased either OTC or through an exchange. However unlike options, the holder can protect themselves against adverse price movements whilst still retaining the ability to benefit from positive price changes. This key feature arises due to the fact that an option gives the holder the right but not obligation to exercise the instrument. Hence if the price were to move favourably then the holder would not exercise the option and simply forgo the premium they paid to acquire the instrument.

Options primarily come in two forms: ‘put’ options and ‘call’ options. A put option gives the holder the right, but not obligation, to sell electricity at a predetermined price whilst a call option gives the holder the right, but not obligation, to purchase electricity at a predetermined price. A generator would therefore use put options to construct a price floor whereby it could guarantee itself a minimum price (the strike price) should the spot price of electricity fall. On the other hand, a retailer would use call options to construct a price cap to set an upper limit on the price they would need to pay for electricity.

It is also possible to construct a price ‘collar’ which combines both put and call options. The purpose of such a strategy is to construct a band within which the price of electricity is allowed to vary. Whilst such a strategy may at first appear illogical, it is often the case that a zero premium payment is required by sharing the upside and downside risk in this fashion. For instance in the case of a retailer, the cost of buying a call option can be offset by the premium earned through selling a put option.[187]

In addition to put and call options, participants in the NEM can purchase a swaption to hedge against adverse price movements. As the name suggests, a swaption is an instrument which gives the holder the right but not the obligation to enter into a swap agreement. In many respects they are similar to price caps and floors since they can be used to set a minimum price for the purchase or sale of electricity.

Whilst participants in the options market are generally those who have a physical commitment in the NEM, ie, retailers and generators, other parties such as banks and traders are active players in the market. These parties look to profit from the premiums earned when options are abandoned by buyers.[188]

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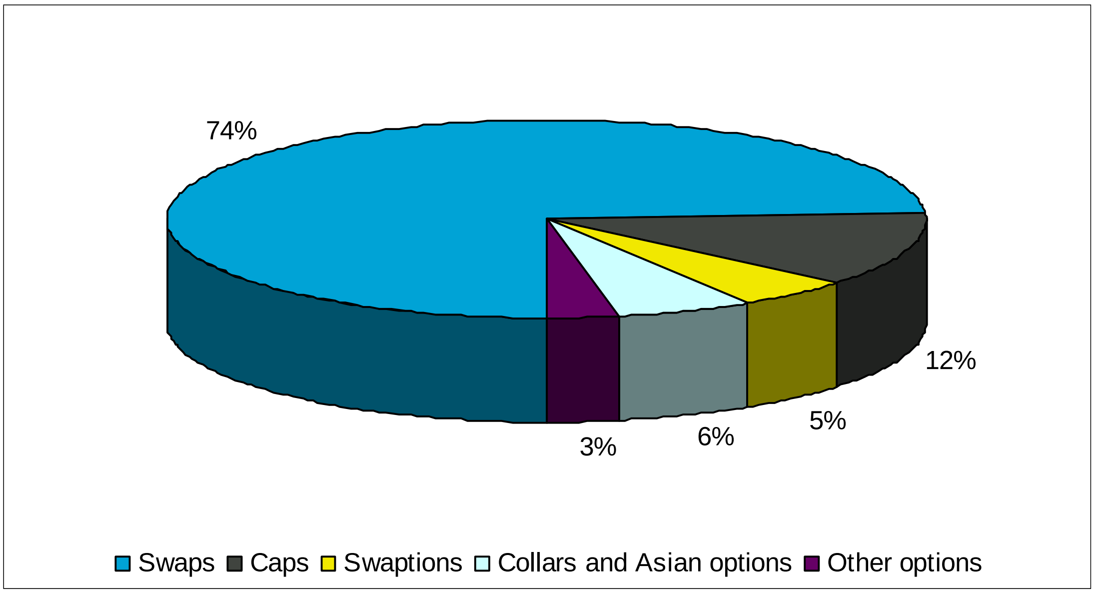
[187] NEMMCO, Australia’s National Electricity Market: Trading Arrangements in the NEM, p. 29.

[188] Ibid.

Figure 7.2
OTC instruments[189]



Source: ERIG.

In regards to derivatives purchased OTC, the most popular type, as listed in the 2007 ERIG Energy Reform report, are swaps. In Figure 7.2 it can be seen that just less than three quarters of all derivatives purchased OTC are swaps, with the next dominant derivative being price caps.

7.2.1.3. Futures

A futures contract is a standardised contract, traded on an exchange, for the purchase or sale of an underlying asset at a future date. In Australia electricity futures are traded on the SFE, with the products traded including base load and peak period futures and options on swap futures.[190]

Each futures contract is highly standardised with set sizes and maturity dates. Whilst this feature reduces the flexibility of futures in comparison to OTC instruments, it enables them to be traded on the SFE. The benefit of exchange-based trading is that they are cleared and settled through a centralised clearing house (SFE Clearing Corporation). In this process the SFE Clearing Corporation imposes margin calls on every party, which allows it to acts as the counterparty to every transaction, thus reducing the credit risk of futures.[191]

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189 ERIG, Energy Reform: The way forward for Australia, 2007, p. 2217.

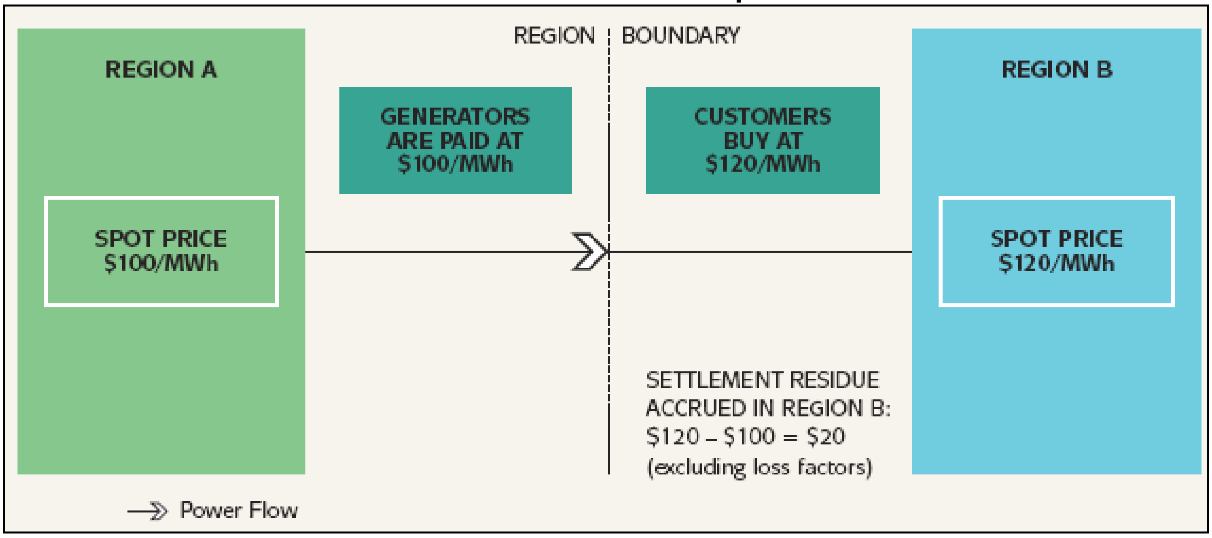
190 A base load future is essential a swap covering the entire day whilst a peak period future covers 7:00am to 10pm on Monday to Friday. For further information on the products available on the SFE refer to http://www.d-cyphatrade.com.au/products/electricity_futures/strip_futures_products

191 NEMMCO, Australia's National Electricity Market: Trading Arrangements in the NEM, p. 30.

7.2.2. Settlement Residue Auction (SRA)

It was previously discussed that the NEM operates across six distinct regions, each of which is linked through one or more interconnectors. Each interconnector has a physical limit as to how much electricity can be transported through it, known as a capacity constraint. When the system linking each region reaches its capacity, a price differential arises whereby the spot price of electricity in one region will differ to that in another. For instance in Figure 7.3, the difference between the value of electricity produced in region A but sold in region B is the SRA for region B. The difference in price between the region where the electricity is sold and the region where it is generated is called the inter-regional settlement residue (IRSR).

Figure 7.3
Settlement residue auction process[192]



Source: NEMMCO.

The significance of a price differential is that where a participant in the NEM has entered into a contract with another party in a different region, they are exposed to the risk that the prices may differ. This is known as the inter-regional price difference risk.

By way of example, suppose that a retailer in Victoria enters into a swap agreement with a generator in New South Wales at a strike price of $50 per MWh, based on Victoria's regional price. If the price of electricity in Victoria increases to $100 per MWh, then the New South Wales generator would pay the Victorian retailer $50 per MWh for the agreed quantity. However, if the New South Wales regional spot price remained low, i.e. $50 per MWh, then the generator would only receive $50 per MWh for its generation, resulting in a loss of $50 per MWh.

In order to encourage inter-regional trade, NEMMCO has made the IRSR available to market participants so that they can manage the inter-regional price difference risk. In making the IRSR for each quarter year available, NEMMCO conducts a quarterly auction in which participants lodge bids for an entitlement (known as units) to any IRSR that accumulated across a designated interconnector. The auction process operates in four tranches with the

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192 Ibid, p. 31.

first tranche occurring one year in advance. In the first tranche 25 per cent of the units are auctioned off, with a further 25 per cent auctioned off at every subsequent quarter.[193]

In addition to the SRA, market participants can manage inter-regional risk through the use of inter-regional swaps and options. These derivatives function in a similar manner to the derivatives described previously, in that they lock the price of electricity for retailers and generators. However, these derivatives cannot be purchased on an exchange like the SFE, rather they can only be purchased OTC.

7.2.3. Government Instruments

In addition to derivatives and the SRA, there are a number of state government instruments which are used to manage market risk.

New South Wales Electricity Tariff Equalisation Fund (ETEF)

In 2001 the New South Wales government initiated the ETEF as a means to smooth wholesale electricity prices for those retailers that are required by law to sell electricity at the regulated tariff established by IPART.

