
# 2 NATIONAL ELECTRICITY MARKET


Generators in the National Electricity Market sell electricity to retailers through wholesale market arrangements whereby the dynamics of supply and demand determine prices and investment. The Australian Energy Regulator monitors the market to ensure 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 across 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 270 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 geographic 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.

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

The NEM supplies electricity to almost nine million residential and business customers. In 2008–09 the market generated around 208 terawatt hours (TWh)[2] of electricity, with a turnover of $9.4 billion (table 2.1).

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

| | |
|---|---|
| Participating jurisdictions | Qld, NSW, Vic, SA, Tas, ACT |
| NEM regions | Qld, NSW, Vic, SA, Tas |
| Registered capacity | 47 418 MW |
| Number of registered generators | 268 |
| Number of customers | 8.8 million |
| NEM turnover 2008–09 | $9.4 billion |
| Total energy generated 2008–09 | 208 TWh |
| National maximum winter demand 2008–09 (11 June 2009) | 32 094 MW[1] |
| National maximum summer demand 2008–09 (29 January 2009) | 35 551 MW |

TWh, terrawatt hour; MW, megawatt; NEM, National Electricity Market.
1. The maximum historical winter demand of 34 422 MW occurred in 2008.
Sources: AEMO; ESAA, *Electricity gas Australia*, Melbourne, 2009, 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 an end use customer can 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 Australian Energy Market Operator (AEMO) has managed the operation of the NEM since 1 July 2009.[3] The Australian Energy Regulator (AER) monitors the market to ensure participants comply with the National Electricity Law and Rules.

The design of the NEM reflects the physical characteristics of electricity:

- Supply must meet demand at all times because electricity cannot be economically stored. Coordination is thus required 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 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 4). Both market designs require the market operator to be informed of all sales so 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, either in the spot or ancillary services[5] markets or by trading hedge instruments in financial markets[6] outside NEM arrangements.

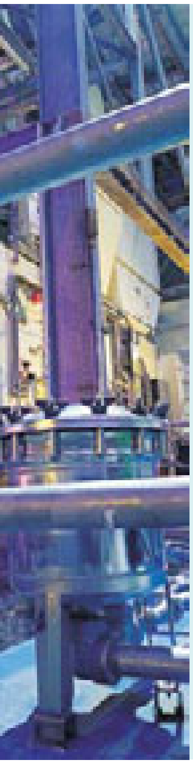
2 One TWh is equivalent to 1000 gigawatt hours (GWh), 1 000 000 megawatt hours (MWh) and 1 000 000 000 kilowatt hours (KWh). One TWh is enough energy to light 10 billion light bulbs with a rating of 100 watts for one hour.

3 The National Electricity Market Management Company managed the market until 1 July 2009.

4 The market price cap will increase from $10 000 per MWh to $12 500 per MWh on 1 July 2010.

5 AEMO operates a market for frequency control ancillary 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.



### 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.

In 1996 Queensland, New South Wales, the ACT, Victoria and South Australia agreed to pass the National Electricity Law, which provided the legal basis to create the NEM. The market commenced in December 1998.

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 Snowy region was abolished on 1 July 2008 through a regional boundary change. 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.

## 2.2.1 Market operation

As market operator, AEMO coordinates a central dispatch process to manage the wholesale spot market. The process matches generator supply offers to demand in real time: AEMO 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.

Some generators bypass the central dispatch process, including some wind generators,[7] those not connected to a transmission network (for example, embedded generators) and those producing exclusively for their own use (such as in remote mining operations).

## 2.2.2 Demand and supply forecasting

AEMO 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 customers each have relatively predictable patterns, including seasonal demand peaks related to extreme temperatures. Using data such as historical load (demand) patterns and weather forecasts, AEMO develops 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. In response to the growth in wind generation and its impact on the forecasting process, AEMO recently introduced a wind forecasting system in the NEM. It aims to provide better forecasts that will improve dispatch efficiency, pricing, and network and security management.

7 From 31 March 2009 new wind and other intermittent generators must register under the new classification of 'semi-scheduled generator'. The generators must participate in the central dispatch process, including by submitting offers and by limiting their output if requested by AEMO.

## 2.2.3 Central dispatch and spot prices

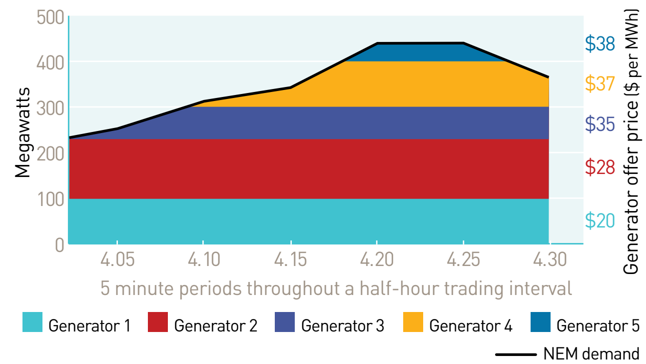
Market supply is based on the offers of generators to produce particular quantities of electricity at various prices for each of the 5 minute dispatch periods in a day. Generators must lodge offers ahead of each trading day. They can change their offers (rebid) at any time subject to those bids being in 'good faith'.

