2 NATIONAL ELECTRICITY MARKET

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Generators in the National Electricity Market sell electricity to retailers through wholesale market arrangements in which the dynamics of supply and demand determine prices and investment. The Australian Energy Regulator monitors the market to ensure that participants comply with the National Electricity Law and National Electricity Rules.

2 NATIONAL ELECTRICITY MARKET

This chapter considers:

- features of the National Electricity Market
- how the wholesale market operates
- the demand for electricity by region, and electricity trade between regions
- spot prices for electricity, including international comparisons.

2.1 Features of the National Electricity Market

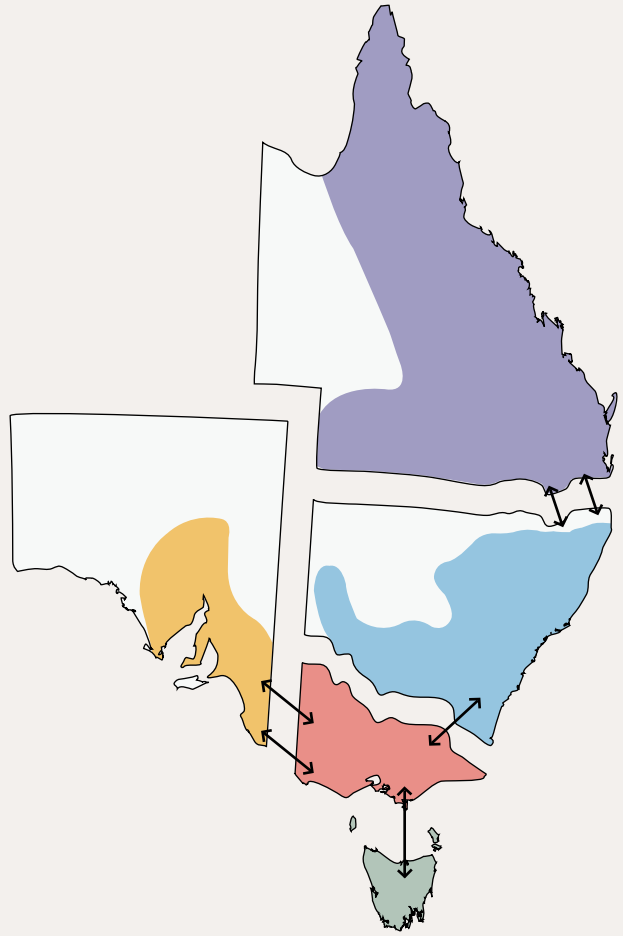
The National Electricity Market (NEM) is a wholesale market through which generators and retailers trade electricity in eastern and southern Australia. There are six participating jurisdictions—Queensland, New South Wales, the Australian Capital Territory (ACT), Victoria, South Australia and Tasmania—that are physically linked by an interconnected transmission network.

The NEM has around 275 registered generators, six state-based transmission networks[1] (linked by cross-border interconnectors) and 13 major distribution networks that collectively supply electricity to end-use customers. In geographical span, the NEM is the largest interconnected power system in the world. It covers a distance of 4500 kilometres, from Cairns in northern Queensland to Port Lincoln in South Australia and Hobart in Tasmania. The market has five regions: New South Wales, Queensland, Victoria, South Australia and Tasmania (see figure 2.1).[2]

1 In New South Wales there are two transmission networks: TransGrid and EnergyAustralia. EnergyAustralia's transmission network assets support the TransGrid network.

2 The former Snowy region was abolished on 1 July 2008. The area formerly covered by the Snowy region is now split between the Victoria and New South Wales regions of the NEM.

Figure 2.1
Regions of the National Electricity Market



The shaded area represents the approximate geological range of the interconnected network in each National Electricity Market region

Source: AER.

The NEM supplies electricity to approximately 8.7 million residential and business customers. In 2007–08, the market generated around 208 terawatt hours (TWh)[3] of electricity with a turnover of almost $11.1 billion (see table 2.1).

Table 2.1 **National Electricity Market at a glance**

Participating jurisdictions	Qld, NSW, Vic, SA, ACT, Tas
NEM regions	Qld, NSW, Vic, SA, Tas
Registered capacity	44 390 MW
Number of registered generators	275
Number of customers	8.7 million
NEM turnover 2007–08	$11.1 billion
Total energy generated 2007–08	208 000 GWh
National maximum winter demand 2007–08 (18 July 2007)	34 422 MWh
National maximum summer demand 2007–08 (14 January 2008)	31 990 MWh

NEM, National Electricity Market; MW, megawatt; GWh, gigawatt hour; MWh, megawatt hour.

Sources: NEMMCO; ESAA, *Electricity Gas Australia*, 2008, p. 26.

2.2 How the National Electricity Market works

The NEM is a wholesale pool into which generators sell their electricity. The main customers are retailers, which buy electricity for resale to business and household customers. While it is also possible for an end-use customer to buy directly from the pool, few choose this option.

The market has no physical location, but is a virtual pool in which a central operator aggregates and dispatches supply bids to meet demand. The National Electricity Market Management Company (NEMMCO) has managed the operation of the NEM since 1998, but this role is scheduled to transfer to a new body, the Australian Energy Market Operator (AEMO), on 1 July 2009. The Australian Energy Regulator (AER) monitors the market to ensure that participants comply with the National Electricity Law and Rules.

3 One TWh is equivalent to 1000 gigawatt hours (GWh), 1 000 000 megawatt hours (MWh) and 1 000 000 000 kilowatt hours (KWh). One TWh is enough energy to light 10 billion light bulbs with a rating of 100 watts for one hour.

Box 2.1 Development of the National Electricity Market

Historically, governments owned and operated the electricity supply chain from generation through to retailing. There was no wholesale market because generation and retail were operated by vertically integrated state-based utilities. Typically, each jurisdiction generated its own electricity needs, with limited interstate trade.

Australian governments began to reform the electricity industry in the 1990s. The vertically integrated utilities were separated into generation, transmission, distribution and retail businesses. For the first time, generation and retail activities were exposed to competition. This created an opportunity to develop a wholesale market that extended beyond jurisdictional borders.

The Special Premiers' Conference in 1991 agreed to establish the National Grid Management Council to coordinate the development of the electricity industry in eastern and southern Australia. In early 1994, the Council of Australian Governments developed a code of conduct for the operation of a national grid, consisting of the transmission and distribution systems in Queensland, New South Wales, the ACT, Victoria and South Australia. In 1996, these jurisdictions agreed to pass the National Electricity Law, which provided the legal basis to create the NEM.

During the transition to a national market, Victoria and New South Wales trialled wholesale electricity markets that used supply and demand principles to set prices. The NEM commenced operation in December 1998, with Queensland, New South Wales, Victoria, South Australia and the ACT as participating jurisdictions.

While Queensland was part of the NEM from inception, it was not physically interconnected with the market until 2000–01 when two transmission lines (Directlink and the Queensland to New South Wales interconnector) linked the Queensland and New South Wales networks. Tasmania joined the NEM in 2005 and was physically interconnected with the market in April 2006 with the opening of Basslink, a submarine transmission cable from Tasmania to Victoria.

The NEM experienced a regional boundary change on 1 July 2008 when the Snowy region was abolished. The area formerly covered by the region is now split between the Victoria and New South Wales regions of the NEM. The other regions—Queensland, South Australia and Tasmania—follow jurisdictional boundaries.

The design of the NEM reflects the physical characteristics of electricity. This means:

- Supply must meet demand at all times because electricity cannot be economically stored. This requires coordination to avoid imbalances that could seriously damage the power system.
- One unit of electricity cannot be distinguished from another, making it impossible to determine which generator produced which unit of electricity and which market customer consumed that unit. The use of a common trading pool addresses this issue by removing any need to trace particular generation to particular customers.

