Energy Reform
The way forward for Australia

Supporting Appendices

A report to the Council of Australian Governments by the Energy Reform Implementation Group

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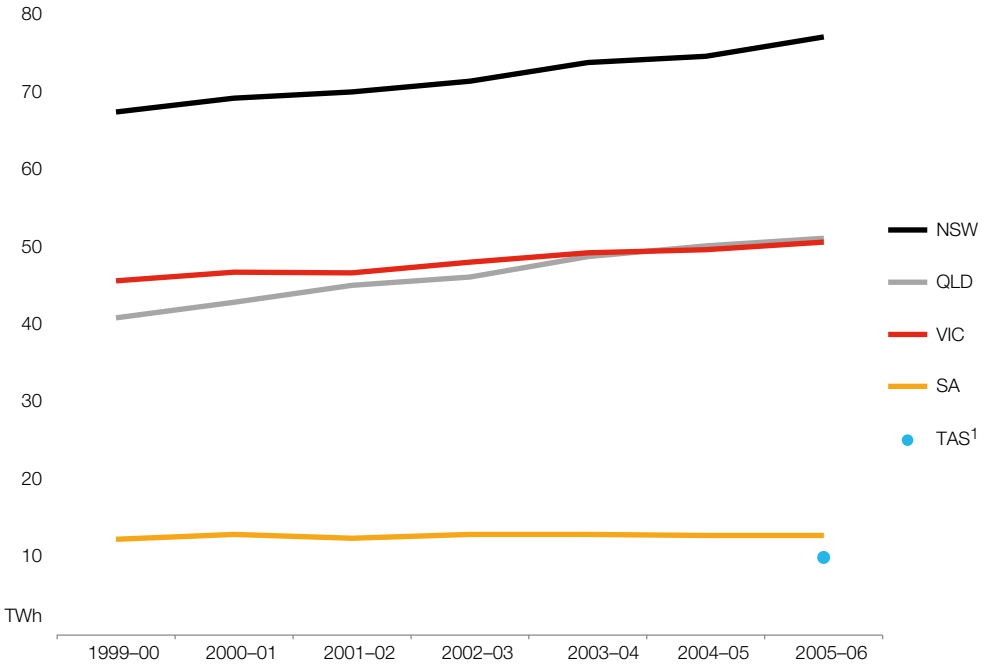
Appendices

Electricity market: its main elements

Electricity consumption

Since the beginning of the NEM, electricity consumption has steadily increased in New South Wales, Victoria and Queensland. During this time, consumption in South Australia has remained relatively constant. Figure 1 depicts these trends.

1 Electricity consumption in NEM regions



1 Tasmania entered market May 29,2005.
Source: NEMMCO 2006

Residential customers comprise the largest share of consumption (27.8 per cent) followed by commercial customers (24.2 per cent), aluminium smelting (13.6 per cent) and other manufacturing industries (12.2 per cent). The breakdown of consumption by sector is set out in table 1.

Today, the NEM supplies electricity to more than 8 million Australian customers on an interconnected national grid that runs through Queensland, New South Wales, the Australian Capital Territory, Victoria and South Australia. Outside the NEM, almost one million customers are supplied electricity in Western Australia (929,918) and around 76,000 customers in the Northern Territory (ESAA 2006).

1 Electricity Consumption by Sector

	%
Residential	27.8
Commercial	24.2
Aluminium smelting	13.6
Other manufacturing	12.2
Other metals	11.7
Mining	8.5
Transport and storage	1.0
Agriculture	0.9

Source: ESAA 2006

More than $7 billion of energy is traded through the NEM per year (ESAA 2006).

Retail prices

Prior to the introduction of energy market reforms, the prices set by electricity businesses were heavily regulated. Following the opening of the generation and retail sectors to competition, the industry has had more freedom to set its prices. At the same time, competition has put downward pressure on prices.

Since the NCP reforms the average price of electricity has fallen 19 per cent (PC 2005). Indeed, Australia has some of the lowest retail electricity prices among the International Energy Agency (IEA) member countries.

For industrial customers, Australia had the second lowest ex-tax retail prices in the IEA in 2002. Prices in Australia are 38 per cent below the average retail price among IEA member countries. For household customers, Australian prices were the third-lowest in 2002, behind New Zealand and Norway. Australian prices were 31 per cent below the average retail price among IEA member countries (IEA, 2005).