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

To determine which generators are dispatched, AEMO stacks the offer bids of all generators in ascending price order for each 5 minute dispatch period. It 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 5 minute interval is the offer price of the highest (marginal) priced megawatt (MW) of generation that must be dispatched to meet demand. In figure 2.1, the demand for electricity at 4.15 is about 350 MW. To meet this level of demand, generators 1, 2 and 3 are fully dispatched and generator 4 is partly dispatched. The dispatch price (or marginal price), therefore, is \$37 per MWh. 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 per MWh, which drives up the price to that level.

**Figure 2.1**
**Illustrative generator offers (megawatts) at various prices**




Source: AEMO.

A wholesale spot price is determined for each half-hour period (trading interval) and is the average of the 5 minute dispatch prices during that interval. In figure 2.1, the spot price in the 4.00–4.30 interval is about \$37 per MWh. This is the price that all generators receive for their supply during this 30 minute period, and the price that market customers pay for the electricity they use in that period. A separate spot price is determined for each region, accounting for 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. If, for example, suitable metering arrangements are available, then 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).

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

## 2.3 Demand and capacity

Annual electricity consumption in the NEM rose from under 170 TWh in 1999–2000 to 208 TWh in 2008–09 (figure 2.2a). The entry of Tasmania in 2005 accounted for around 10 TWh. 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 2.2b shows seasonal peaks have risen nationally, from around 26 gigawatts (GW) in 1999 to over 35 GW in 2009. The volatility in the summer peaks reflects variations in weather conditions from year to year.

Figure 2.2a

**National Electricity Market electricity consumption**

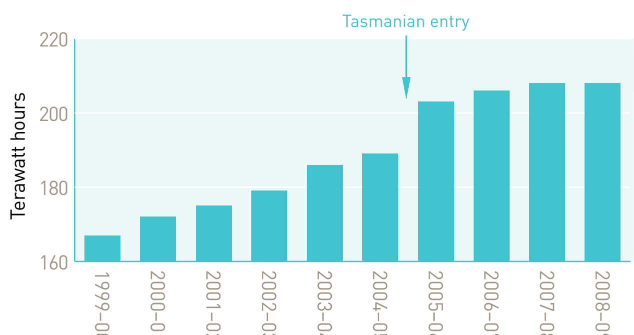
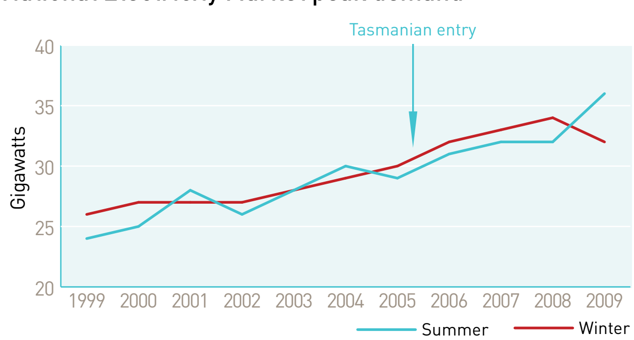



Figure 2.2b

**National Electricity Market peak demand**




Sources: AEMO; AER.

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

Figure 2.3 compares seasonal peak 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 across the regions

The NEM promotes efficient generator use by allowing trade in electricity among 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. On a day of peak electricity demand in South Australia, for example, low cost baseload power from Victoria may provide a competitive alternative to South Australia's high cost peaking generators. The NEM means AEMO can dispatch electricity from lower cost regions and export it to South Australia until the technical capacity of the interconnectors is reached.

Figure 2.4 shows annual electricity consumption and trade across the regions in 2008–09. It also shows each region's generation capacity factor (the use of local generation capacity). The NEM's interregional trade relationships are also reflected in figure 2.5, which shows the net trading position of the regions since the NEM commenced.

Table 2.2 **Annual electricity consumption in the National Electricity Market (terawatt hours)**

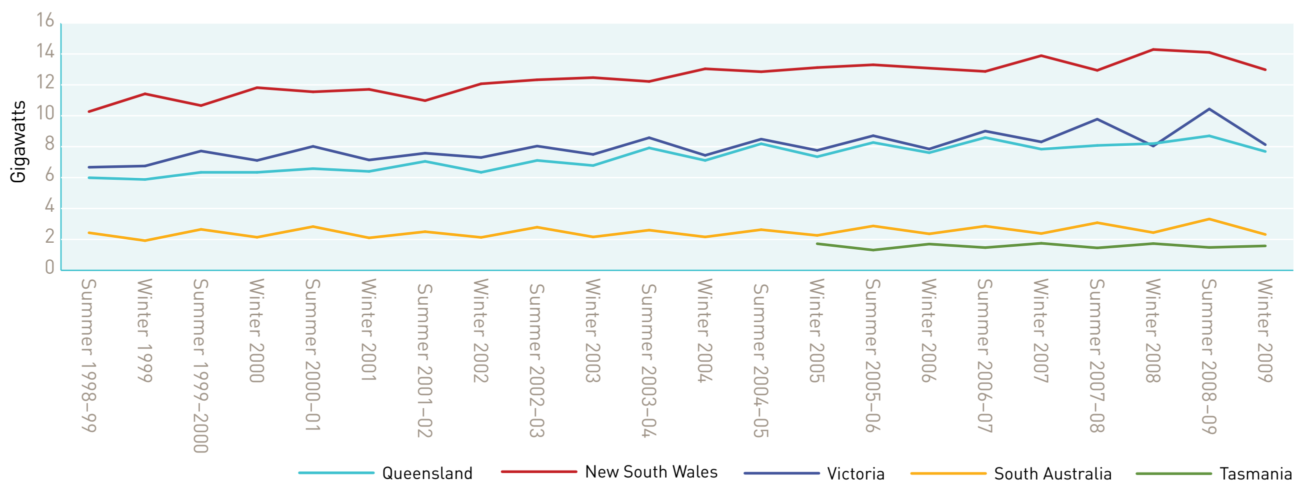
| | QLD | NSW | VIC | SA | TAS[1] | SNOWY[2] | NATIONAL |
|---|---|---|---|---|---|---|---|
| 2008–09 | 52.6 | 79.5 | 52.0 | 13.4 | 10.1 | | 207.9 |
| 2007–08 | 51.5 | 78.8 | 52.3 | 13.3 | 10.3 | 1.6 | 208.0 |
| 2006–07 | 51.4 | 78.6 | 51.5 | 13.4 | 10.2 | 1.3 | 206.4 |
| 2005–06 | 51.3 | 77.3 | 50.8 | 12.9 | 10.0 | 0.5 | 202.8 |
| 2004–05 | 50.3 | 74.8 | 49.8 | 12.9 | | 0.6 | 189.7 |
| 2003–04 | 48.9 | 74.0 | 49.4 | 13.0 | | 0.7 | 185.3 |
| 2002–03 | 46.3 | 71.6 | 48.2 | 13.0 | | 0.2 | 179.3 |
| 2001–02 | 45.2 | 70.2 | 46.8 | 12.5 | | 0.3 | 175.0 |
| 2000–01 | 43.0 | 69.4 | 46.9 | 13.0 | | 0.3 | 172.5 |
| 1999–2000 | 41.0 | 67.6 | 45.8 | 12.4 | | 0.2 | 167.1 |