The NEM is a gross pool, meaning that all sales of electricity must occur through a central trading platform. In contrast, a net pool or voluntary pool would allow generators to contract with market customers directly for the delivery of some electricity. Western Australia's electricity market uses a net pool arrangement (see chapter 7). Both market designs require the market operator to be informed of all sales so that the physical delivery of electricity can be centrally managed.

Unlike some overseas markets, the NEM does not provide additional payments to generators for capacity or availability. This characterises the NEM as an 'energy-only' market and explains the high price cap of $10 000 per megawatt hour (MWh).[4] Generators earn their income in the NEM from market transactions,

4 The Australian Energy Market Commission's (AEMC) Reliability Panel stated in its 2007 reliability review that it intends to put forward a Rule change proposal to the AEMC to raise the market price cap to $12 500 effective 1 July 2010. See AEMC, *Comprehensive reliability review*, Final report, December 2007, p. 51.

either in the spot or ancillary services[5] markets or by trading hedge instruments in financial markets[6] outside NEM arrangements.

2.2.1 Market operation

NEMMCO coordinates a central dispatch to manage the wholesale spot market. The process matches generator supply offers to demand in real time. NEMMCO issues instructions to each generator to produce the required quantity of electricity that will meet demand at all times at the lowest available cost, while maintaining the technical security of the power system. NEMMCO does not own any physical network or generation assets.

Some generators bypass the central dispatch process: they might only generate intermittently (such as wind generators)[7], may not be connected to a transmission network, and/or might produce exclusively for their own use (such as in remote mining operations).

2.2.2 Demand and supply forecasting

NEMMCO continuously monitors demand and capacity across the NEM and issues demand and supply forecasts to help participants respond to the market's requirements. While demand varies, industrial, commercial and household users each have relatively predictable patterns, including seasonal demand peaks related to extreme temperatures. NEMMCO uses data such as historical load (demand) patterns and weather forecasts to develop demand projections. Similarly, it estimates the adequacy of supply in its projected assessment of system adequacy (PASA) reports. It publishes a seven-day PASA report that is updated every two hours, and a two-year PASA report that is updated weekly.

2.2.3 Central dispatch and spot prices

Market supply is based on the offers of generators to produce particular quantities of electricity at various prices for each of the five-minute dispatch periods in a day. Generators must lodge offer bids ahead of each trading day.

Generator offers are affected by a range of factors, including plant technology. For example, coal-fired generators need to ensure their plants run constantly to cover their high start-up costs and may offer to generate some electricity at low or negative prices to guarantee dispatch.[8] Peaking generators face high operating costs and normally offer to supply electricity only when prices are high.

NEMMCO determines which generators are dispatched by stacking the offer bids of all generators in ascending price order for each five-minute dispatch period. NEMMCO dispatches the cheapest generator bids first, then progressively more expensive offers until enough electricity is dispatched to satisfy demand. This results in demand being met at the lowest possible cost. In practice, the dispatch order may be modified by a number of factors, including generator ramp rates—that is, how quickly generators can adjust their level of output—and congestion in transmission networks.

The dispatch price for a five-minute interval is the offer price of the highest (marginal) priced megawatt (MW) of generation that must be dispatched to meet demand. For example, in figure 2.2, the demand for electricity at 4.15 is about 350 MW. To meet this level of demand, the four generators offering to supply at prices up to $37 must be dispatched. The dispatch price is therefore $37. By 4.20, demand has risen to the point where a fifth generator needs to be dispatched. This higher cost generator has an offer price of $38, which drives the price up to that level.

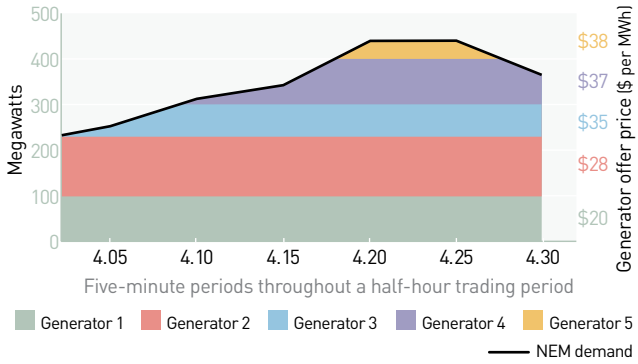
5 NEMMCO operates a market for a number of ancillary services. These include frequency control services that relate to electricity supply adjustments to maintain the power system frequency within the standard. Generators can bid offers to supply these services into spot markets that operate in a similar way to the wholesale energy market.

6 See chapter 3.

7 The AEMC published a final Rule determination on 1 May 2008 that requires new intermittent generators to register under the new classification of 'semi-scheduled generator'. These generators will be required to participate in the central dispatch process, including by submitting offers and by limiting their output whenever requested by NEMMCO.

8 The minimum allowed bid price is -$1000 per MWh.

Figure 2.2
Illustrative generator offers (megawatts) at various prices



Source: NEMMCO.

A wholesale spot price is determined for each half-hour period (trading interval) and is the average of the five-minute dispatch prices during that interval. In figure 2.2, the spot price in the 4.00–4.30 interval is about $37 per MWh. This is the price all generators receive for their supply during this 30 minute period and the price market customers pay for the electricity they use in that period. A separate spot price is determined for each region, taking into account the physical losses in the transport of electricity over distances and transmission congestion that can sometimes isolate particular regions from the national market (see section 2.4).

The price mechanism in the NEM allows spot prices to respond to a tightening in the supply–demand balance. This creates signals for demand-side responses. For example, if suitable metering arrangements are available, some customers may be able to reduce their consumption during peak demand periods when prices are high (see section 2.6). In the longer term, price movements also create signals for new investment (see sections 1.3 and 2.6).

2.3 Demand and capacity

Annual electricity consumption in the NEM rose from under 170 000 gigawatt hours (GWh) in 1999–2000 to about 208 000 GWh in 2007–08 (see figure 2.3(a)). The entry of Tasmania in 2005 accounted for around 10 000 GWh. Demand levels fluctuate throughout the year, with peaks occurring in summer (for air conditioning) and winter (for heating). The peaks are closely related to temperature. Figure 2.3(b) shows that seasonal peaks have risen nationally from around 26 000 MW in 1999–2000 to over 33 000 MW in 2007–08. The volatility in the summer peaks reflects variations in weather conditions from year to year.

Table 2.2 sets out the demand for electricity across the NEM since 1999–2000. Reflecting its population base, New South Wales has the highest demand for electricity, followed by Victoria and Queensland. Demand is considerably lower in the less populated regions of South Australia and Tasmania.

Figure 2.4 compares seasonal demand across the regions. Victoria, South Australia and Queensland experience high demand in summer due to air conditioning loads. Tasmania tends to experience its maximum demand in winter due to heating loads. New South Wales has alternated between summer and winter peaking for several years.