These low prices, by international standards, reflect Australia's abundant coal and natural gas resources and competitive electricity market. To this end, the IEA states that Australia has one of the most transparent and competitive electricity markets in the world (IEA, 2005).

Retail price controls

Although the wholesale price of electricity is determined by market forces, the price that consumers pay for electricity is subject to regulatory control, particularly for residential customers. This regulation has generally taken the form of price controls to ensure that financially vulnerable consumers have access to affordable electricity services as part of a broader social policy agenda.

Retail price caps were considered by governments to be a necessary transitional measure to provide a safety net for consumers following the disaggregation of the electricity sector and the introduction of competition. Governments implemented retail price controls to protect consumers who are unable or unwilling to participate in the competitive market.

These 'safety net' arrangements were introduced as a transitional measure to provide a regulatory discipline on the market as a proxy for market discipline.

Wholesale prices

Wholesale electricity prices vary across the jurisdictions of the NEM. In 2004-05, Victoria had the lowest volume-weighted average price ($28.80 MWh) while South Australia had the highest prices (average volume weighted price $39.29 MWh).

By international standards, electricity prices remain low in Australia. Based on IEA analysis of pool prices over 2003 and 2004, the average Australian pool price was 44 per cent below Nordpool, 37 per cent below Germany and 46 per cent below the pool price in the Pennsylvania-New Jersey-Maryland pool price (IEA, 2005). These low prices have raised concerns about whether prices are sufficient to signal new investment in baseload capacity.

Table 2 shows the average wholesale prices across the NEM for 2004-05. However, since this trading period significant baseload generation capacity has been built in Queensland, which is reflected in Queensland now having the cheapest wholesale price in the NEM.

2 National Electricity Market Trading Summary, 2005-06

Region	Unit	NSW	Vic	QLD	SA	Snowy	Tas
Total energy	TWh	77.3	50.8	51.3	12.9	0.5	10.0
Energy value	$ bil	3.3	1.8	1.6	0.6	0.01	0.6
Average demand	MW	8762	5774	5844	1459	52	1136
Maximum demand	MW	13188	8679	8295	2873	161	1676
Minimum demand	MW	5397	3780	4024	768	<1	769
Maximum price	$/MWh	9739	9134	9157	7758	7440	7386
Minimum price	$/MWh	8	-14	-327	1	0	5
Average price[1]	$/MWh	43	36	31	44	29	59

1 Volume weighted
Source: NEMMCO market data

Demand forecasts

Driven by an increase in economic growth, inter alia, the forecast for energy demand is expected to rise gradually over the medium to long term.

ABARE predicts that energy demand will increase on average 2.1 per cent annually to 2030. With this estimated 2.1 per cent growth rate, electricity generation is expected to increase by 73 per cent from 237 TWh in 2003-04 to 409 TMh by 2029-30 (ABARE 2005).

The Electricity Supply Association of Australia (ESAA) predict that demand will increase by 20 per cent between 2004-05 and 2013-14 in the NEM regions, with the largest growth coming in Queensland, New South Wales and Victoria (ESAA, 2006).

Supply forecasts

ABARE forecasts that electricity generation capacity will increase by an average rate of 2.1 per cent a year from 2003-04 to 2029-30 to meet future growth in demand.

Electricity generated by coal as a fuel source is forecast to continue to provide the bulk of Australia's electricity requirements. In 2003-04, coal-fired generation plants accounted for 76.7 per cent of the country's total electricity production (ABARE 2005). The dominance of coal as a fuel source is due to its relative abundance, particularly on the eastern seaboard, and low cost.

Natural gas has steadily increased its role as a fuel source for electricity generation over the past decade. This increase has been mainly in South Australia, Western Australia and the Northern Territory, where coal is relatively more expensive. In the other states, natural gas predominately fulfils a peaking role, due to its cost.

In 2003-04, natural gas generation plants accounted for 14.3 per cent of Australia's generation capacity. This share of overall capacity has increased steadily over the past decade and is forecast to continue to grow strongly.

In contrast to the moderate growth expected in coal fired generation, electricity generation from natural gas is expected to grow at an annual rate of 3.8 per cent a year by 2029-30. This growth in gas fired generation capacity is expected to be particularly strong in the medium term, increasing at a rate of 4.4 per cent a year (ABARE 2005).