1. Tasmania entered the market on 29 May 2005.
2. The Snowy region was abolished on 1 July 2008. Electricity consumption formerly attributed to Snowy is now reflected in the New South Wales and Victorian data.

Source: AEMO.



Figure 2.3
**Seasonal peak demand in the National Electricity Market**




Sources: AEMO; AER.

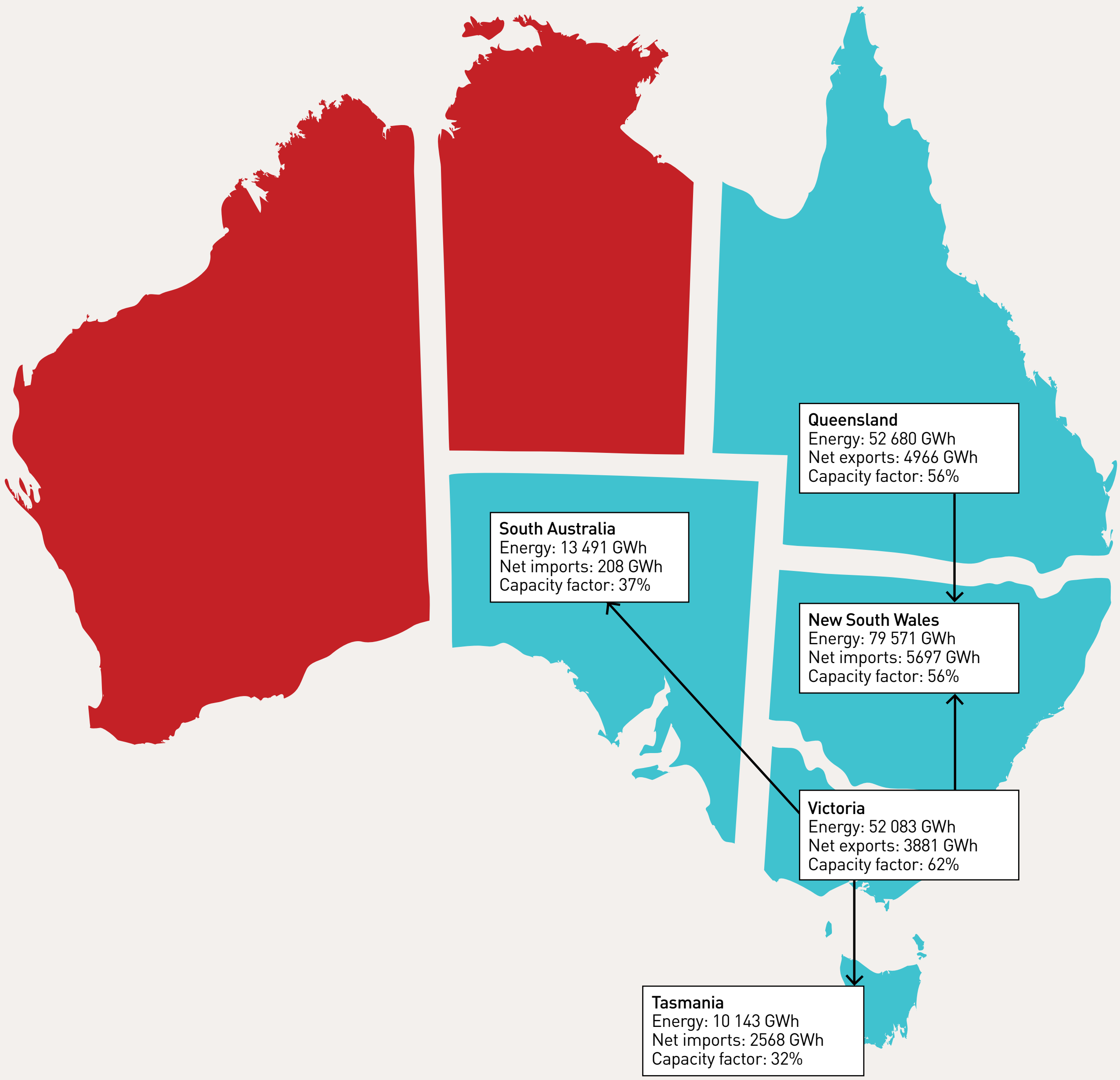
Figures 2.4 and 2.5 show:

- 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 was importing over 10 per cent of its electricity requirements from 2002–03 to 2006–07, but this rate fell to around 7 per cent in 2007–08 and 2008–09.
- Victoria is a net exporter because it has substantial low cost baseload capacity.[10] This is reflected in the region's 62 per cent capacity factor—the highest for any region. In 2008–09 Victorian net electricity exports were equivalent to around 8 per cent of the state's consumption. Victoria tends to import mainly at times of peak demand when its regional capacity is stretched.

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

10 The Victorian region gained additional hydroelectric peaking capacity on 1 July 2008 when the Murray generator was transferred from the Snowy region to Victoria.

Figure 2.4
**Trade flows across National Electricity Market regions, 2008–09**




GWh, gigawatt hour.

Notes:

'Energy' refers to electricity consumption.

'Capacity factor' refers to the proportion of local generation capacity in use.

Sources: AEMO; AER.

Figure 2.5

Interregional trade as percentage of regional energy consumption


Sources: AEMO; AER.

- Queensland's installed capacity exceeds its peak demand for electricity by around 3400 MW, making it a significant net exporter. Net exports from Queensland rose steadily from 2001–02, reaching around 13 per cent of the state's electricity consumption in 2006–07. Net exports fell to slightly below 10 per cent of consumption in 2008–09.
- 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. New investment in generation—mostly in wind capacity—has significantly reduced South Australia's net imports since 2005–06. The state was a net exporter for the first time in 2007–08, but recorded net imports of around 2 per cent of electricity consumption in 2008–09.
- Tasmania has been a net importer since its interconnection with the NEM in 2006. It imported over 25 per cent of its electricity requirements in 2008–09, partly because drought constrained its ability to generate hydroelectricity.

## 2.4.1 Market separation

The NEM central dispatch process 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, minor disparities across regional prices is normal. 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 an unplanned outage occurs. The availability of generation plant and the bidding behaviour of generators can also contribute to transmission congestion.

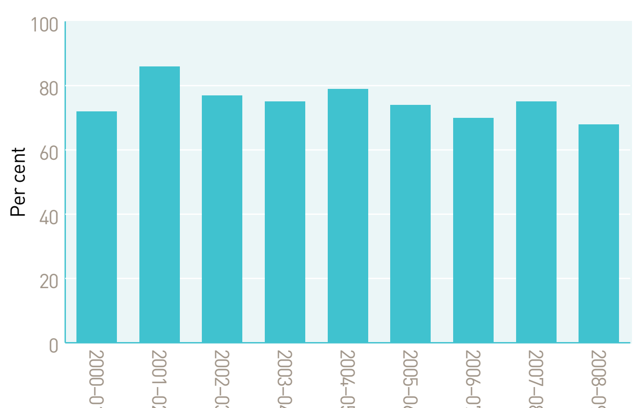
When congestion restricts a high demand region's ability to import electricity, prices in that region may spike. If, for example, low cost Victorian electricity is constrained from flowing into South Australia on a day of high demand, then more expensive South Australian generation—for example, local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

The NEM is considered aligned when electricity can flow freely among all regions. There may still be minor price differences across regions due to loss factors that occur in the transport of electricity. Figure 2.6 indicates the mainland NEM regions operated as an 'integrated' market—with price alignment across the regions—for around 70 per cent of the time in 2008–09. This was the lowest rate of market alignment since the NEM commenced.

While the extent of alignment indicates how effectively the market is working, external factors such as lightning and other extreme weather may restrict interconnector flows. More generally, significant investment would be needed to remove all congestion, even under normal operating conditions. Research by the AER indicates the economic costs of transmission congestion are relatively modest given the scale of the market (see section 5.7).

Figure 2.6

**Regional price alignment in the National Electricity Market as a percentage of trading hours**




Note: Excludes Tasmania.

Sources: AEMO; AER.

## 2.4.2 Settlement residues

When there is price separation across 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. These settlement residues accrue to the market operator (AEMO).

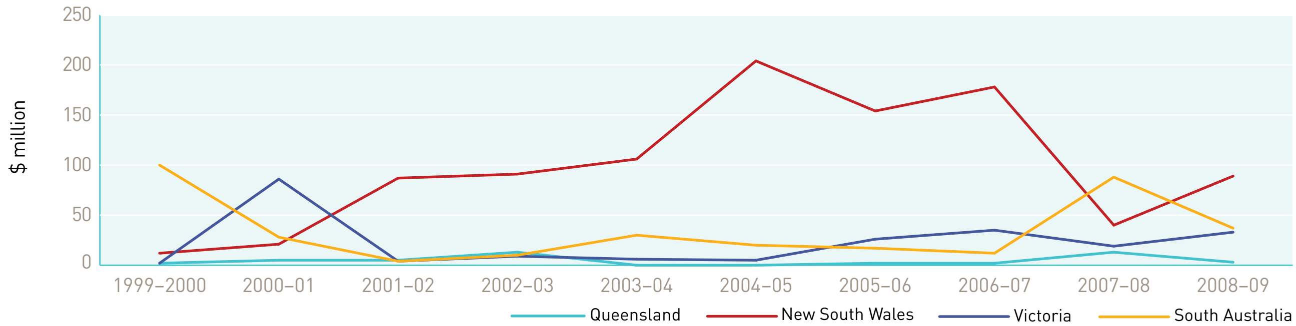
Figure 2.7 charts the annual accumulation of interregional settlement residues in each region. There is some volatility in the data, reflecting that a complex range of factors can contribute to price separation—for example, the availability of transmission interconnectors and generation plant, weather 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 range 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. New South Wales settlement residues fell by around 75 per cent in 2007–08 as a result of more benign market conditions, but rose in 2008–09. High prices on 31 October 2008 contributed around half of the region's settlement residues for the year.