The ETEF operates by forcing retailers to contribute to the fund when spot prices fall below the regulated tariff. When prices exceed the tariff, ETEF pays retailers the difference from the fund. In the event that the ETEF has insufficient funds to compensate retailers, generators are required to 'top-up' the fund until spot prices fall below the regulated tariff level. In 2006 the New South Wales government announced that the ETEF would be phased out by 2010.[194]

Queensland Long-term Energy Procurement (LEP) Arrangement

The LEP scheme is operated by compensating state retailers for the price risk they incur when supplying franchise customers (i.e. those customers who pay a regulated tariff) that is in *excess* of what other retailers are facing. In operating this arrangement, the government benchmarked the cost of supplying electricity to franchise customers and compares this with publicly available data on the cost of supplying electricity to other retail customers.[195] Unlike the ETEF, retailers are still required to manage some price risk through arrangements such as those discussed in Section 7.2.1.

The LEP arrangement was the successor to the Queensland Benchmarking Pricing Agreement (BPA).[196] In light of the recent privatisation of Queensland's retail businesses the LEP scheme has been abandoned.

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193 NEMMCO, National Electricity Market Settlement Auction Rules, p. 9.

194 Review of Regulated Retail Tariffs and Charges for Electricity 2007 to 2010, IPART, July 2006.

195 ERIG, Review of Energy Related Financial Markets: Electricity Trading, 2006, p. 76-77.

196 Under the terms of the BPA, retailers received a payment for supplying franchise customers with electricity and in the event that total revenue exceeded expenses they would pay the State Treasury the difference.

7.2.4. Vertical Integration

One approach to hedge against market risk in the NEM is by combining retailing and generation businesses into one operation, ie, vertical integration. The benefit of such an approach is that it provides the merged entity with a physical hedge against adverse price movements, although it also creates other risks associated with managing generation capacity and load requirements and it does not entirely eliminate price risks.

The growing popularity of vertical integration as a means to manage price and volume risk is evident by the fact that the three major retailers in the NEM increased their share of generation capacity from 8.5 per cent to 14 per cent from 2002 to 2006.[197] In particular energy retailers are directing their investments towards peaking assets which allow them to manage the risk due to peak and/or extreme price events.[198]

7.3. Effectiveness of Market Risk Tools

The effectiveness of any hedging strategy is dependant on having access to a market of sufficient depth so that the price of the hedging instrument is resilient to large orders. Whilst it is important to have an array of hedging tools available to enable participants to satisfy their differing requirements, these tools will be ineffective if there is no depth in the market. It follows that one of the requirements for the operation of the NEM is a liquid electricity financial market.

A liquid market, as defined in the ERIG Review of Energy Related Financial Markets, is one which has *ready and willing buyers and sellers at all times*. As the number of buyers and sellers increases, the depth of the market also increases. In this situation the price of electricity in a deeply liquid market would not be strongly influenced by anything other than extremely large transactions.

Such is the importance of liquidity in electricity financial markets that at least three reviews have been conducted since 2001 examining the issue.[199] In the most recent review, the ERIG Review of Energy Related Financial Markets, it was noted that liquidity in energy markets serves two purposes in that it:

- enables NEM participants to hedge cash flows without owning generation assets; and
- enables price discovery.

7.3.1. Assessment - Hedging

In the most recent assessment of liquidity in electricity financial markets, the general consensus amongst retailers and generators is that the level of liquidity is sufficient for the

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197 ERIG, Review of Energy Related Financial Markets: Electricity Trading, 2006, p. 68.

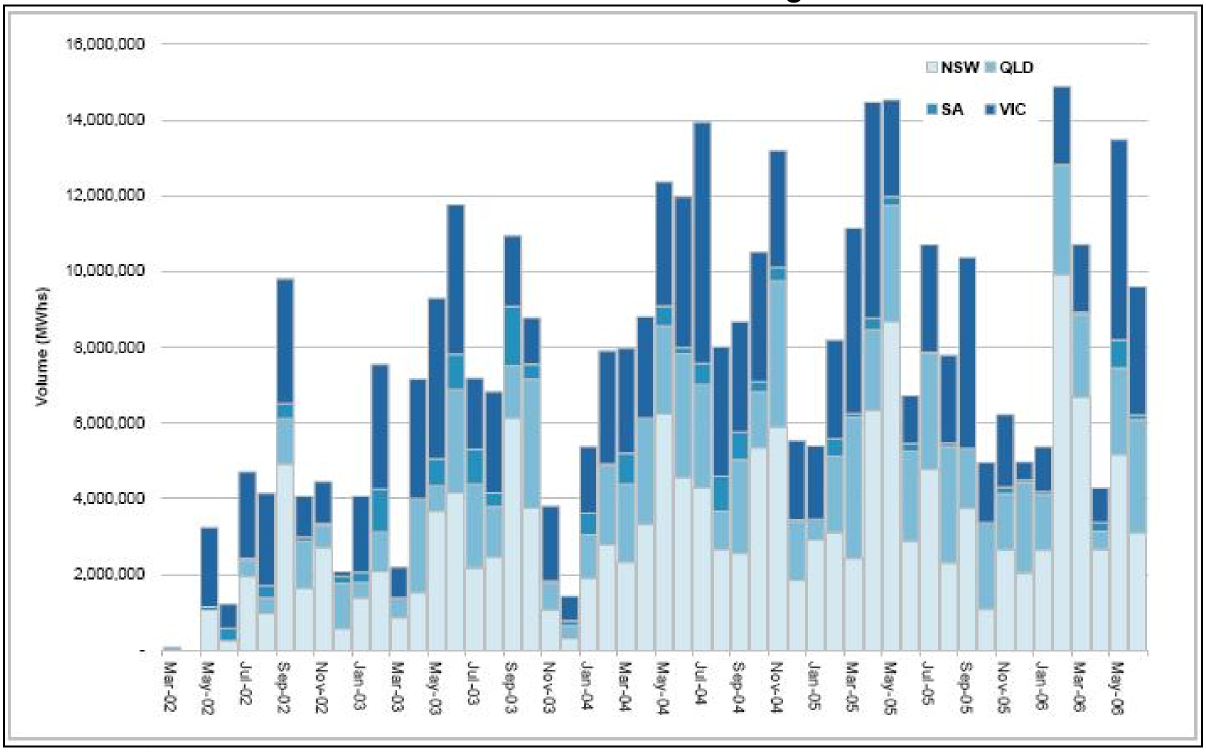
198 We outline in section 5 the extent of vertical integration currently in the NEM.

199 The reviews being; COAG Independent Review of Energy Market Directions, ERIG Review of Energy Related Financial Markets and the Independent Survey of Contract Market Liquidity in the NEM conducted by the National Generators Forum and the Energy Retailers Association of Australia.

management of market risk.[200] In a survey of retailers, generators and intermediaries (commissioned by the National Generators Forum (NGF) and Energy Retailers Association of Australia (ERAA)) 12 participants out of a total of 17 felt that liquidity levels were sufficient. However, most respondents stated that they would like to see more liquidity.

The qualitative results obtained from the NGF and ERAA survey are supported by a time series analysis of trading volumes of derivatives sourced from both brokers and the SFE. As illustrated, the volume of derivative traded through brokers and the SFE have trended upwards since 2002. In particular the popularity of electricity futures has risen dramatically since the relaunch of these instruments in 2002, such that by 2005/06 SFE volumes represented approximately 29 per cent of total NEM demand.[201]

Figure 7.4
Volume of derivatives traded through brokers



Source: NGF and ERAA.

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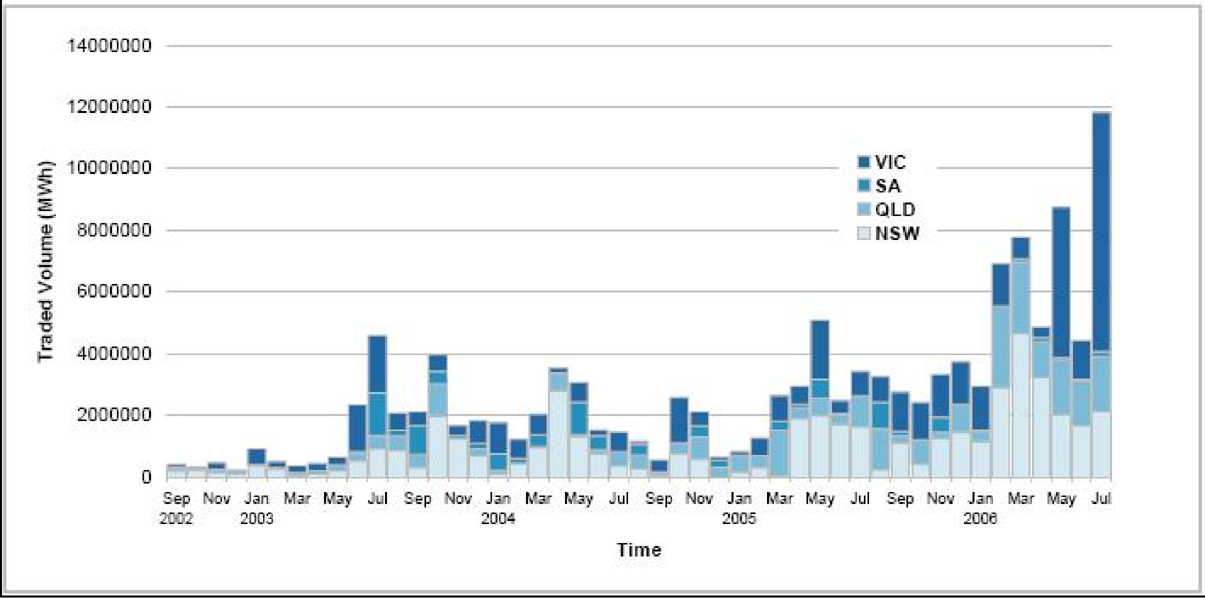
200 PWC, Independent Survey of Contract Market Liquidity in the National Electricity Market, 2006, p. 22.