The Energy Supply Association of Australia (ESAA) estimates that natural gas as a share of the electricity generation market will double between now and 2030. The ESAA reports that more than 11,200 MW of gas-fired generation capacity is currently under construction or under consideration (ESAA 2006).

This growth is expected to be particularly strong in Queensland and New South Wales, largely due to their respective gas schemes. The outlook for gas is also positive in Western Australia, Northern Territory and Tasmania due to their lack of coal resources.

Electricity market overview: contestable sectors

Generation

Electricity is generated by a mix of public and privately owned businesses. In all states except Victoria and South Australia generation assets are predominately government owned.

In New South Wales, the government owns the three largest generators (Macquarie Generation, Delta and Eraring), which account for over 80 per cent of the market for generation capacity in that state. In addition, these three generators account for around 30 per cent of the market for generation capacity in the NEM.

In Queensland, generation capacity is largely supplied by the government owned generators (Tarong, Stanwell and CS Energy), which together account for around 70 per cent of the generator market in Queensland. Queensland also has several public/private generators (Callide C) and fully private generators (Milmerran).

The Victorian electricity generation sector is fully privatised and has the most diverse portfolio of generation assets in the NEM. In contrast to New South Wales and to a lesser extent Queensland, Victoria has a highly competitive generation sector. Table 4 sets out the market share of generators in Victoria.

The South Australian generation sector is also characterised by private ownership of assets. However, in contrast to Victoria the level of ownership concentration is particularly high with NRG Flinders and TRUenergy having a market share of over 67 per cent. Table 5 sets out the market share of generators in South Australia.

In Western Australia, recent reforms have split up the previously vertically integrated public utility, Western Power, into separate generation, retail, network and regional businesses. The generation business, Verve Energy, generates around 60 per cent of state's current electricity requirements, with private generators supplying the remainder.

In the Northern Territory, nearly all electricity is supplied by the state-owned vertically integrated Power and Water Authority.

The NEM also includes generation capacity from Snowy Hydro, which is jointly owned by the NSW, Victorian and Commonwealth governments.

Trends in the generation sector

In states with private ownership, there has been a rapid evolution of industry structure through merger and acquisition activity. In the generation sector this has resulted in significant re-aggregation of generation assets in Victoria and South Australia.

This merger and acquisition activity has significantly increased concentration in the Victorian and South Australian generation sector. However, generation in these states remains less concentrated than in New South Wales (treating the three government owned businesses as separate business).

The market share of generation portfolios in each of the NEM jurisdictions is shown in table 3, while figure 2 shows generator market share for the entire NEM.