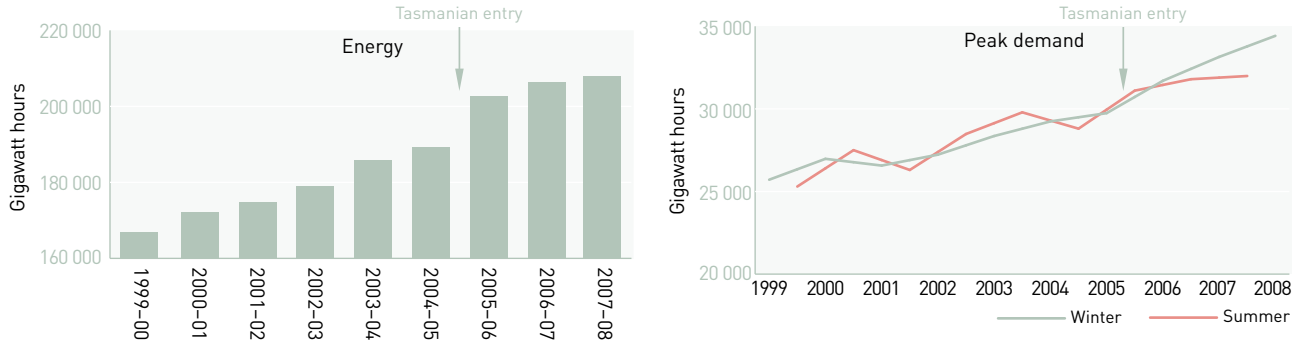
2.4 Trade between the regions

The NEM promotes efficient generator use by allowing trade in electricity between the five regions, which are linked by transmission interconnectors. Trade enhances the reliability of the power system by allowing the regions to draw on a wider pool of reserves to manage system constraints and outages.

Trade also provides economic benefits by allowing high-cost generating regions to import electricity from lower cost regions. For example, on a day of peak electricity demand in South Australia, low-cost baseload power from Victoria may provide a competitive alternative to South Australia's high-cost peaking generators. NEMMCO can dispatch electricity from lower cost regions and export it to South Australia until the technical capacity of the interconnectors is reached.

Figures 2.3a and 2.3b

National Electricity Market energy consumption and peak demand since 1999



Sources: NEMMCO; AER.

Table 2.2 **Annual energy demand (terawatt hours)**

	Qld	NSW	Snowy[2]	Vic	SA	Tas[1]	National
2007–08	51.5	78.8	1.6	52.3	13.3	10.3	208.0
2006–07	51.4	78.6	1.3	51.5	13.4	10.2	206.4
2005–06	51.3	77.3	0.5	50.8	12.9	10.0	202.8
2004–05	50.3	74.8	0.6	49.8	12.9		189.7
2003–04	48.9	74.0	0.7	49.4	13.0		185.3
2002–03	46.3	71.6	0.2	48.2	13.0		179.3
2001–02	45.2	70.2	0.3	46.8	12.5		175.0
2000–01	43.0	69.4	0.3	46.9	13.0		172.5
1999–00	41.0	67.6	0.2	45.8	12.4		167.1

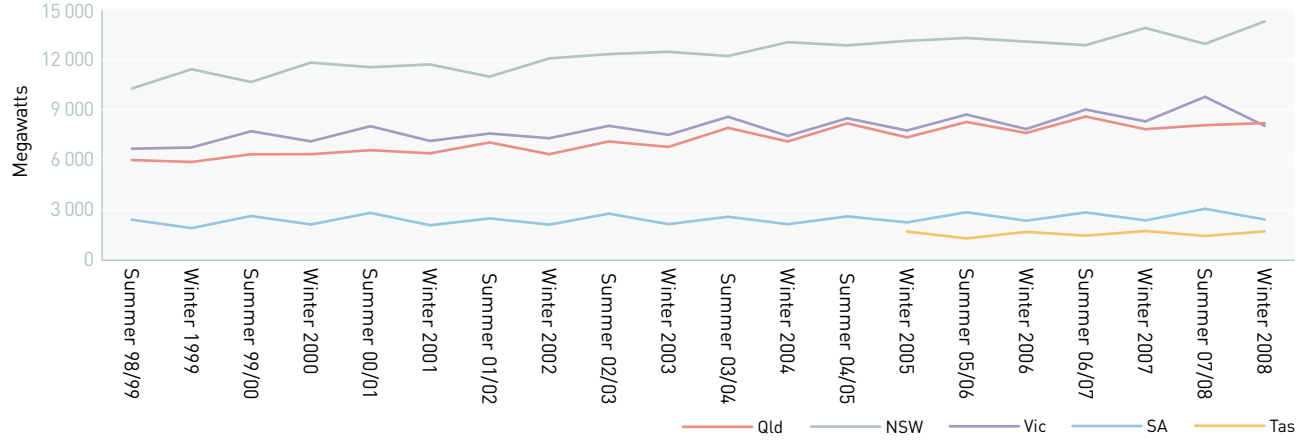
Notes:

1. Tasmania entered the market on 29 May 2005.
2. The Snowy region was abolished on 1 July 2008.

Source: NEMMCO.

Figure 2.4

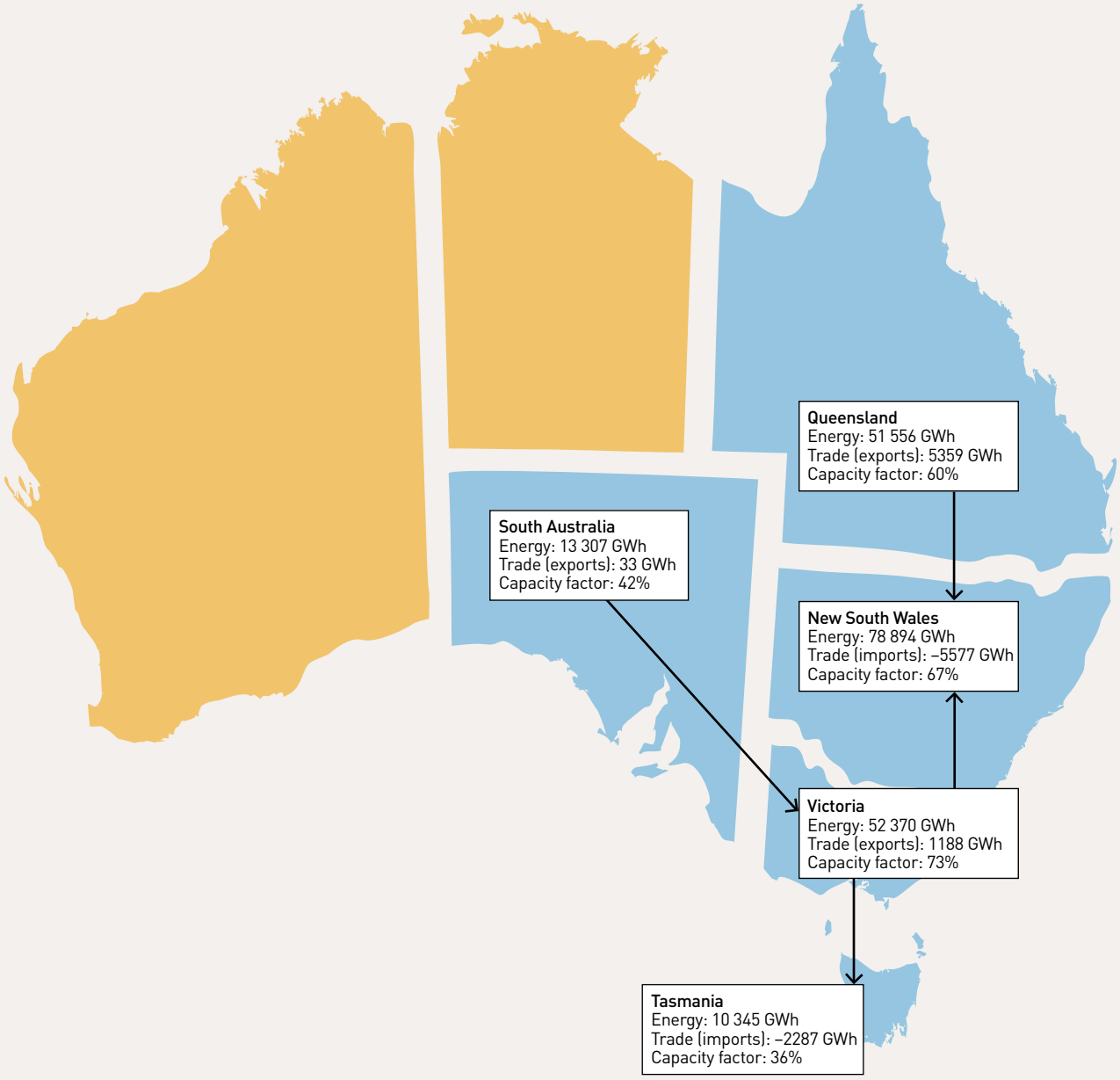
Seasonal peak demand in the National Electricity Market



Sources: NEMMCO; AER.