Conversely, South Australian residues increased from a low base to almost \$88 million in 2007–08 as a result of record summer prices in the region. While South Australian summer prices remained high in 2008–09, settlement residues fell closer to historical levels as summer prices also moved higher in Victoria. As net exporters, Queensland and Victoria tend not to accumulate large settlement residue balances.

Price separation creates risks for parties that contract across regions. To offer a risk management instrument, AEMO holds quarterly auctions to sell the rights to future residues. Section 5.7.3 explains the auction process.

Figure 2.7
Settlement residues in the National Electricity Market




Note: AEMO does not auction residues from Basslink, which is a market network service provider that earns income by arbitraging price differences between Tasmania and Victoria.

Sources: AEMO; AER.



## 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 across regions as a result of losses in transportation and transmission congestion, which sometimes restricts interregional 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 2.8 charts quarterly volume weighted average prices since the NEM commenced, while table 2.3 sets out annual volume weighted prices. Figure 2.9 provides a more detailed snapshot of weekly prices since January 2007.

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. Drought, record peak demands and other factors led to average prices rising to record levels in 2006–07 and 2007–08.

Average prices in 2008–09 eased in all regions other than Tasmania (table 2.3). This reflected wetter conditions in parts of eastern Australia and, in 2009, the mildest winter on record in New South Wales, Victoria and South Australia. The milder winter temperatures drove lower winter peak demands in most regions. Combined winter peak demand for the NEM in 2009 was 32 094 MW—the lowest since 2006. This led to lower average winter prices in all mainland regions compared with last winter's averages, ranging from 26 per cent lower in New South Wales to 38 per cent lower in Victoria. In Tasmania, the average winter price increased by almost 70 per cent as a result of extreme price events in June 2009.

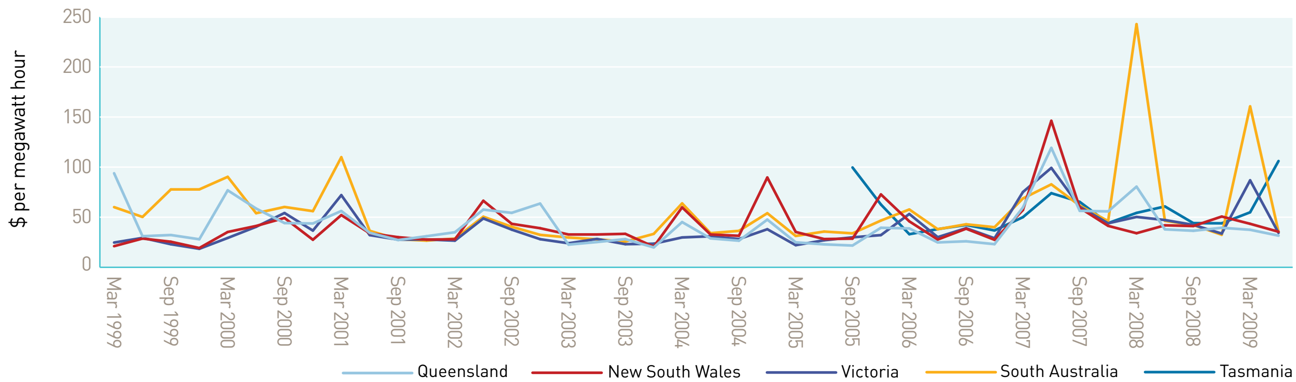
For the year overall, Queensland recorded its lowest prices since 2005–06. While prices fell sharply in South Australia, they remained high relative to those in other mainland regions.

Despite relatively benign market conditions, several extreme price events occurred in the first six months of 2009. These events occurred mostly in South Australia and Tasmania:

> Spot prices in South Australia exceeded $5000 per MWh on 27 occasions in the early months of 2009. These events typically occurred on days of extreme temperatures, which led to a tight supply–demand balance. The bidding strategies of AGL Energy on most of these occasions led to South Australian prices rising to near the market cap of $10 000 per MWh.

Figure 2.8

Quarterly volume weighted average prices—National Electricity Market




Sources: AEMO; AER.

**Table 2.3** Weighted average spot electricity prices ($ per megawatt hour)

| | QLD | NSW | VIC | SA | TAS[2] | SNOWY[3] |
|---|---|---|---|---|---|---|
| 2008–09 | 36 | 43 | 49 | 69 | 62 | |
| 2007–08 | 58 | 44 | 51 | 101 | 57 | 31 |
| 2006–07 | 57 | 67 | 61 | 59 | 51 | 38 |
| 2005–06 | 31 | 43 | 36 | 44 | 59 | 29 |
| 2004–05 | 31 | 46 | 29 | 39 | | 26 |
| 2003–04 | 31 | 37 | 27 | 39 | | 22 |
| 2002–03 | 41 | 37 | 30 | 33 | | 27 |
| 2001–02 | 38 | 38 | 33 | 34 | | 27 |
| 2000–01 | 45 | 41 | 49 | 67 | | 35 |
| 1999–2000 | 49 | 30 | 28 | 69 | | 24 |
| 1999[1] | 60 | 25 | 27 | 54 | | 19 |

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

Source: AEMO.