201 Ibid, p. 13-14.

Figure 7.5
Volume of derivatives traded through SFE



Source: NGF and ERAA.

Figures 7.4 and 7.5 illustrate the volume of derivatives traded for each region within the NEM. In terms of derivatives traded over the counter, New South Wales, Victoria and Queensland all exhibit significant and growing levels of market depth. In contrast, South Australia exhibits very little market depth and in particular the volume of contracts traded has not grown since 2004. This feature is also observable in derivatives traded through the SFE, where South Australia lags the other states in terms of the size and growth of the electricity derivatives market.

In regards to the level of derivatives traded directly between participants, ie, ignoring broker and SFE originated trades, the volume can be estimated through the use of AFMA's surveys of NEM participants.

Figure 7.6 shows the trading volumes of derivatives based on AFMA surveys in addition to trades carried out through brokers. From this data the actual level of direct bilateral trades is calculated.[202] As can be seen, the level of direct bilateral trades has steadily declined over time. In 2005/06 only 73,000,000 MWh of electricity was hedged in this manner, a 55 per cent reduction since 2002/03.

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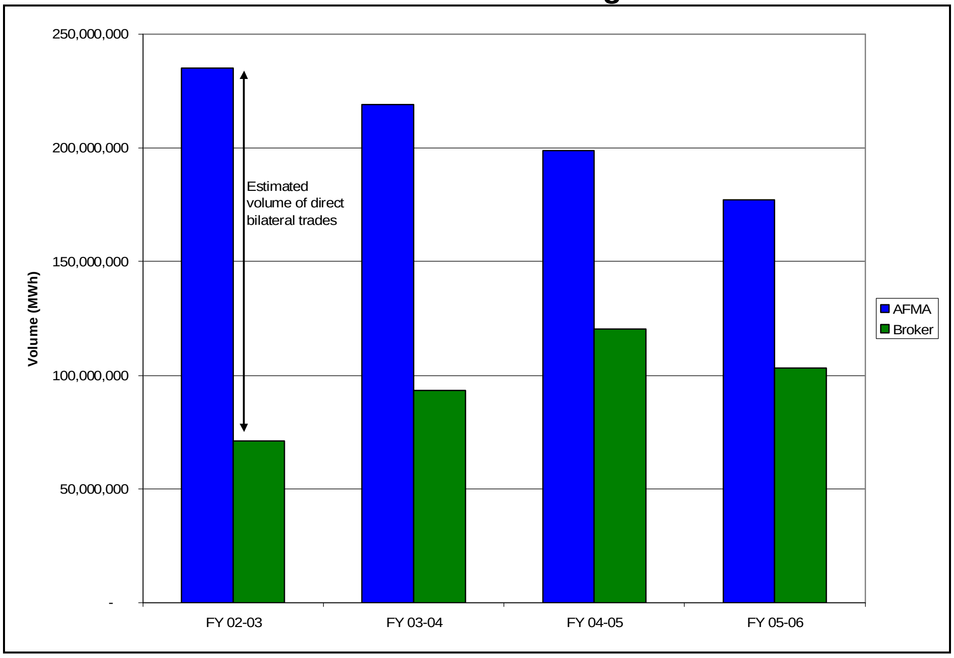
[202] As noted in the NGF & ERAA survey, this technique will understate the true level of direct bilateral trades as not all participants submit responses to the survey.

Figure 7.6
Estimated derivative trading volumes



Source: AFMA.

Table 7.1
Implied direct bilateral trade volumes (TWh)

	2002-03	2003-04	2004-05	2005-06
AFMA	235.0	219.0	198.9	177.1
Broker	71.2	93.3	120.3	103.3
Implied direct bilateral trades	163.8	125.7	78.6	73.8

Source: AFMA.

In light of the growing size of the derivatives market in the NEM, it is interesting to note the extent to which NEM demand is being hedged through financial derivatives traded through brokers and the SFE.

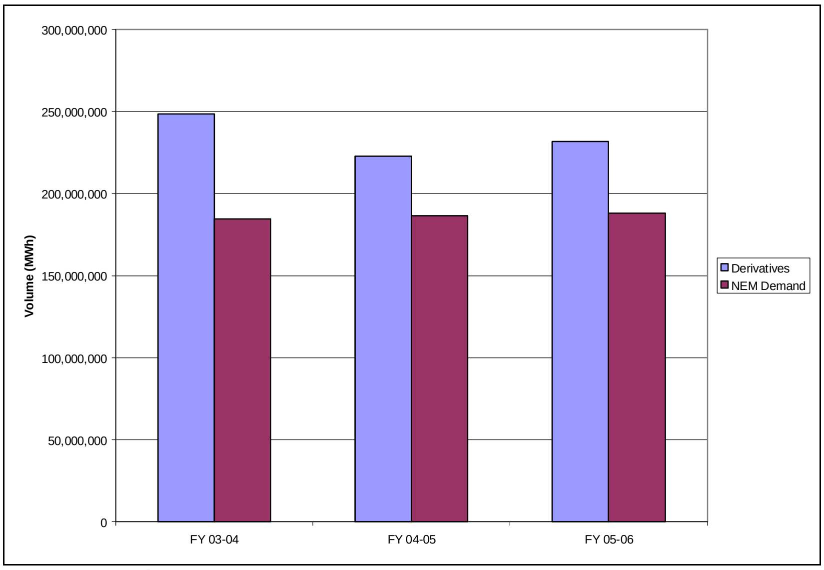
Table 7.2
NEM Demand vs trading volume[203]

	2003/04	2004/05	2005/06
SFE & Broker volume (TWh)	122.8	144.1	157.9
Total NEM demand (TWh)	184.4	186.7	187.9
NSW NEM demand	73.7	74.4	75.1
ETEF as % NSW NEM demand	30%	26%	24%
ETEF demand (TWh)	22.1	19.4	18.0
SFE & Broker volume % of Total NEM demand	67%	77%	84%

Source: NGF and ERAA.

The table above indicates that over the last three years a greater proportion of demand is being hedged through OTC and SFE derivatives. From 2003/04 to 2005/06 the proportion of demand in the NEM that is hedged using derivatives increased from 67 per cent to 84 per cent. In fact if the quantity of direct bilateral trades were included, then it can be seen that the entire NEM demand is hedged as per Figure 7.6.[204]

Figure 7.7
NEM demand and contracted volumes, 2003-04 to 2005-06



Source: NGF and ERAA.

One feature of interest in Table 7.2 is the size of the ETEF as a proportion of New South Wales NEM demand. Since its introduction, the ETEF has drawn criticism from various market participants and stakeholders for reducing the liquidity in financial markets. In 2002 the Minister for Industry, Tourism and Resources described the ETEF as "the single most

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203 Ibid.

204 PWC, Independent Survey of Contract Market Liquidity in the National Electricity Market, 2006, p. 14.

distortionary mechanism for the wider market".[205] The issue with ETEF in this context is that those participants using the fund could be using financial contracts instead to manage their wholesale market risk. The New South Wales government plans to phase out the ETEF from 2008, with complete abolition by 2010.[206] The expected result of this change in policy is that the contract market in New South Wales and the NEM will expand.

Similarly the Queensland government's initiative to smooth price fluctuations has also had the effect of reducing liquidity in electricity financial markets.[207] With the privatisation of the retailing businesses in that state, the LEP arrangement has now been abandoned.

Whilst it is clear that electricity financial markets are expanding the ERIG review concluded that they still exhibit a number of shortcomings. One of the principal shortcomings cited is that liquidity is not uniform, with financial markets lacking depth when hedging risk in excess of three years.[208] This feature is evident in Figure 7.8, which shows the number of future contracts open as at 25 September 2006.[209] The figure illustrates that futures trading is limited to the first 2-3 years with very few contracts open beyond that point in time.

Figure 7.8
Volume of futures contract open at 25 Sep 2006

Source: ERIG.

A further issue raised in the ERIG review is the growing trend towards consolidation in the NEM, in particular the rise of vertically integrated participants. The opinion amongst market participants is divided as to whether this trend has the effect of reducing liquidity.[210] On the one hand it is argued that the presence of vertically integrated companies provides a natural hedge, thereby reducing the need to use financial hedges such as derivatives, which in turn

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205 Macfarlane, I., Address to the Sydney Institute, 2002.

206 ERIG, Review of Energy Related Financial Markets: Electricity Trading, 2006, p. 76-77.

207 COAG, Towards a Truly National and Efficient Energy Market, 2002, p. 159.

208 PWC, Independent Survey of Contract Market Liquidity in the National Electricity Market, 2006, p. 23.

209 ERIG, Energy Reform: The way forward for Australia, 2007, p. 219.

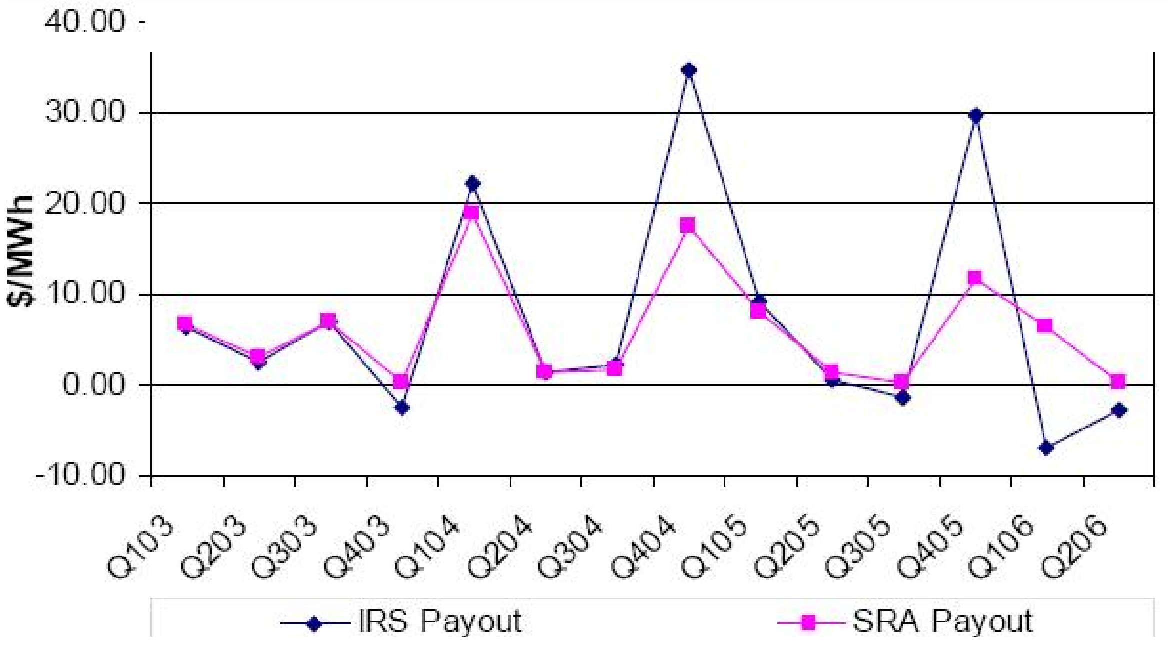
210 ERIG, Energy Reform: The way forward for Australia, 2007, p. 221.