Figure 2.5

Trade flows across National Electricity Market regions in 2007–08



GWh, gigawatt hour.

Notes:

1. Energy refers to electricity consumption.
2. Capacity factor refers to the proportion of local generation capacity in use.
3. The Snowy region (not shown) was a net exporter of 1809 GWh in 2007–08. The region was abolished on 1 July 2008. The area formerly covered by the Snowy region is now split between the Victoria and New South Wales regions of the National Electricity Market.

Sources: NEMMCO; AER.

Figure 2.6
Inter-regional trade as percentage of regional energy consumption

Sources: NEMMCO; AER.

Figure 2.5 shows annual electricity consumption and trade between the regions in 2007–08. The figure also shows each region's generation capacity factor (the utilisation of local generation capacity). The NEM's inter-regional trade relationships are also reflected in figure 2.6, which shows the net trading position of the regions since the NEM commenced.

Figures 2.5 and 2.6 show that:

- New South Wales is a net importer of electricity. It relies on local baseload generation, but has limited peaking capacity at times of high demand.[9] This puts upward pressure on prices in peak periods, making imports a competitive alternative. New South Wales continued to be a net importer in 2007–08, although at a lesser rate than in 2006–07. Imports have accounted for between 5 and 13 per cent of the state's energy consumption since the NEM commenced.
- Victoria is a net exporter because it has substantial low-cost baseload capacity. This is reflected in the region's 73 per cent capacity factor, the highest for any region. Victoria tends to import mainly at times of peak demand when its regional capacity is stretched. While Victoria has consistently been a net exporter, its exports as a share of consumption have fallen from around 10 per cent in the early years of the NEM to about 2 per cent in 2007–08.
- Queensland's installed capacity exceeds its demand for electricity, making it a significant net exporter. Queensland exports have steadily risen since 2001–02 and have exceeded 10 per cent of the state's annual energy consumption since 2005–06.
- South Australia, historically the most trade-dependent region, imported over 25 per cent of its energy requirements in the early years of the NEM. This reflected the region's relatively higher fuel costs, resulting in high-cost generation. South Australia has significantly reduced its reliance on imports since 2005–06, and in 2007–08 it became a net exporter for the first time. The shift reflects new investment in generation since 1999, including substantial recent investment in wind capacity. South Australia was less affected by the drought than other regions as it has no hydroelectric generation and its baseload generators use cooling technologies that do not rely on fresh water.

9 The New South Wales region gained additional hydroelectric peaking capacity following the abolition of the Snowy region on 1 July 2008.

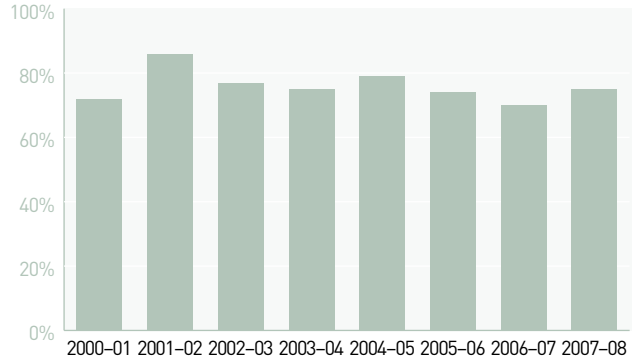
> Tasmania has been a net importer since its interconnection with the NEM in 2006. Tasmanian imports rose to over 20 per cent of its electricity requirements in 2007–08, mainly because drought has constrained its ability to generate hydroelectricity. This also contributed to Tasmania's extremely low capacity factor.

2.4.1 Market separation

The NEM central dispatch determines a separate spot price for each region of the NEM. In the absence of network constraints, interstate trade brings prices across the regions towards alignment. Due to transmission losses that occur when transporting electricity over distances, it is normal to have some disparities between regional prices. More significant price separation may occur if an interconnector is congested. For example, imports may be restricted when import requirements exceed an interconnector's design limits. Import capability may also be reduced when an interconnector is undergoing maintenance or due to an unplanned outage. The availability of generation plant and the bidding behaviour of generators can also contribute to transmission congestion.

When congestion restricts a high-demand region's ability to import electricity, prices in that region may spike. For example, if low-cost Victorian electricity is constrained from flowing into South Australia on a day of high demand, more expensive South Australian generation—for example, local peaking plant—would need to be dispatched in place of imports. This would drive South Australian prices above those in Victoria.

Figure 2.7
Regional price alignment as a percentage of trading hours

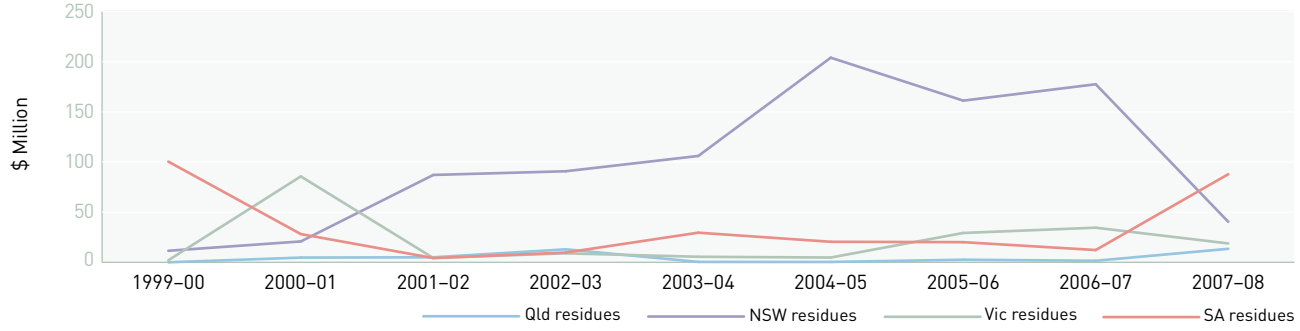


Sources: NEMMCO; AER.

Figure 2.7 indicates that the NEM operates as an 'integrated' market with price alignment across all regions for around 75 per cent of the time. The market is considered aligned when every interconnector in the NEM is unconstrained and electricity can flow freely between all regions. There may still be price differences between regions due to loss factors that occur in the transport of electricity.

While the extent of alignment is an indicator of how effectively the market is working, it should be noted that full alignment would require significant investment to remove all possible causes of congestion. AER research indicates that the economic costs of transmission congestion are relatively modest given the scale of the market, although these costs have risen since 2003–04 (see section 4.7).

Figure 2.8
Settlement residues



Sources: NEMMCO; AER.

2.4.2 Settlement residues

When there is price separation between regions, electricity tends to flow from lower priced regions to higher priced regions. The exporting generators are paid at their local regional spot price, while importing customers (usually energy retailers) must pay the higher spot price in the importing region. The difference between the price paid and the price received multiplied by the amount of electricity exported is called a settlement residue. Over time, these residues accrue to the market operator.