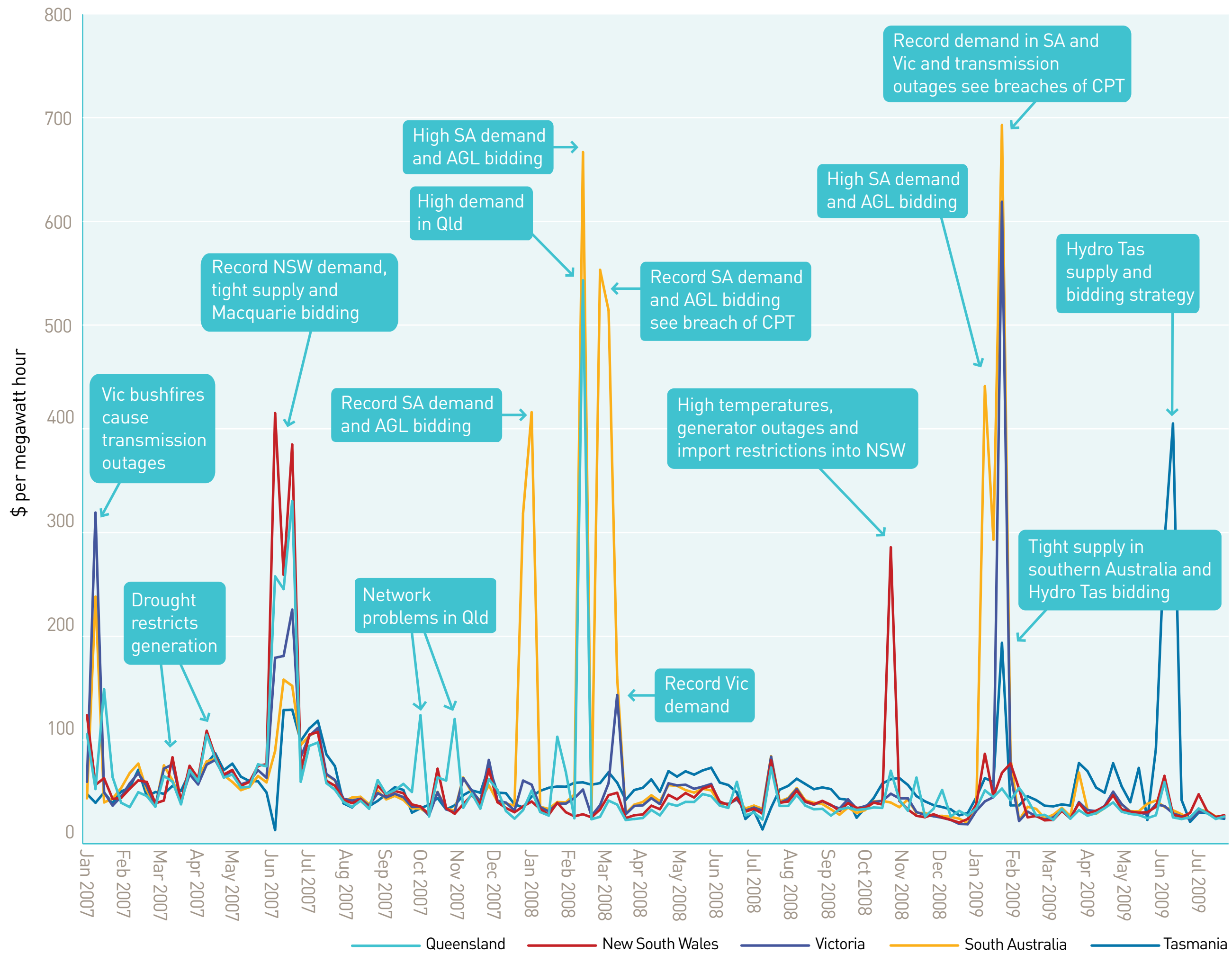
AGL Energy owns the Torrens Island power station, which accounts for 40 per cent of South Australia's generation capacity. Transmission limits on importing electricity from Victoria mean, under certain conditions, that AGL Energy can price a significant proportion of its capacity at around the market cap and be guaranteed some of the high-priced capacity will be dispatched. On 28 January 2009, for example, AGL Energy bid around 800 MW of capacity—around 65 per cent of Torrens Island's summer capacity rating—at close to the price cap of $10 000 per MWh.

> On 28 and 29 January 2009 extremely hot weather in South Australia and Victoria resulted in record demand. When combined with unplanned reductions in generation capacity and the outage of the Basslink interconnector on 29 January, this led to extreme prices and customer interruptions in both regions. The sustained high spot prices led to the cumulative price threshold being breached and pricing being administered in both regions for several days. The extreme temperatures also contributed to high prices in Tasmania on 29 and 30 January, with three spot prices in excess of $5000 per MWh.