reduces market liquidity. Supporters of vertical integration, however, point out that the depth of financial markets has increased during a period where vertical integration has been prevalent.[211]

In the NGF and ERAA survey, similar conflicting results were observed in regards to the impact of vertical integration on liquidity. The acquisition of Southern Hydro by AGL was seen by a number of respondents to reduce liquidity, as Southern Hydro was an active player in the derivatives market. The acquisition of SPI Australia's merchant business by CLP Power had the opposite effect with the merged entity now an active participant in financial markets.[212]

On the issue of the effectiveness of hedging inter-regional risk, 15 out of the 17 respondents in the NGF and ERAA survey felt that they could adequately manage the risk given the available instruments. The application of the SRA as a risk management tool was however slightly more subjective, with some respondents regarding the lack of firmness in SRA's as holding back inter-regional trade.[213]

Figure 7.9
SRA Payout versus Inter-regional Swap Payout: Victoria to New South Wales



Source: Hydro Tasmania.

Figure 7.9 illustrates the payout from an inter-regional swap (IRS payout) against the payout from SRA units across the VIC to New South Wales interconnector.[214] Given that the swap

[211] PWC, Independent Survey of Contract Market Liquidity in the National Electricity Market, 2006, p. 26.

[212] Ibid.

[213] Firmness refers to the fact that the payout from the SRA depends on the IRSR that accumulates for a specific NEM interconnector. Hence given that the level of interconnector flows vary significantly over time, SRA's aren't regarded as being firm in comparison to derivatives sucha s swaps which have fixed volumes associated with them. For more information on the role of SRA's refer to ERIG's Energy Reform: The way forward for Australia, 2007 p. 50-62.

[214] The VIC – NSW interconnector is actually represented by the VIC – SNOWY – NSW interconnector.

is a firm instrument, by contrasting the payout from the SRA against the swap, it is possible to examine the effectiveness of the SRA in hedging inter-regional risk.

As can be seen, for the most part the payout from both instruments is nearly identical. At certain times, however, ie, Q404 and Q405, the payout from the SRA is less than the swap, reflecting transmission constraints and other physical factors that affect interconnector flows and hence the SRA payout. In these situations the SRA is an imperfect instrument to hedge inter-regional risk. Where the swap payout is negative, it is a reflection that the electricity is flowing in a different direction than that intended in the inter-regional swap.[215]

7.3.2. Assessment - Price Discovery

One of the key roles of the electricity financial market is that it can act as a medium for price discovery. With 50 to 70 per cent of all trades being direct and bi-lateral,[216] market participants have limited access to pricing information. Without access to this information participants, and in particular new entrants, may face some difficulty in assessing and pricing the cost of hedging their exposure to market risk.

In light of this difficulty, the futures market is playing an increasingly important role for participants in assessing the cost of hedging. It was generally accepted in the NGF and ERAA survey that transparency though futures and brokers play an important role in facilitating trading and assessing risk. Interestingly, the absence of price information arising due to the dominance of direct bilateral trades was not seen as an impediment to price discovery.[217]

One issue of concern noted in the ERIG review was that price discovery through the futures market was very difficult for periods exceeding three years. Given the lack of depth in the market, represented by very few open contracts extending beyond three years, market participants must use other sources of information to examine future price trends. One consequence of this problem is that it is difficult to evaluate long term hedging costs associated with decisions such as investing in generation assets.

7.4. Managing Settlement Risk and Credit Risk

7.4.1. Spot Market

In order to manage settlement and credit risk in the spot market, NEMMCO has established a prudential framework which imposes obligations on market participants. These obligations involve four key areas; credit criteria, credit support, a maximum credit limit and a trading limit.

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215 ERIG, Review of Energy Related Financial Markets: Electricity Trading, 2006, p. 53-60.

216 Ibid, p. 21.

217 Ibid, p. 24

7.4.1.1. Credit Criteria

All registered entities participating in the NEM are required to meet certain criteria under the National Electricity Code. The first requirement is that the entity must be under supervision by either the Australian Prudential Regulation Authority (APRA) or a relevant State or Territory body. [218]

Additionally each entity is required to hold an acceptable credit rating. In regards to this matter an acceptable credit rating is defined as being higher than A-1 under the Standard and Poor's index or higher than Moodys P-1.

On top of these requirements, each entity must provide credit support to NEMMCO. Where an entity cannot provide such support on their own right then they must obtain this from an entity that satisfies the required credit criteria.[219]

7.4.1.2. Credit Support

Credit support relates to the requirement for each entity to pay NEMMCO unconditionally on demand and up to a nominated limit. This requirement is satisfied by providing NEMMCO with certain instruments issued by an entity that meets the acceptable credit criteria. The entity from which the instruments originate cannot be a participant in the NEM.

Of the types of instruments that can be provided as credit support, the most common is a bank guarantee. Other forms of credit support include security deposits in the form of cash lodged with NEMMCO.

In addition to requiring credit support from participants in the NEM, NEMMCO can issue call notices to market participants. A call notice is a demand for the provision of additional credit support and must be met by 11am on the next business day. Failure to do so can lead to a default notice and at worst market suspension.[220]

7.4.1.3. Maximum Credit Limit

In its role as the market operator, NEMMCO provides financial settlement services such as billing and collecting funds for each trade in the market. In carrying out this role there exists the risk that there may be a shortfall in funds collected.

NEMMCO minimises this risk by imposing on each participant a maximum credit limit (MCL). The MCL represents the worst-case estimate of NEMMCO's exposure to any financial participant over a 42-day trading period. From the MCL, NEMMCO is able to calculate the acceptable amount of collateral (credit support) that each participant is required to lodge.

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218 NEMMCO, Australia's National Electricity Market: Trading Arrangements in the NEM, p. 14

219 For further information on credit criteria refer to the NEMMCO paper Australia's National Electricity Market: Trading Arrangements in the NEM.

220 In the event of a market suspension the jurisdiction in which the entity operated may nominate a retailer of last resort to assume responsibilities for delivering electricity supply.

7.4.1.4. Trading Limit

The establishment of a trading limit is designed to provide NEMMCO with an early warning that the MCL may be breached. The trading limit is set at 84 per cent of a participant's MCL, with the 16 per cent difference providing NEMMCO with sufficient notice to issue a call requesting additional credit support.

7.4.2. Forward Market

One of the fundamental differences between the two forms of derivatives discussed in section 7.2 is that they can be either OTC or exchange-traded. The form that the derivative takes has significant implications on the level of credit and settlement risk of the contract.

For OTC derivatives, the management of credit risk is the responsibility of each market participant. With every forward contract, there is a certain degree of risk that the counterparty may not be able to pay for reasons such as changes in the underlying electricity price or to their credit status. It is therefore the usual practice for each market participant to establish credit limits with counterparties in order to minimise their exposure to default. The ERIG review concluded that there is little evidence that credit default risk is priced into the contract market.[221]

As is briefly discussed in section 7.1, the exchange-traded derivatives market contains a mechanism to manage credit risk. Through its role as the clearing house, the SFE Clearing Corporation acts as the counterparty to every trade and therefore is liable to perform against all contracts. This eliminates the need for participants to assess the credit level of potential counterparties, which in turn enhances the attractiveness of the SFE and thus promotes liquidity.[222]

221 ERIG, Review of Energy Related Financial Markets: Electricity Trading, 2006, p. 81.

222 For further information on credit risk in the spot and forward markets refer to the 2006 ERIG Review of Energy Related Financial Markets.

8. Recent reviews and policy decisions

8.1. Recent reviews

The operation of the wholesale electricity market has undergone a number of reviews since its inception in 1998. The objective of these reviews has been to ensure that the market is operating in a manner consistent with market efficiency principles, and delivering appropriate incentives for new generation investment. The most notable of these reviews include:

§ an independent review chaired by Warwick R. Parer, that was commissioned by the COAG to examine the strategic direction for energy market reform including the governance and regulatory reforms required across both the gas and electricity markets (Parer Review);

§ a review by the Productivity Commission of National Competition Policy Reforms, which included a consideration of the reforms as they related to the energy sector;

§ a further review by the Productivity Commission of the potential benefits of the National Reform Agenda, also including a consideration of the benefits as they related to the electricity sector; and

§ a review of certain elements of the operation of the energy sector by the Energy Reform Implementation Group (ERIG), which was established by the COAG.