Figure 2.8 charts the annual accumulation of inter-regional settlement residues in each region. There is some volatility in the data, reflecting that a complex range of factors can contribute to price separation: for example, the availability of transmission interconnectors and generation plant; weather conditions; and the bidding behaviour of generators.

New South Wales recorded settlement residues ranging from around $90 million to $200 million each year from 2001–02 to 2006–07. This reflects the region's status as the largest importer of electricity (in dollar and volume terms) in the NEM, which can make it vulnerable to price separation events. In 2007–08, New South Wales settlement residues fell by around 75 per cent due to more benign market conditions. Conversely, South Australian residues increased from a low base to almost $88 million in 2007–08 due to record summer and autumn prices in the region.

As net exporters, Queensland and Victoria tend not to accumulate large settlement residue balances.

Price separation creates risks for parties that contract across regions. NEMMCO offers a risk management instrument by holding quarterly auctions to sell the rights to future residues. An explanation of the auction process is provided in section 4.7.

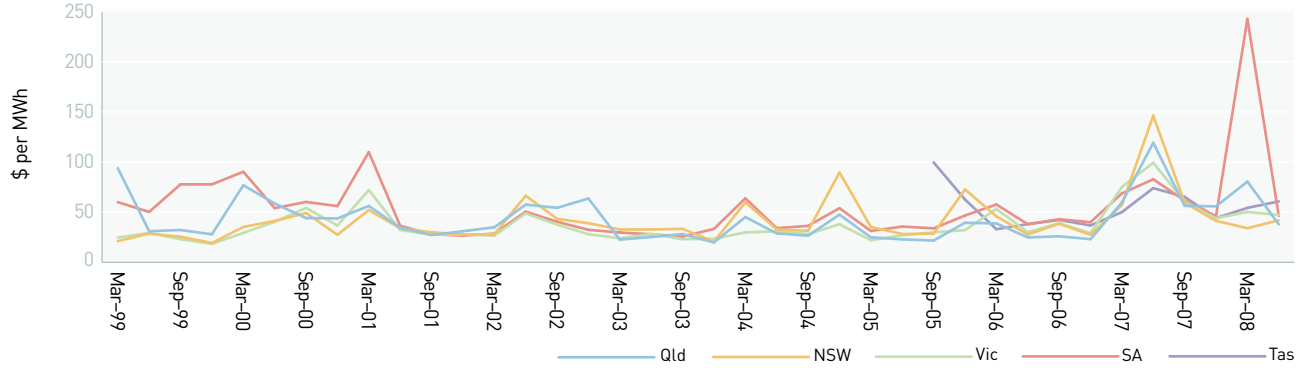
2.5 National Electricity Market prices

The central dispatch process determines a spot price for each NEM region every 30 minutes. As noted, prices can vary between regions because of losses in transportation and transmission congestion, which sometimes restricts inter-regional trade.

The AER closely monitors the market and reports weekly on wholesale and forward market activity. It also publishes more detailed analyses of extreme price events. Figure 2.9 charts quarterly volume-weighted average prices since the NEM commenced, while table 2.3 sets out annual volume-weighted prices. Figure 2.10 provides a more detailed snapshot of weekly prices since November 2006. Overall, prices tended to fall in the early years of the NEM—especially in Queensland and South Australia—following investment in new transmission and generation capacity. In the past two years, drought, record peak demands and other factors have seen prices rise to record levels.

Figure 2.9

Quarterly volume-weighted average prices—National Electricity Market



MWh, megawatt hour.

Sources: NEMMCO; AER.

Table 2.3 **Annual average National Electricity Market prices by region (dollars per megawatt hour)**

	Qld	NSW	Snowy[2]	Vic	SA	Tas[3]
2007–08	58	44	31	51	101	57
2006–07	57	67	38	61	59	51
2005–06	31	43	29	36	44	59
2004–05	31	46	26	29	39	
2003–04	31	37	22	27	39	
2002–03	41	37	27	30	33	
2001–02	38	38	27	33	34	
2000–01	45	41	35	49	67	
1999–2000	49	30	24	28	69	
1998–1999[1]	60	25	19	27	54	

Notes:

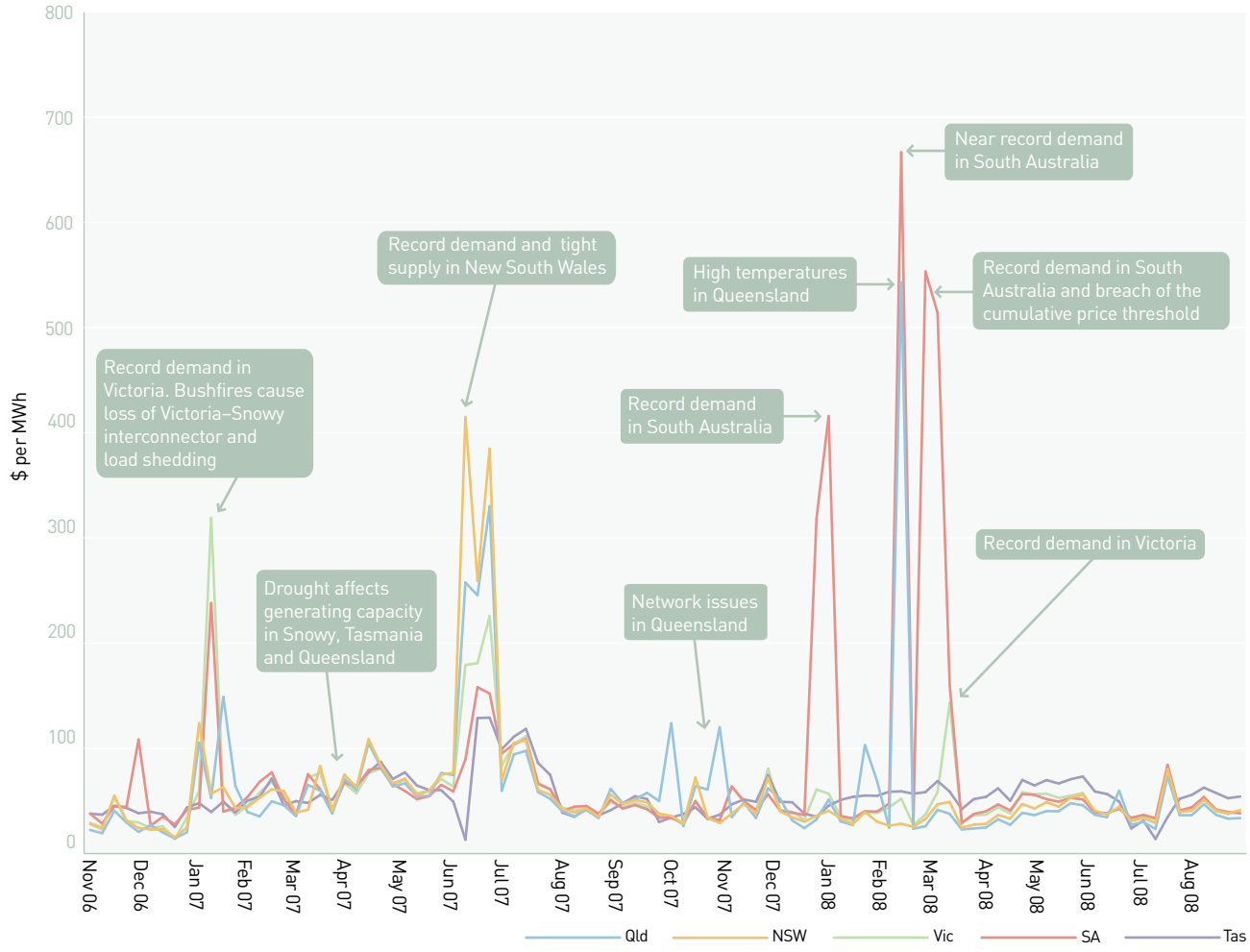
1. Six months to 30 June 1999.
2. The Snowy region was abolished on 1 July 2008.
3. Tasmania entered the market on 29 May 2005.