- In June 2009 the spot price in Tasmania exceeded $5000 per MWh on 13 occasions. Reductions in output by Hydro Tasmania of its non-scheduled generation (mini hydro), in conjunction with its bidding strategy for the rest of its portfolio, was the significant driver in the majority of these outcomes.

In addition to high energy prices, Tasmania's frequency control ancillary services were very highly priced in April 2009. The prices of some services reached $5000 per MW for 13 hours over 1 April to 3 April, compared with typical prices of around $2 per MW. Further sustained high price events occurred through to 17 April.

Figure 2.9
**National Electricity Market—average weekly prices**




AGL, AGL Energy; CPT, cumulative price threshold; Macquarie, Macquarie Generation; Hydro Tas, Hydro Tasmania.

Note: Volume weighted prices.

Sources: AEMO; AER.


Origin Energy

## 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. Electricity demand can rise swiftly on a hot day, for example. 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 2.9 indicates 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. The main indicator of the incidence of extreme price events is the number of trading intervals during which the price is above $5000 per MWh (figures 2.10 and 2.11)

The AER draws on its market monitoring to publish weekly reports on market outcomes and more detailed reports when the electricity spot price exceeds $5000 per MWh.

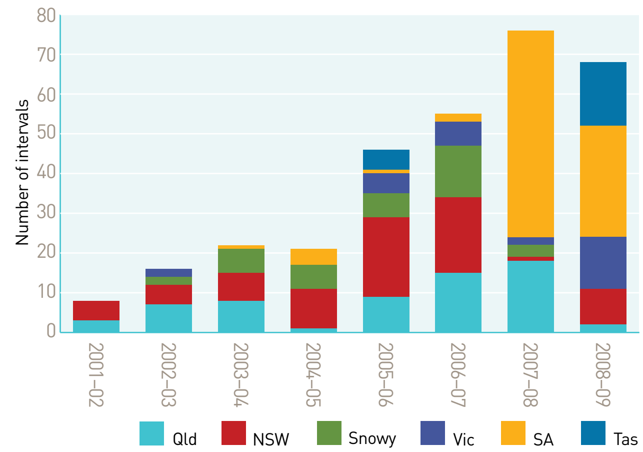
The incidence of trading intervals with prices above $5000 per MWh has increased since the NEM commenced (figure 2.10). The number of events rose significantly from 21 in 2004–05 to 76 in 2007–08. There were 68 events in 2008–09, of which 27 occurred in South Australia and 16 occurred in Tasmania in the first six months of 2009. The bidding behaviour of AGL Energy and Hydro Tasmania respectively contributed to many of these price outcomes. Figure 2.11 sets out the data on a quarterly basis.

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

**Figure 2.10**

**Trading intervals above $5000 per megawatt hour—National Electricity Market**




Note: Each trading interval is a half hour.

Sources: AEMO; AER.

Table 2.4 summarises key features of extreme price events in 2008–09, noting the regions in which they occurred and indicating causes. The most common causes were:

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

On one occasion, an error by AEMO contributed to high spot prices.

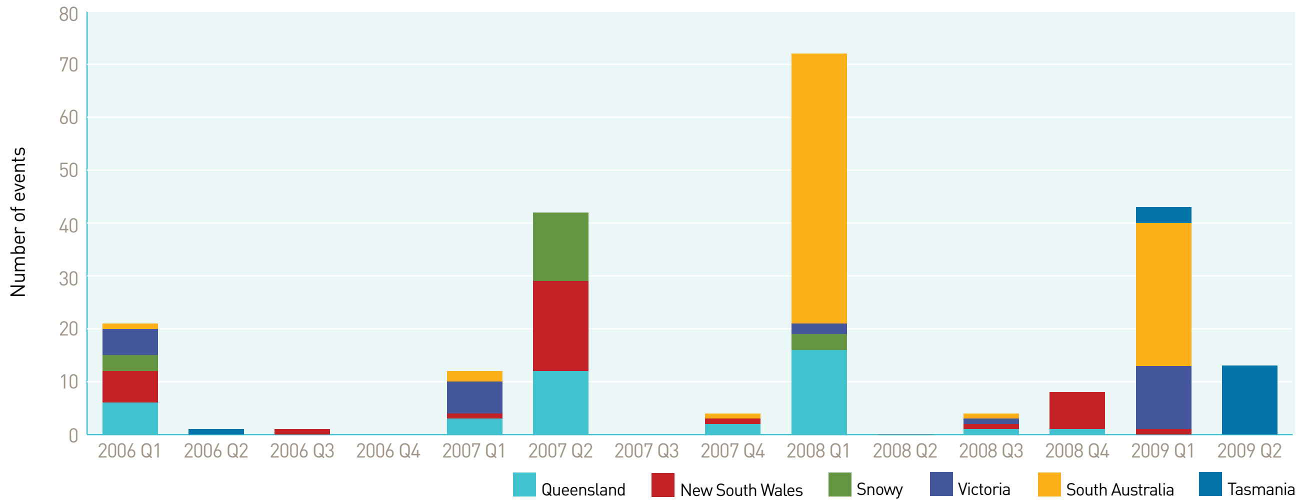
Price spikes can have a material impact on market outcomes. If prices approach $10 000 per MWh for just three hours in a year, the average annual price may rise by almost 10 per cent. Generators and retailers typically hedge against this risk by taking out contractual arrangements in financial markets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

Figure 2.11

Trading intervals above $5000 per megawatt hour (quarterly)—National Electricity Market




Sources: AEMO; AER.