The Parer Review was undertaken at a time where there was some criticism about the competition reforms, as this process of reform had resulted in significant changes to the structure of the electricity and gas markets in Australia. In particular, some commentators blamed the reforms for increases in energy prices.[223] The key findings from the review as relevant to the operation of the wholesale market included the finding that:[224]

§ there was insufficient generator competition for the gross pool system to work as intended; and

§ there was a lack of liquidity in the financial contracts market, due in large part to regulatory uncertainty.

To address these market deficiencies it was recommended that changes be made to the regulatory structure, including the Ministerial Council on Energy (MCE) subsuming the responsibilities of the previous NEM Ministers Forum to direct energy policy, and the creation of a national energy regulator to replace the existing jurisdictional based regulators. To address market operation concerns, the recommendations focused on the removal of the ETEF and Benchmark Pricing Arrangements in New South Wales and Queensland respectively; disaggregating generators in New South Wales to improve competition; and the development of specific criteria by the Australian Competition and Consumer Commission (ACCC) to apply when considering mergers between generators.

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223 Parer, Warwick R, Towards a Truly National and Efficient Energy Market, 20 December 2002, p.7.

224 Ibid, p.9.

Many of the reforms in the energy market that are currently being implemented stem from these original Parer Review recommendations.

Following the Parer Review, the MCE agreed to progress a range of reforms related to market governance, economic regulation, electricity transmission development and planning, and energy user participation, amongst others.[225] This new energy market reform program was endorsed by COAG in 2004 and included an agreement to establish the AER and the AEMC.

As part of the Productivity Commission's review of National Competition Policy reforms, a number of gaps were identified in the energy reform program. These included:[226]

- the need to strengthen competition in the generation sector, particularly in those regions dominated by government-owned generators; and
- the need to examine the competition laws as they apply to potential mergers between transmission and generation businesses.

In general, the Productivity Commission indicated that existing competition law was sufficient to address concerns surrounding potential mergers between generators.

The most recent review of the energy market reforms was undertaken by the ERIG. The key findings of this review were that:[227]

- increasing contestability in generation, further disaggregation, privatisations and improving competitive neutrality provisions would be required to improve the operation of the electricity market;
- the financial trading mechanisms particularly those supporting interstate trade should be improved along with the firmness of inter-regional trading rights, and by contracting relevant generators to support inter-regional electricity flows; and
- the settlement arrangements between the spot and contract markets should be improved to reduce the duplication of credit requirements and to reduce barriers to entry.

Improving competition amongst the government-owned electricity businesses was another key finding with the review concluding that:[228]

> *Disaggregation of significant retail and generation portfolios, followed by privatisation, is the most effective solution to most of these problems and would increase the overall efficiency of Australia's energy sectors.*

In response to the ERIG report, the COAG agreed that the AEMC and NEMMCO should investigate ways to improve the integration of the spot and contract markets and improve prudential requirements in order to enhance the efficient operation of the wholesale

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[225] Including relating to the natural gas market and addressing greenhouse emissions from the energy sector (MCE report to COAG, 11 December 2003, p.4).

[226] PC, Review of National Competition Policy Arrangements, 28 February 2005, p.185.

[227] ERIG, Energy Reform: the way forward for Australia, January 2007, p.1.

[228] Ibid, p.8.

market.[229] There was no response to ERIG's findings relating to the need to improve contestability in the operation of the market.

In essence, future reforms to the operation of the wholesale electricity market are likely to build on earlier reforms that have sought to improve competition in the wholesale market, and the efficiency of the trading mechanisms, particularly as they relate to access to financial risk instruments.

8.1.1. Owen Inquiry

In May 2007 the New South Wales Government established an inquiry (known as the Owen Inquiry) into the state's supply of electricity. The purpose of the inquiry was to establish the need for and timing of investment in additional base load generation, and to determine how this could best be achieved in light of available technologies and ensuring that the state maintain its AAA credit rating.

The Owen Inquiry, which was released in September 2007, found that there was a need for further investment in baseload generation by 2013-14. Having investigated recent power generation developments in Australia the inquiry observed that new investment can take up to six years before delivering additional capacity and thus preparation for new baseload supply needs to begin immediately. The inquiry also noted that the cost of supplying additional capacity could cost up to $15 billion. Given the magnitude of these costs it was noted that the most efficient means of providing the baseload capacity would involve transferring the retail and generation interests into the private sector. Specifically, the inquiry recommended that the New South Wales Government:[230]

- divest the retail components of EnergyAustralia, Integral Energy and Country Energy;
- divest or lease the generation businesses of Macquarie Generation, Delta Electricity and Earing Electricity; and
- encourage the Commonwealth Government to bring forward the timetable for the national emissions trading scheme.

In December 2007 the New South Wales Government accepted the recommendations of the Owen inquiry and announced plans to privatise the retail businesses and lease the generation assets.[231]

8.2. Policy Decisions

8.2.1. Mandatory Renewable Energy Target

In April 2001 the Australian Government's introduced the MRET. The MRET places a legal obligation on wholesale purchasers of electricity to proportionately contribute towards the generation of an additional 9,500 GWh of renewable energy annually by 2010. This liability

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[229] COAG Communique, 13 April 2007.

[230] Owen Inquiry into Electricity Supply in NSW, September 2007.

[231] Premier of New South Wales, NSW Government acts to secure State's energy supply, 10 December 2007.

is imposed by requiring purchasers of electricity (known as liable entities, i.e. retailers) to purchase a set percentage of electricity from renewable sources.

In order to deliver the MRET objectives, generators are awarded Renewable Energy Certificates (RECs) when they generate electricity from renewable sources above and beyond their 1997 baseline.[232] Conversely liable entities are deemed to have a REC liability for every MW/h of electricity supplied. This liability is calculated based on the Office of Renewable Energy Regulator's renewable power percentage (RPP), as displayed in the able below.

Table 8.1
Renewable Power Percentages

Year	Renewable Power Percentage (%)
2001	0.24
2002	0.62
2003	0.88
2004	1.25
2005	1.64
2006	2.17
2007	2.70
2008	3.14

In order to satisfy the MRET, liable entities are required to surrender a certain number of RECs every year.[233] This process is facilitated through the trading of RECs between generators and liable entities through either the REC market or directly with one another. If liable entities are unable to meet the REC requirement they are then charged $40/MWh.

For instance if a retailer purchased 1 GWh of electricity in 2008, they would be required to surrender 31,400 RECs (on the basis that the renewable power target was 3.14%). If, however, the retailer only held 20,000 RECs they would be fined $456,000.

At the COAG meeting in December 2007, the Commonwealth and states agreed to bring the existing MRET and the various state-based targets into a single, expanded national MRET scheme by early 2009. The Commonwealth Government committed to increasing the MRET from 9,500 GWh to 45,000 GWh in 2020 to ensure that the goal of a 20 per cent share for renewable energy in Australia's electricity supply is met by 2020.

The expanded MRET measure is to be phased out between 2020 and 2030 as emissions trading matures and prices become sufficient to ensure that an MRET is no longer required to drive deployment of renewable generation technologies.

[232] Small generating units and solar water heaters can be deemed eligible for a fixed number of RECs

[233] RECs must be surrendered for the previous years liability between 1 January and 14 February every year. Office of the Renewable Energy Regulator website, http://www.orer.gov.au/recs/index.html.

The breakdown of policy decisions that led to the 20% by 2020 goal are illustrated in the table below:

Table 8.2
Renewable energy policy decisions

Scheme	Contribution (%)
Pre-existing renewable energy (pre-1997)	5.2
Howard Government MRET	3.1
Howard Government clean energy target	0.0
State governments clean energy targets (existing/proposed)	6.7
Federal Government's substantial increase in MRET	5.0
Total proportion of renewable energy by 2020	**20.0**

8.2.2. Government Funds

To support the development of renewable energy based electricity generation, the Commonwealth Government has created a range of initiatives and funds. The key initiative of the government's platform is the *Low Emissions Technology Demonstration Fund*.

This fund, which will operate until 2019/2020, is designed to encourage private sector investment in low emissions technologies with the stated objective of leveraging at least $1 billion in private sector investment. The principal method by which this objective will be achieved is through the allocation of grants totaling $500 million and the requirement that the private sector must match every $1 of public funding with $2 of private funding.[234]

Examples of the Low Emissions Technology Demonstration Fund at work include:[235]

- $420 million 154 MW solar generation plant in Melbourne[236], which is expected to be the biggest photovoltaic plant in the world. The funding for this project includes $125 million from both state and federal governments and the remainder from the private sector; and
- $445 million 100 MW coal seam methane plant in Queensland[237]. This plant, unlike other natural gas fired plants in Australia, will capture and store one third of CO2 emissions (100,000 tonnes) in deep coal beds. This project estimates that by 2030 5 per cent of Australia's CO_2 emissions could be stored in such coal beds.

In addition to the Low Emissions Technology Demonstration Fund, small funds have been established by AusIndustry to promote the use of renewable energies. These include:

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234 Australian Government, Low Emissions Technology Demonstration Fund: Customer Information Guide, p. 1.

235 Ausindustry website, http://www.ausindustry.gov.au/library/LETDF_grantoffers_march0720070327095527.pdf.

236 This is a joint venture between Solar Systems and TRUenergy.

237 This initiative is being run by Santos Limited. Santos website, http://www.santos.com.au/library/Santos_investing_in_Qld_future.pdf.

- Renewable energy equity fund – this fund provides venture capital and managerial advice to small companies to assist them in commercialising their research and development in renewable energies; and
- Renewable energy development initiative – this is a competitive grants program that supports renewable energy innovation and commercialisation. Grants of between $50,000 and $5 million are offered on the basis that the funding is used to derive sustainable energy from the sun, wind or geothermal sources.

9. Issues for retail competition

In this report we have provided an overview of the structure and operation of the wholesale national electricity market across the eastern seaboard of Australia. Our focus has been to provide a snapshot of the market structure within each of the NEM regions, by identifying generator capacity and ownership, electricity supply and retailer customer share. In addition, we have outlined the tools used to manage the risks associated with providing retail services, particularly managing wholesale price risks.