Source: NEMMCO.

A variety of factors led to significantly higher prices in 2006–07. In January 2007, bushfires caused an outage of the Victoria–Snowy interconnector, causing price spikes in Victoria and South Australia. Network issues in Queensland in late January also affected prices. From around March 2007, drought began to impact on prices. The drought constrained hydroelectric generating capacity in New South Wales, Tasmania and Victoria and also limited the availability of water for cooling in some coal-fired generators.

These conditions were exacerbated in winter 2007 by a number of generator outages, network outages and generator limitations. Tight supply was accompanied by record electricity demand as cold winter days increased heating requirements.

Figure 2.10
National Electricity Market prices, November 2006–September 2008



Note: Weekly volume-weighted average prices.

Sources: NEMMCO; AER.

2.5.1 Wholesale market update: 2007–2008

The drought continued to affect wholesale electricity prices in New South Wales, Victoria, Queensland and Tasmania during the September quarter of 2007. South Australia was less affected as its generators do not depend on fresh water for cooling. By the end of the quarter, drought conditions in New South Wales and Queensland had eased and prices across the NEM had fallen back towards pre-drought levels.

Wholesale prices in the December quarter were relatively subdued across most of the NEM. Queensland experienced some high-price events due to planned and unplanned network outages and aggressive bidding by a number of generators.

The March quarter of 2008 was characterised by high electricity prices in South Australia, Queensland and Victoria. South Australia experienced record high prices, averaging $243 per MWh over the quarter compared to the previous NEM record of $146 per MWh.[10]

10 The previous highest quarterly average was for New South Wales in the June quarter of 2007.

A number of factors contributed to South Australia's record high prices:

- Adelaide experienced high temperatures in January and February and an unprecedented 15-day heat wave in March 2008. The extreme temperatures led to record demand.
- A significant proportion of South Australia's electricity is sourced from Victorian generators via the Heywood and Murraylink interconnectors. In December 2007, the South Australian transmission network owner, ElectraNet, reduced the maximum allowable flows on the Heywood interconnector by about 25 per cent. This constrained the supply of low-cost generation from Victoria.
- AGL Energy, which owns about 39 per cent of South Australia's generation capacity, bid a significant proportion of its capacity at close to the price cap during the periods of high demand.

In combination, these factors led to extreme prices in South Australia in March 2008. The National Electricity Rules provide a mechanism that triggers an administered price cap during times of sustained high prices. When the sum of the prices over the previous week exceeds $150 000 (the cumulative price threshold),[11] administered pricing automatically caps the price at $300 per MWh until the end of that trading day.

On the last day of the South Australian heatwave, prices reached the cumulative price threshold and administered price caps were applied.[12] This was the first time that administered pricing had been triggered since the commencement of the NEM in 1998.

The AER is investigating the high price events in South Australia and, in particular, whether generator bidding behaviour breached the National Electricity Law and Rules.[13] The AER is also investigating the flow limits placed on the Heywood interconnector by ElectraNet.[14]

In the June quarter of 2008, prices across the NEM were relatively subdued, with no extreme price events. This is consistent with the normal historical tendency for peak demand and prices to be relatively stable during autumn. The unusually high prices in autumn 2007 mainly reflected drought conditions. More benign weather conditions in 2008 led to a return to lower prices.

The market in the third quarter of 2008 remained relatively quiet, apart from a price spike across the mainland NEM regions on 23 July due to an unplanned outage of two transmission lines in Victoria. The AER is investigating this incident.

2.6 Price volatility

Spot price volatility in the NEM reflects fluctuating supply and demand conditions. The market is sensitive to changes in these conditions, which can occur at short notice. For example, electricity demand can rise swiftly on a hot day. Similarly, a generator or network outage can quickly increase regional spot prices. The sensitivity of the market to changing supply and demand conditions can result in considerable price volatility.

While figure 2.10 provides an indicator of volatility in weekly prices, it masks more extreme spikes that can occur during half-hour trading intervals. On occasion, half-hour spot prices approach the market cap of $10 000 per MWh. Two indicators of the incidence of extreme price events are:

- the number of trading intervals where the price is above $5000 per MWh (see figures 2.11 and 2.12)
- the number of trading intervals per week where the price is more than three times the volume-weighted average price (see figure 2.13).

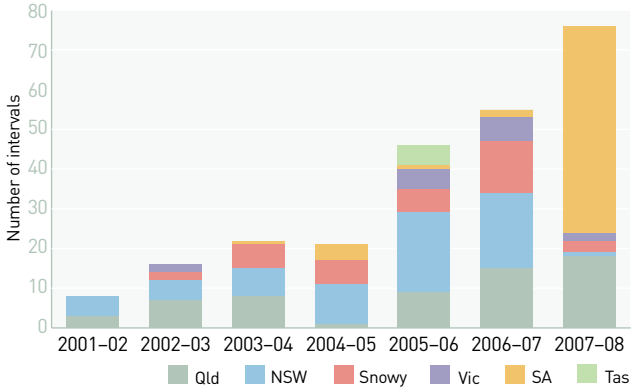
11 The AEMC Reliability Panel stated in its 2007 reliability review that it intends to put forward a Rule change proposal to the AEMC to raise the cumulative price threshold to $187 500 (being 15 times the level of the recommended market price cap) effective 1 July 2010 (See AEMC, *Comprehensive reliability review*, Final report, December 2007, p. 85).

12 In March 2008, the administered price cap was $100 per MWh during peak periods and $50 per MWh at other times. The AEMC completed a review of the administered price cap on 21 May 2008 and determined that from 25 May 2008, the administered price cap would be $300 per MWh for all regions at all times.

13 AER, *Quarterly compliance report January–March 2008*, June 2008, p. 3.

14 AER, *Quarterly compliance report April–June 2008*, August 2008, pp. 3–4.

Figure 2.11
Number of trading intervals above $5000 per megawatt hour (annual)



Note: Trading intervals are of 30 minutes duration

Sources: NEMMCO; AER.

The AER's weekly reports on wholesale market activity highlight factors contributing to spot prices that are more than three times the volume-weighted average price for the week. The AER also publishes a report on every price event above $5000 per MWh.

The incidence of trading intervals with prices above $5000 per MWh has increased since the NEM commenced (see figure 2.11). The number of events more than doubled from 2004–05 to 2005–06 and continued to rise to 76 events in 2007–08. Figure 2.12 sets out the data on a quarterly basis since January 2005 and highlights some of the factors responsible for the price spikes. Figure 2.13 indicates that trading intervals with prices three times above the volume-weighted average for the week occur most frequently in summer and winter, when peak demand is highest.

Many factors can cause price spikes. While the cause of a high-price event is not always clear, underlying causes might include:

- high demand that requires the dispatch of high-cost peaking generators
- a generator outage that affects regional supply
- transmission network outages or congestion that restricts the flow of cheaper imports into a region
- a lack of effective competition in certain market conditions
- a combination of factors.

Table 2.4 summarises key features of extreme price events in 2007–08, noting the regions in which they occurred and indicating identified causes. In many instances, the table groups multiple events based on the AER's public reporting of these events in 2007–08.

The most common causes of high-price events identified by the AER in 2007–08 were:

- extreme weather
- network availability flow limits placed on particular transmission lines and interconnectors
- generator bidding behaviour.

On two occasions, errors by NEMMCO also contributed to high spot prices.