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. In 2009 AEMO estimated 195 MW of committed demand-side response in the NEM, with a further 559 MW of less firm capacity available.[11]

In April 2009 the Australian Energy Market Commission released a draft review of demand-side participation in the NEM.[12] It found the current framework allows for efficient participation, but also found a few minor barriers that a change in the Electricity Rules will address.

At the small customer level, the Council of Australian Governments agreed in 2007 to a progressive rollout of 'smart' electricity meters (where the benefits outweigh costs) to encourage demand-side response (see section 6.8.2).

## 2.7 Market investigations

The AER monitors activity in the spot market to screen for issues of non-compliance with the Electricity Rules. In addition to reporting on all extreme price events in the NEM, it conducts more intensive investigations where this is warranted.

In 2008 the AER launched separate investigations into whether Stanwell (a Queensland generator) and AGL Energy (in relation to its South Australian generators) acted 'in good faith', as contemplated under the Rules, when they rebid capacity during periods of high prices in early 2008. While bidding capacity at high prices is not a breach of the Rules, generators are required to make capacity offers and any rebids in 'good faith.' In its investigation findings published on 12 May 2009, the AER found that AGL Energy's bidding was not in breach of the Rules.

The AER investigation into the rebidding behaviour of Stanwell led to it instituting proceedings in the Federal Court, Brisbane. The AER has alleged that several of Stanwell's rebids of offers to generate electricity on 22 and 23 February 2008 were not made in 'good faith'. The AER is seeking orders including declarations, civil penalties, a compliance program and costs. The matter has been set down for trial in June 2010.

11 AEMO, *Electricity statement of opportunities*, Melbourne, 2009, p. 67.

12 AEMC, *Demand-side participation in the National Electricity Market, draft report*, Sydney, April 2009.

Table 2.4 **Price events above $5000 per megawatt hour—National Electricity Market, 2008–09**

| DATE OR PERIOD | REGIONS | NO. OF EVENTS | CAUSES IDENTIFIED BY THE AER |
|---|---|---|---|
| 23 July 2008 | New South Wales, Queensland, Victoria and South Australia | 4 | Unplanned outages of two Hazelwood to Loy Yang transmission lines in the LaTrobe Valley (Victoria) left only one line in operation between Loy Yang and Tasmania and the rest of the market. Very high frequency control ancillary services were required to manage this. In addition, generation at Loy Yang was constrained and exports from Tasmania via Basslink were reduced to zero. |
| 31 October 2008 | New South Wales | 7 | High temperatures in Sydney led to above forecast demand. Around 4300 MW of generation was unavailable (mostly unplanned) and import capability into New South Wales was also lower than forecast. |
| 20 November 2008 | Queensland | 1 | Unplanned reductions in Queensland generator availability occurred, in combination with low import capability and higher than forecast demand. Millmerran Energy Trader and Stanwell Corporation then rebid low priced capacity at close to the price cap. |
| 13 January 2009 | South Australia | 8 | AGL's bidding behaviour, high temperatures and high demand at a time of lower than forecast import capability. This required the dispatch of high priced generation. |
| 15 January 2009 | New South Wales | 1 | Temperatures in western Sydney reached 43 degrees, leading to record summer demand. In addition, around 2100 MW of New South Wales generation was unavailable and import capability was reduced as a result of planned network outages. New South Wales generators reacted to the tight supply–demand balance by rebidding capacity into higher price bands. |
| 19 January 2009 | South Australia | 6 | For five trading intervals, high demand caused by extreme temperatures led to the dispatch of high priced capacity. Rebidding by AGL Energy shifted a significant amount of required capacity from prices below $101 per MWh to the price cap. Dispatch of this capacity set the spot price for two and a half hours.<br><br>In the other interval, an incorrect input into the dispatch process led to the spot price exceeding $5000 per MWh. |
| 28–29 January 2009 | South Australia and Victoria | 24 | Record demand (due to extreme weather in South Australia and Victoria), combined with unplanned reductions in generation capacity and the unplanned outage of the Basslink interconnector on 29 January, required the dispatch of high priced generation. The extreme conditions led to customer interruptions in both regions on 29 January. The sustained high prices led to the cumulative price threshold being breached and pricing being administered in both regions for several days. |
| 29–30 January 2009 | Tasmania | 3 | On 29 January one spot price exceeded $5000 per MWh when Hydro Tasmania rebid a significant amount of capacity from below $1600 per MWh to above $5000 per MWh. On 30 January two spot prices exceeded $5000 per MWh as a result of tight supply in southern Australia combined with high priced generation offers in Tasmania. |
| 31 March 2009 | South Australia | 1 | An unplanned outage at South Australia's largest generator—Northern power station—led to the dispatch of high priced generation. |
| 1 June 2009 | Tasmania | 1 | Hydro Tasmania rebid a significant amount of capacity from prices below $300 per MWh to prices above $9000 per MWh. It can set the spot price in Tasmania, even at moderate levels of demand. |
| 10–19 June 2009 | Tasmania | 12 | Eleven events occurred when Hydro Tasmania made sudden and repeated reductions in the output of its non-scheduled generators, requiring the dispatch of other generation in its portfolio. At the same time, Hydro Tasmania made a step change in the amount of capacity it was offering at prices above $5000 per MWh. The other event occurred when Hydro Tasmania bid a significant amount of capacity at above $5000 per MWh for the trading interval.<br><br>The sustained high prices caused a breach of the cumulative price threshold for the first time ever in Tasmania, and led to administered pricing for several days. |