In summary the NEM is made up of five regions based on state boundaries where:

§ transmission and distribution services are provided by an interconnected common carriage network of high and low voltage lines;

§ coal-fired generators are the main source of electricity output and capacity, providing approximately 86 per cent of total electricity output in the market; and

§ generation capacity (to meet increasing demand, particularly for peak load) has been increasing through investment in peaking gas-fired plants, and there is likely to be a need for additional generation capacity investment in the near future.

While for presentational convenience we have presented information in this report on generator capacity and output by NEM region, any assessment of the competitiveness of the wholesale market requires an analysis of the nature and extent of competitive intensity by generators across the NEM regions.

Ongoing development of the NEM and particularly the market operating rules and regulatory structures are also likely to influence the operation of the wholesale market and behaviour of market participants, with subsequent implications for retail competition. The likely impact of these changes should also be taken into account in an assessment of the effectiveness of retail competition.

Finally, there are emerging circumstances arising from the current state of the market that may influence retail competition. Some of these include:

§ proposals for reform to the operation of the wholesale market (the ERIG reform proposals), that have as their objective the increasing of contestability amongst generators;

§ increasing attention to carbon emissions, leading to a greater likelihood that Australia will consider mechanisms to limit carbon emissions;

§ the decision by the New South Wales government to abolish the ETEF, will result in New South Wales retailers increasing demand for alternative risk management tools such as derivative contracts; and

§ a tendency by some private retailers to invest directly in generation capacity to provide a natural hedge against wholesale price increases.

In the remainder of this chapter we focus on wholesale market competition, the sources of price variations and implications for retail competition.

9.1. Observations on the extent of wholesale competition

As we have outlined in greater detail for each NEM region in section 3, there are a relatively large number of generation companies competing to supply electricity into the market. For example, 14 generation companies each control in excess of 2 per cent of total NEM generation capacity, and supplied over 86 per cent of total electricity to the market in 2005/06.

As outlined above, an analysis of wholesale market competition requires a consideration of a number of factors including:

- the degree of substitutability between generation in each region, which requires a consideration of losses affecting generator competitiveness between regions and the frequency of interconnector constraints;
- the portfolio of generation assets owned by a single generation company, since this can affect its incentive and ability to influence market prices; and
- the relative market shares for generators.

The relative market share of a generator, however, will not necessarily be indicative of competition in the market. It is possible for a generator with relatively low market share to influence wholesale prices, by controlling generation assets within critical segments of the price stack. All of the above factors should therefore be considered as part of an assessment of competition in the wholesale market, with subsequent implications for retail competition.

Turning to the relative market shares for generators in New South Wales, Queensland and Tasmania, the majority of each region's electricity is supplied by government owned generators. In these jurisdictions, each business has a large share of total generation capacity and output both within their respective NEM region and the entire NEM - Table 9.1.

For the remaining NEM regions, private provision of generation has led to a larger number of generation companies. This has meant that the total capacity share and proportion of output for any one generator tends to be lower than generators in states with a majority of government owned generators. For example, in Victoria five generators each have capacity shares in excess of 10 per cent, with the largest supplying 31 per cent and the smallest 0.9 per cent of Victorian electricity output in 2005/06.

In addition, the market share of the larger generators has been steadily eroded through ongoing investment in alternative energy sources. We anticipate that this will continue, particularly with increased concern about carbon emissions and the potential introduction of a national carbon trading scheme. While a significant carbon tax would be required to price existing coal-fired power plants entirely out of the market, support for generation capacity that has lower carbon emissions, where these investments are not made by existing generators, will impact on market shares by existing generators in the wholesale market.

Table 9.1
NEM and regional capacity and supply shares as at 30 June 2006, by generator

	Share of NEM region capacity (%)	Share of NEM capacity (%)	Share of NEM region supplied electricity 05/06 (%)	Share of NEM supplied electricity 05/06 (%)
New South Wales				
- Macquarie Generation	36.7	10.8	34.8	13.9
- Delta Electricity	33.1	9.8	28.9	11.5
- Eraring Energy	23.3	6.9	17.9	7.1
Snowy Hydro	100.0	8.5	100.0	2.7
Queensland				
- CS Energy	24.2	6.5	25.6	7.2
- Tarong Energy	20.3	5.4	26.2	7.4
- Stanwell Corporation	13.7	3.7	18.7	5.3
South Australia				
- TRUenergy	32.0	3.0	19.3	1.2
- International Power	22.1	2.0	12.5	0.8
Tasmania				
- Hydro Tasmania	98.4	6.0	97.2	4.6
Victoria				
- Loy Yang Power	22.5	4.9	31.0	8.4
- Hazelwood Power Partnership	17.0	3.7	20.5	5.6
- TRUenergy	15.7	3.4	20.4	5.6
- IPM Eagle	10.6	2.3	15.9	4.3
- Ecogen Energy	10.2	2.2	0.9	0.2

9.2. Sources of wholesale market price variations

As we outline in section 2.2, wholesale electricity market prices have a number of features. First, average electricity prices vary between each of the regions, reflecting differences in each region’s demand and supply characteristics, the physical nature of the connecting infrastructure, electricity losses within the network, and differences in ramp rates between generators amongst other factors. Second, wholesale price volatility also differs between the regions, due to these same characteristics. Third, wholesale prices on average have been rising, reflecting reductions in the proportion of reserve capacity present in the market, higher coal prices due to increased export demand, and drought conditions.

To manage price volatility, there has been an increase in the volume of financial hedging arrangements such as over-the-counter and broker contracts. This allows retailers to lock-in their wholesale costs for periods of up to three years. Beyond three years, contract liquidity reduces, in part due to the uncertainty about wholesale prices after that period.

Concern has been expressed that the liquidity of contract or derivative instruments based on the wholesale electricity market may be affected by increasing vertical integration between some electricity retailers and generators. In practice however, the relationship between vertical integration and contract market liquidity is unlikely to be so straightforward. Some factors to consider in relation to this issue are:

- a retailer is unlikely to operate its own generator out of the merit order, ie, if it would be cheaper to purchase electricity on the spot market, thereby creating some incentive to manage spot market price volatility;
- it is extremely unlikely that a retailer's load profile will precisely match its generation portfolio, optimally dispatched, thereby necessitating the use of derivative instruments to manage wholesale market risks arising from mismatches in its balance between load and in-the-merit-order generation; and
- a natural hedge does not eliminate all price risks, in part because physical risks associated with not being able to generate electricity (such as generator or transmission outages) when required can still arise.

ERIG observes that the incidence of price spikes within the market has been increasing over recent years. It implies that this is a problem within the market, such that interventions may be required to 'solve' this problem. In our view however, the simple observation that the numbers of price spikes are increasing is not itself evidence of a problem. Rather, it may well be a simple consequence of the market indicating the need for new generation investment.

The price increases observed in the wholesale market have been driven particularly by a number of generators having to restrict output due to a lack of cooling water to operate their plants. These price rises represent the actual out-workings of the wholesale market as demand and supply are equated for each dispatch interval. We would anticipate that the current high prices will result in some proposed generation projects being accelerated.

These developments on the supply side highlight a wider question about the relationship between wholesale prices, price volatility risk management and retail prices. In principle, hedging arrangements allow retailers to manage price volatility risks. However, where there are sudden changes in input prices, these can be expected to be passed through to customers in the form of higher (or lower) prices. For example, when airlines were faced with large increases in the price of airline fuel, they imposed an additional levy on all tickets. Any limitation on electricity retailers from increasing retail charges in response to higher wholesale costs is likely to have a detrimental effect on competition.

When considering the effectiveness of retail competition it is therefore important to consider the scope for new entrants not only to manage price volatility but also to respond to structural price changes.

9.3. Implications for retail electricity competition

Effective retail competition requires electricity retailers, and particularly new entrants, to have access to wholesale electricity markets and subsequent transmission and distribution services, to allow them to manage retail customer demand. Even where retailers own interests in generation, the nature of the wholesale market and the operation of the electricity system as a network mean that a retailer's load may often not be coincident with its own generation. The wholesale electricity market provides retailers the opportunity to manage demand and supply to meet customers' needs.

The key role of a retailer is therefore to manage the financial and physical risks that arise in supplying the retail market at predetermined fixed prices. Effective retail competition therefore requires retailers to be able to:

- access wholesale electricity supplies, which is achieved through access to the NEM spot market allowing retailers to purchase electricity when required to meet customer needs, and also manage demand variations;
- access hedging instruments to provide an opportunity to manage price volatility risks in the NEM, as required, although there is debate about whether the hedging market and spot market are indeed separate 'markets' in competition terms; and
- flexibility to manage exogenous shocks, such as those arising from significant wholesale electricity cost increases – as in the example of airline fuel levies.

As indicated above, in competition terms it is open to debate whether the hedging market and electricity spot market are sufficiently separate such that any reduction in liquidity in the hedging market (say, arising from vertical integration) is a potential impediment to competitive entry in the electricity retail market. Some factors to consider include:

- the spot market is, by definition, a substitute for the hedging market, since it is always possible for a retailer to settle its requirements exclusively by reference to the spot market if there are insufficient hedging products available;
- in theory, the price of a hedge should equal the expected value of the future spot price plus the cost/value of any financial risks transferred, such that hedging amounts to a form of insurance that allows both generators and retailers to improve the management of cash flows;
- there are transactions costs associated with hedging, such that it is not itself a costless exercise;
- hedging is not itself a risk free process since the cost usually means that retailers do not hedge their full requirements, and in any case it is necessary to decide how much of a retailer's expected load to hedge.

In our view, these complicating factors are important considerations in any assessment of the implications of hedge market liquidity and vertical integration on competition in the retail market.

In addition, it is also relevant when considering the effectiveness of retail competition to examine:

- the effectiveness of wholesale market competition, since this affects the expected cost of wholesale electricity supply to new entrant retailers, particularly in the presence of increasing vertical integration between generators and retailers;

- the effectiveness of the market in delivering new generation investment when warranted by changing demand and supply conditions; and
- the ability of retailers to contract across region boundaries, which impacts on the number of generators a retailer in a particular NEM region has access to when seeking supply contracts.