As noted, a combination of several factors contributed to high prices in South Australia during the March quarter of 2008. South Australian spot prices exceeded $5000 per MWh on 51 occasions and, on 17 March 2008, administered pricing was triggered (see section 2.5).

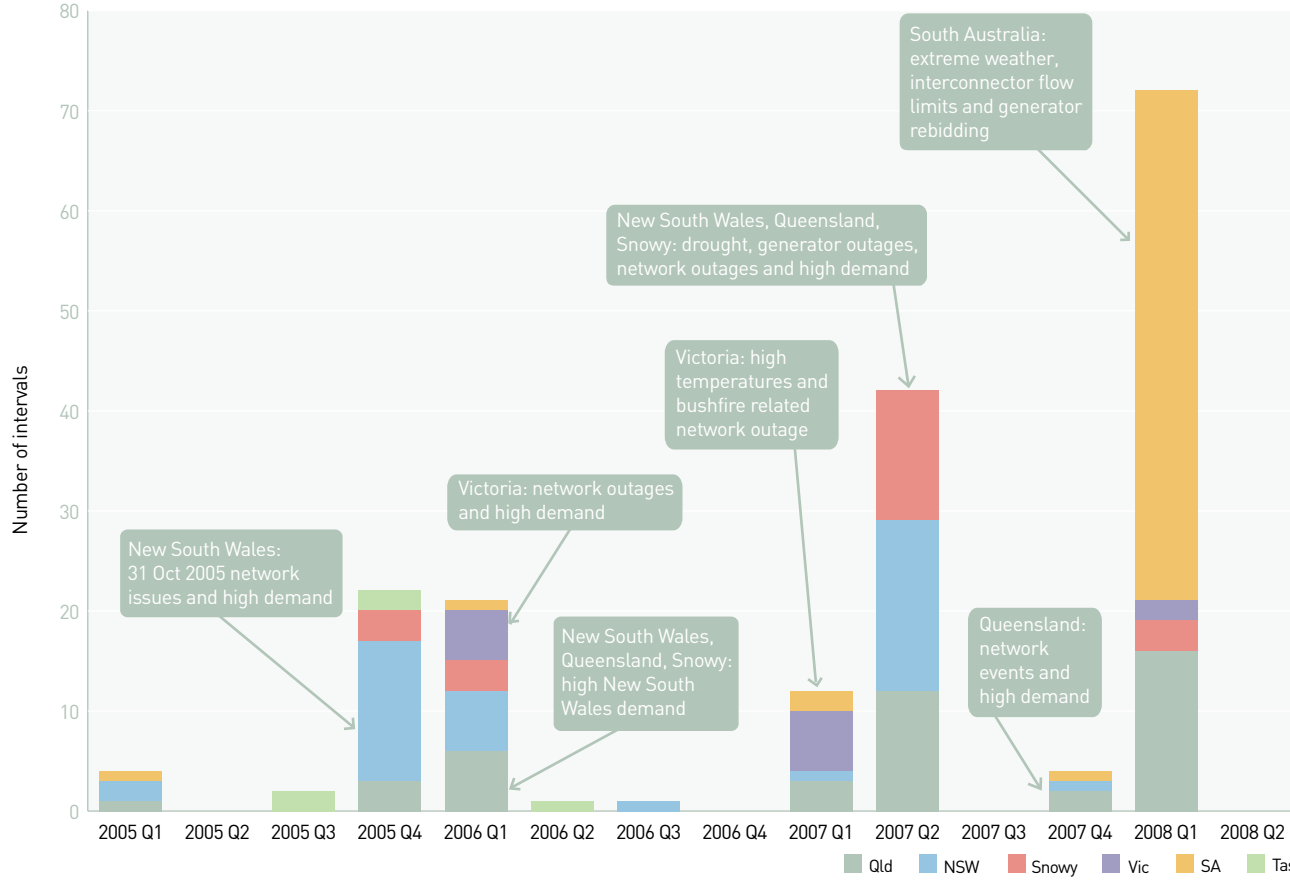
Price spikes can have a material impact on market outcomes. If prices approach $10 000 per MWh for just three hours in a year, the average annual price may rise by almost 10 per cent. Generators and retailers typically hedge against this risk by taking out contractual arrangements in financial markets (see chapter 3).

Extreme price events help to provide solutions to tight supply conditions. In particular, they create incentives to invest in peaking generation plant for operation during periods of peak demand.

Extreme price events may also create incentives for retailers to contract with customers to manage their demand in peak periods. This might involve a retailer

Figure 2.12

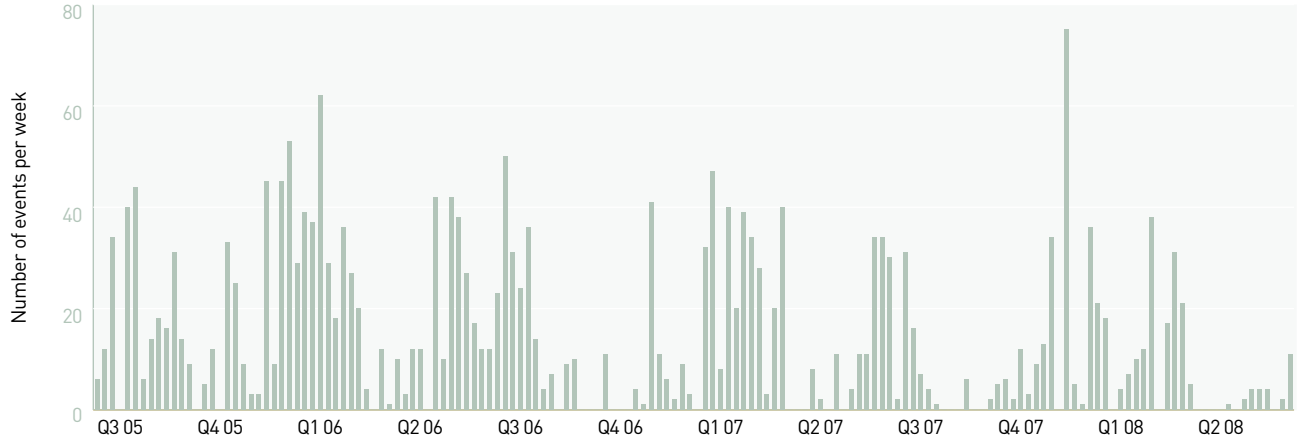
Number of trading intervals above $5000 per megawatt hour (quarterly)



Sources: NEMMCO; AER.

Figure 2.13

Trading intervals with prices above three times the weekly volume-weighted average



Sources: NEMMCO; AER.

offering a customer financial incentives to reduce consumption at times of high system demand to ease price pressures. Effective demand management requires suitable metering arrangements to enable customers to manage their consumption. The Energy Reform Implementation Group noted in 2007 that demand management activity in the NEM was mainly confined to the large customer segment. It estimated that the extent of potential demand-side response in the NEM is around 700 MW across a range of energy-consuming industries.[15] At the small customer level, the Council of Australian Governments agreed in 2007 to a national implementation strategy for the progressive rollout of 'smart' electricity meters to encourage demand-side response (see section 6.6.4 of this report).