To consider the effectiveness of wholesale market competition it would be necessary to examine the market structure, conduct and performance. To examine the market structure one needs to consider:

- the number as well as the relative capacity, output and cost structure of generators;
- wholesale electricity supply by generator, fuel source and location within the network (to allow for a consideration of inter and intra regional constraints);
- the history of exit and entry into the generation market within each NEM region;
- the portfolio of assets owned by each generator, its contribution to the wholesale market bid stack and the range of outputs over which an individual portfolio has price-setting plant; and
- the substitutability of the spot and hedging markets, and subsequent implications for access to risk hedging products.

Having considered the wholesale market structure in each of the NEM regions, a number of observations can be made including that:

- price divergences between regions, beyond those explained by losses are likely to be a signal of:
  - a potential need for further interconnection capacity investment; and/or
  - a need to ensure that there are no impediments to transmission businesses responding to these signals;
- wholesale price rises are the principal signal of electricity supply scarcity relative to demand;
- carbon emissions schemes and the MRET scheme will become an increasingly important driver of costs in the wholesale electricity market, enhancing the attractiveness of investment in renewable and gas-fired forms of generation and reducing the relative share of existing coal-fired generators; and
- abolishing the New South Wales government's ETEF will result in increased demand for financial hedging products in the New South Wales market.

The proposed increase in the MRET is also expected to lead to further significant electricity transmission investments as new renewable generation capacity is installed. This is because most renewable generation is likely to be located away from existing generation and at some distance from large load centres.

All of these observations will be relevant to the Commission's consideration of the effectiveness of retail electricity competition in each NEM region.