Table 2.4 **Price events above $5000 per megawatt hour in 2007–08**

DATE OR PERIOD	REGIONS	NUMBER OF EVENTS	CAUSES IDENTIFIED BY AER
17 March 2008	Victoria and Snowy	2	Extreme temperatures in Victoria and South Australia led to record high demand.
5 to 17 March 2008	South Australia	26	Extreme temperatures in Victoria and South Australia led to record high demand. AGL Energy's strategy of offering a significant proportion of generation capacity at prices above $5000 per MWh, and a limit placed on the flow of electricity on the interconnector between Victoria and South Australia, contributed to the high-price events.
22 to 23 February 2008	Queensland	14	High temperatures in Queensland led to high demand. Generator bidding—including a large proportion of capacity being priced at above $5000 per MWh and rebids by several generators—contributed to the high prices.
30 January 2008 and 7 February 2008	Queensland	2	On 30 January 2008, NEMMCO reclassified as credible the potential loss of two lines in Queensland due to lightning. This reduced the supply of generation from central and north Queensland to Brisbane. A number of generators close to Brisbane offered capacity at prices above $5000 per MWh. On 7 February 2008, lightning again led to the reclassification of the potential loss of a line. To manage the event, NEMMCO constrained off all generation in Queensland and limited flows from New South Wales. The constraints were inappropriate and caused the spot price to exceed $5000 per MWh.
26 January 2008	Snowy	1	A planned network outage in Victoria forced very large flows from Snowy to Victoria. The impact of this outage was not accurately predicted and the direction of flow between these regions was counter to normal spot price signals. Rebidding by Snowy Hydro to reallocate generation between its power stations contributed to the high-price events.
4 and 10 January 2008 and 18 and 19 February 2008	South Australia	25	Extreme temperatures in South Australia led to record high demand. AGL Energy's strategy of offering a significant proportion of generation capacity at prices above $5000 per MWh, and a limit placed on the flow of electricity on the interconnectors between Victoria and South Australia, contributed to the high-price events.
31 December 2007	South Australia	1	Extreme temperatures in South Australia led to near-record demand. A multiple unplanned network outage near Melbourne led to network constraints being invoked that forced electricity flows from Snowy and South Australia into Victoria. The forced exports from South Australia further tightened supply and raised prices in that region.
4 November 2007	Queensland	2	A planned network outage limited generation capacity in southwest Queensland. The outage, combined with rebidding by Stanwell power station and an unplanned outage at the Swanbank power station (unit E), caused high prices in Queensland.
22 October 2007	New South Wales	1	NEMMCO applied incorrect limits to manage the power system during a planned network outage in New South Wales. As a result, imports from Queensland into New South Wales and generation at several New South Wales power stations were significantly reduced.

Sources: AER, *Spot prices greater than $5000/MWh—New South Wales 22 October 2007*, 2007; AER, *Spot prices greater than $5000/MWh—Queensland 4 November 2007*, 2007; AER, *Spot prices greater than $5000/MWh—South Australia 31 December 2007*, 2008; AER, *Spot prices greater than $5000/MWh—South Australia 4 and 10 January and 18 and 19 February 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Snowy 26 January 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Queensland 30 January and 7 February 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Queensland 22 to 23 February 2008*, 2008; AER, *Spot prices greater than $5000/MWh—South Australia 15 to 17 March 2008*, 2008; AER, *Spot prices greater than $5000/MWh—Victoria and Snowy 17 March 2008*, 2008.

15 Energy Reform Implementation Group, *Energy reform: The way forward for Australia—a report to the Council of Australian Governments*, 2007.

Box 2.2 International electricity prices

Wholesale electricity prices in Australia rose significantly during 2007 towards levels experienced in many overseas markets. However, over the longer term, electricity prices in Australia have been low relative to liberalised markets overseas. The principal reason is Australia's access to low-priced fuel such as brown and black coal.

Table 2.5 compares annual load-weighted average wholesale prices in the NEM with selected international markets on a calendar year basis. Comparisons across markets should be made with caution. Various factors can affect wholesale market outcomes, including:

- market design (for example, the use or absence of a capacity market)
- the stage of the investment cycle
- overcapacity that may be a legacy from previous regulatory regimes
- meteorological conditions
- fuel costs and availability
- exchange rates
- requirements under a carbon trading scheme
- regulatory intervention.

Prices in the Nord Pool (an electricity market linking Norway, Sweden, Finland and Denmark) increased significantly over the period from 1999 to 2006. Heavily reliant on hydroelectric power, prices in this region have a strong negative correlation with rainfall levels. The sharp price increase in 2006 resulted from a combination of factors, including increased load, rising fuel costs, low reservoir levels, unavailability of nuclear plants in Sweden and the introduction of a carbon trading scheme in Europe. In 2007, an increase in hydroelectric generation led to prices falling by almost 43 per cent.[16]

The Electric Reliability Council of Texas operates a wholesale market that supplies electricity to 75 per cent of Texas. Price fluctuations in this market—as in Canada's Alberta market—largely reflect changes in the cost of natural gas. The fall in average

Table 2.5 **Average wholesale prices in selected markets ($A per megawatt hour)**

	NEM				INTERNATIONAL				
YEAR	Qld	NSW	Vic	SA	Nord Pool (Scandinavia)	Alberta (Canada)	ERCOT (Texas)	NEMS (Singapore)	PJM (USA)
2007	72	76	70	65	46	75	67	73	74
2006	28	35	38	45	81	95	73	111	71
2005	27	41	28	37	48	76	95	86	83
2004	37	53	32	47	49	57	61	66	60
2003	24	30	25	29	64	69	68	82	64
2002	52	45	35	38	47	52	47	n/a	57
2001	37	36	40	52	40	92	n/a	n/a	71
2000	56	39	40	65	20	n/a	n/a	n/a	53
1999	46	24	24	60	22	n/a	n/a	n/a	53

n/a, not available.

Nord Pool, a market between Norway, Sweden, Finland and Denmark; ERCOT, Electric Reliability Council of Texas; NEMS, National Electricity Market of Singapore; PJM, Pennsylvania–New Jersey–Maryland Pool.

Notes:

1. Prices for Alberta are unweighted.
2. The PJM includes a capacity market.
3. Rounded annual volume-weighted price comparison based on calendar year data. Price conversions to Australian dollars based on average annual exchange rates.

Sources: Nord Pool; PJM; Electricity Market Company of Singapore; ERCOT; Alberta Electric System Operator.

16 Nord Pool Spot AS, *2007 Annual review*, 2008, p. 15.

prices in Alberta in 2007 was due to increased production from lower-cost generators.[17]

The Pennsylvania–New Jersey–Maryland pool (PJM) links generating facilities in 12 states in the USA. Coal is the major fuel source for electricity in the market (accounting for over 55 per cent of generation), with uranium (34 per cent) and gas (8 per cent) also being significant.[18] While PJM prices in 1999 were comparable to those in Queensland and South Australia, there was a significant increase in PJM prices to 2005. Average prices moved above $80 per MWh in 2005 following a 40 to 50 per cent increase in oil and gas costs.[19]

Unlike the NEM, the PJM operates a capacity market in conjunction with the energy market. Capacity markets provide an additional source of revenue for generators and so reduce revenue requirements in the energy market. Accordingly, spot prices in the PJM would likely be higher in the absence of a capacity market. Adjusting for this difference, table 2.5 may understate the price discount in the NEM compared to the PJM.

The National Electricity Market of Singapore (NEMS) commenced operating in January 2003. With close to 97 per cent of electricity generation fuelled by either oil or gas, prices in the NEMS have been substantially above those experienced in the NEM.[20] In 2007, average energy prices in the NEMS fell from 2006 levels, despite a 19 per cent increase in fuel oil prices. This may reflect greater competition from two new gas generators that became operational in April 2007.[21]

17 Alberta Electric System Operator, *2007 Annual report*, 2008, p. 22.

18 PJM Market Monitoring Unit, *2007 State of the market report*, 2008, p. 14.

19 PJM Market Monitoring Unit, *2005 State of the market report*, 2006.

20 Energy Market Company of Singapore, *2006 Market report to the National Electricity Market of Singapore*, 2007.

21 NEMS Market Surveillance and Compliance Panel, *Annual report 2007*, 2008, p. 10.