Appendix A: Analysis of regional NEM prices: 2005 – February 2008

Figure A.9.1 - Avg New South Wales Electricity Price

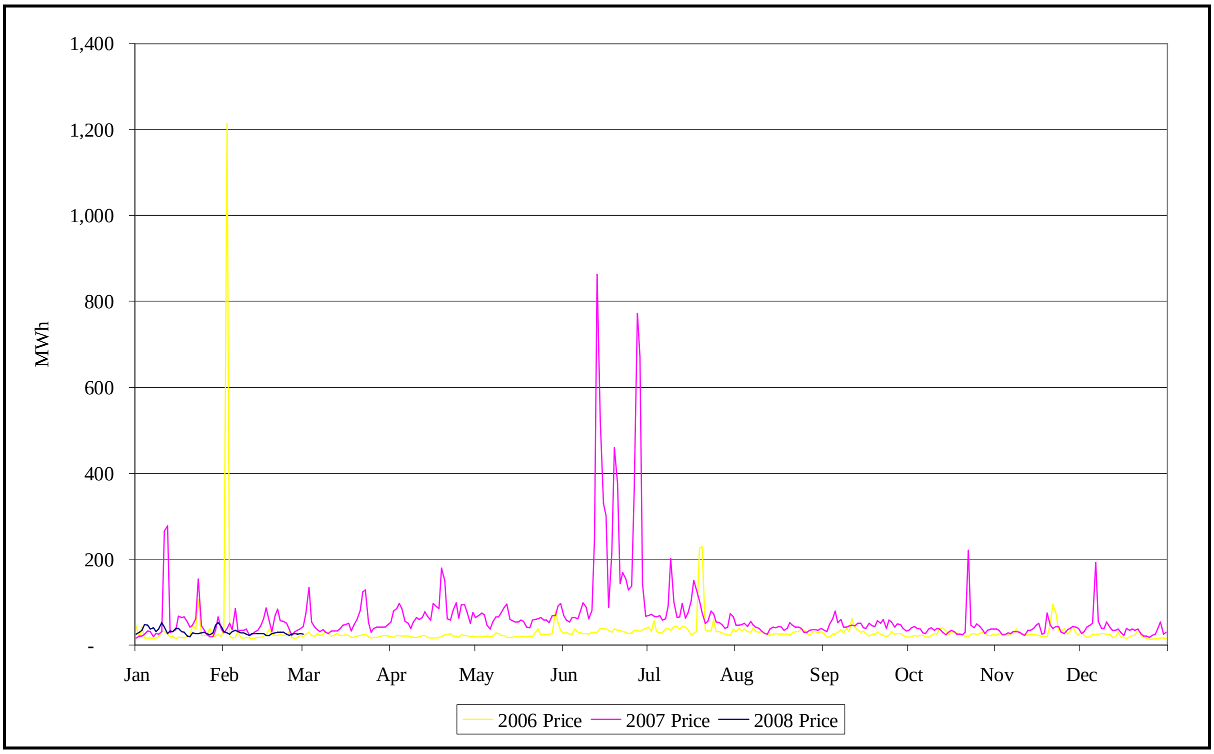


Figure A.9.2 - Avg Vic Electricity Price

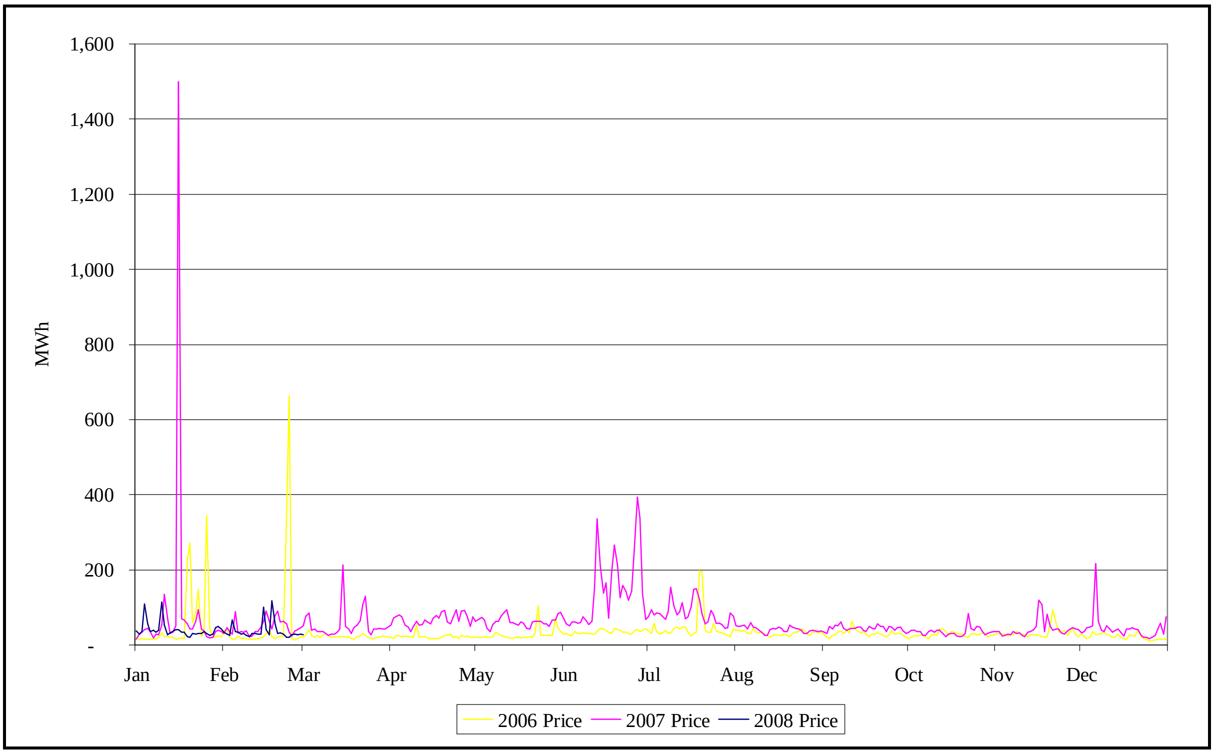


Figure A.9.3 - Avg SA Electricity Price

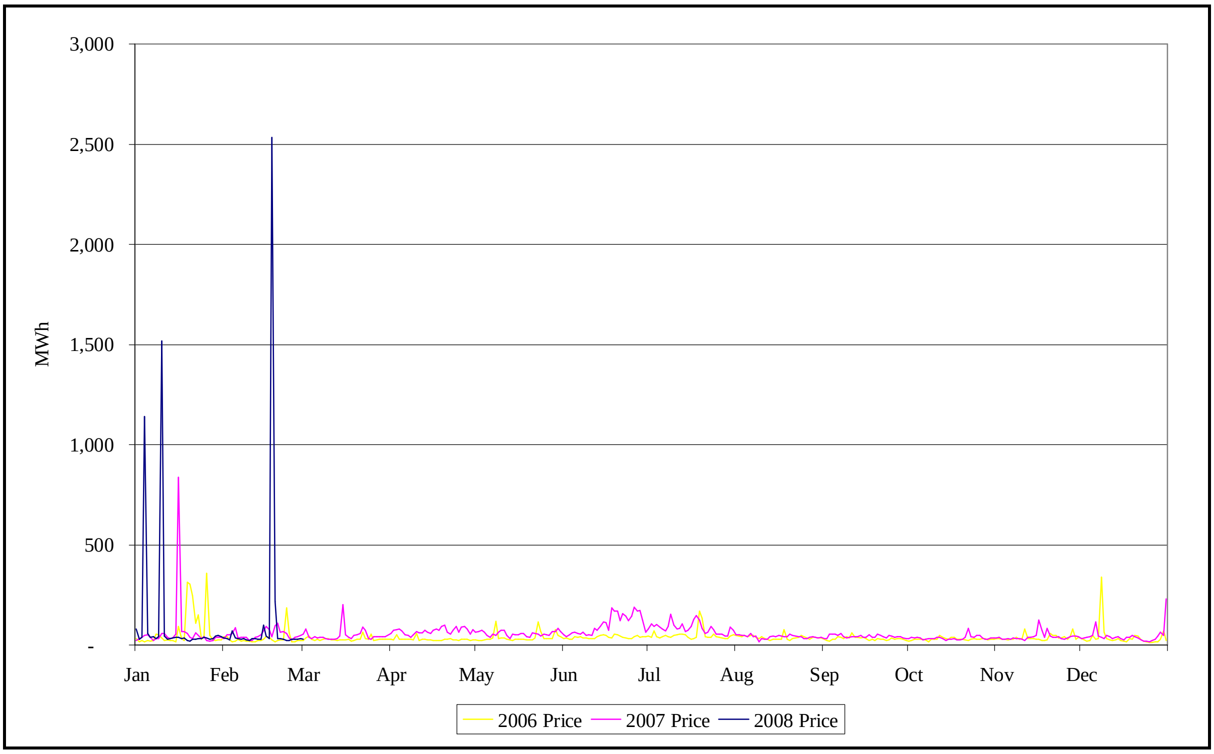


Figure A.9.4 - Avg Snowy Electricity Price

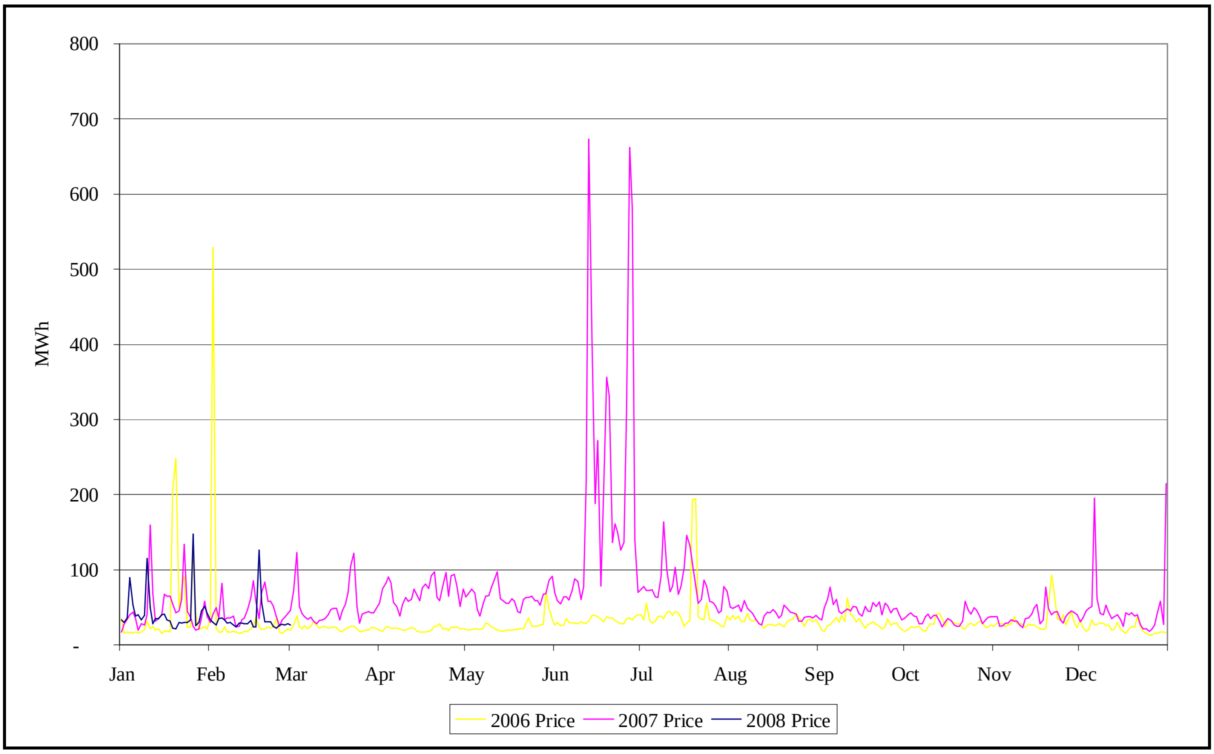


Figure A.9.5 - Avg Tas Electricity Price

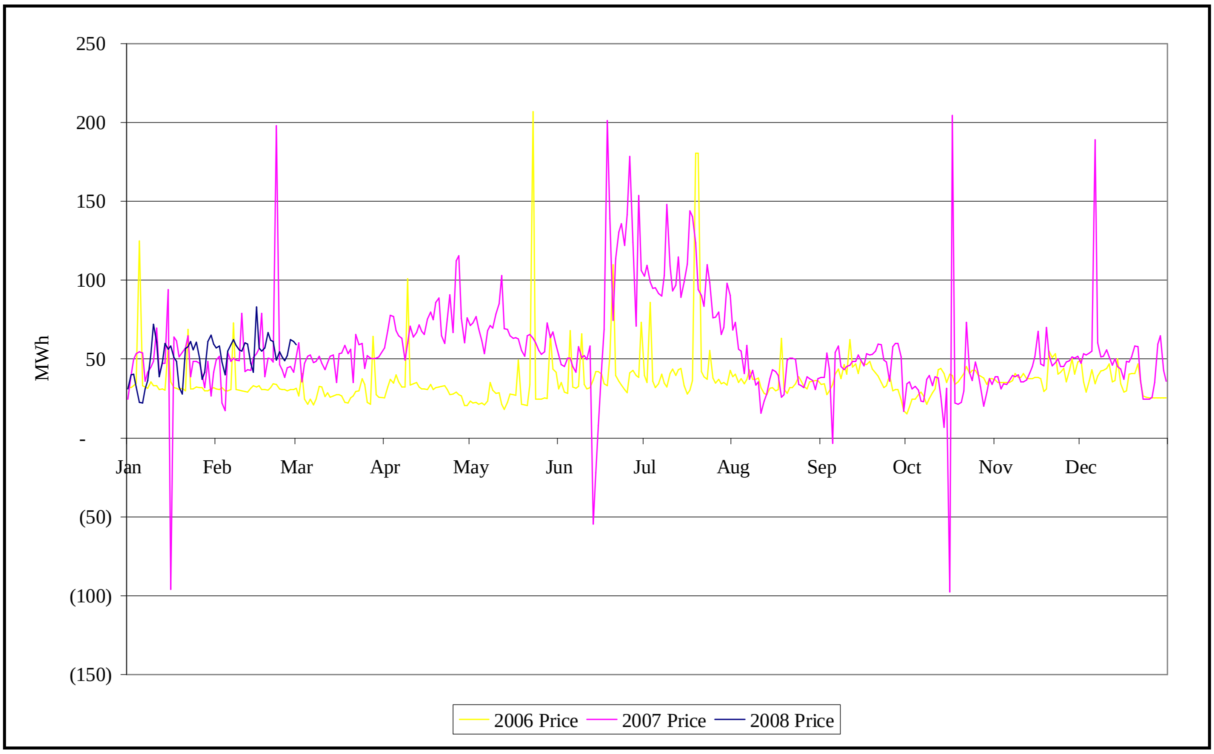
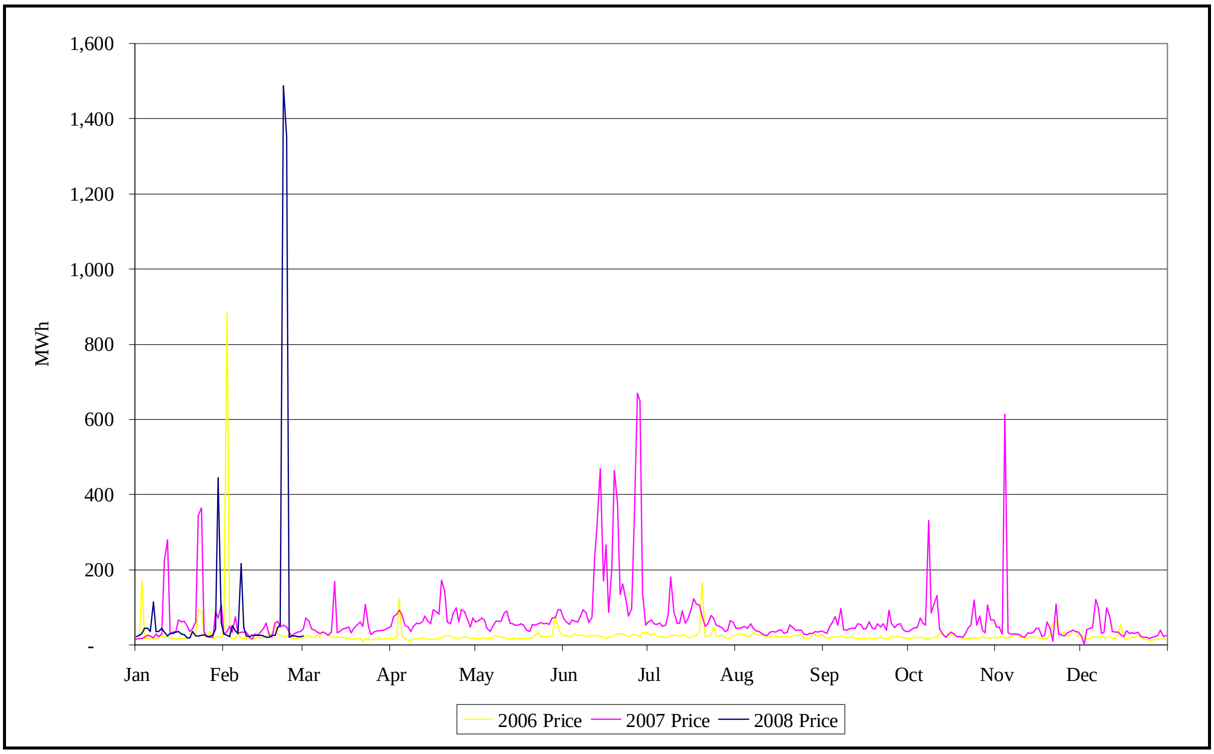


Figure A.9.6 - Avg Qld Electricity Price



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