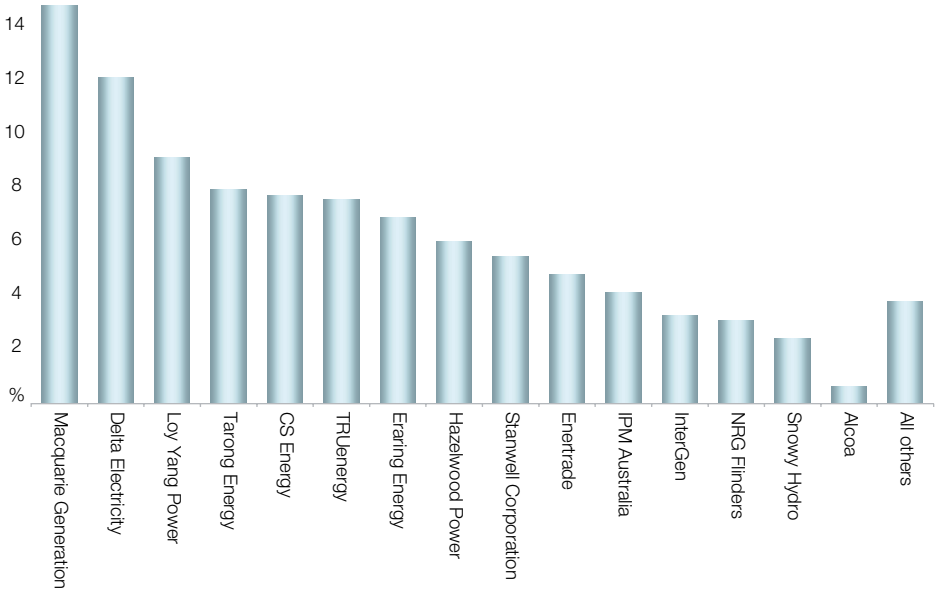
3 Generation market share, 2005

	GWh	%		GWh	%
NSW[1]			**Victoria**		
Macquarie Generation	28 141	36.4	Loy Yang Power	17 426	32.1
Delta Electricity	23 087	29.8	TRUenergy	11 577	21.3
Eraring Energy	13 105	16.9	Hazelwood Power	11 436	21.1
Import from Qld	4 759	6.2	IPM Australia	7 847	14.5
Snowy Hydro	4 537	5.9	Import from Snowy	1 539	2.8
Import from Victoria	1 625	2.1	Alcoa	1 170	2.2
National Power	1 072	1.4	Energy Brix	1 140	2.1
Sithe Energy	1 028	1.3	Ecogen	1 097	2.0
			AGL	603	1.1
			Import from NSW	217	0.4
			Import from SA	97	0.2
			Alinta	74	0.1
			Eraring Energy	38	0.1
			Snowy Hydro	22	<0.1
			All others*	448	0.8
Total	**77 353**	**100**	**Total**	**54 730**	**100**
Queensland			**South Australia**		
Tarong Energy	15 157	27.2	NRG Flinders	5 885	45.4
CS Energy	14 711	26.4	TRUenergy	2 857	22.1
Stanwell Corporation	10 409	18.7	Import from Victoria	2 518	19.4
Enertrade	9 168	16.4	International Power	1 108	8.5
InterGen	6 219	11.1	Origin Energy	565	4.4
Import from NSW	85	0.2	AGL	23	0.2
Origin Energy	48	0.1	Infratil Energy	1	<0.1
Total	**55 798**	**100**	**Total**	**12 958**	**100**

1. Snowy region is included in NSW

Source: ESAA 2006

2 Generator market share in the NEM



Source: ESAA 2006

Retail

The retail electricity market comprises sales of electricity by retailers to end use customers. Within the area covered by the NEM, the retail market is partly competitive and partly operates on a regulated basis.

Full retail contestability (FRC) has been implemented in all regions in the Australian retail market to varying degrees. FRC allows consumers to choose their retailer. However, it does not eliminate the regulated tariffs that the default retailer must provide.

As retail price caps are retained, residential customers in markets that have FRC may still continue to purchase electricity from their default retailer, for pre-existing prices that continue to be regulated. But under FRC such customers have a choice. They may decide to purchase electricity from another retailer under a competitive retail price contract or opt to remain on a franchised load at fully regulated tariffs.

FRC has been introduced for all consumer classes in New South Wales, Victoria, South Australia and the Australian Capital Territory.

FRC is yet to be introduced for residential customers in Queensland (2007), Tasmania (2010) and the Northern Territory (2010). In Western Australia, the threshold for FRC was reduced in 2005 to include small to medium sized industrial customers[1].

In Victoria and South Australia, the introduction of FRC has facilitated a competitive market for the delivery of retail services. This is reflected in the number of new entrants and the high customer churn rates in these states, which are generally higher than 20 per cent (VENCorp, ESCOSA 2006).

In the other states, governments retain ownership of retail assets and have been more cautious about deregulating supply for household customers. These states have yet to see the emergence of vigorous competition in the retail sector.

However, the Queensland Government has recently announced the public sale of its electricity retail business. This should promote a more competitive retail sector.

Trends in the retail sector

In recent years several trends have become evident in the retail electricity sector. These include: the emergence of a significant number of new entrants in the competitive private retail markets of Victoria and South Australia; the trend toward increased vertical integration between retailers and generators; and the separation of retail and distribution activities.

In contrast to the generation sector, the number of retailers operating in the electricity sector is increasing. The introduction of full retail competition in Victoria and South Australia has seen the establishment of a number of new retailer businesses and a significant number of customers changing their retail service provider.

The retail sector has been moving toward greater vertical integration between retailers and generators. This merger activity, which is fundamentally different from the initial market

[1] Customers consuming more than 50 MWh are contestable in WA. WA contestability tranches are based on the average yearly demand rather than total annual consumption as per the other states.

structure envisaged by governments, indicates a trend toward a market structure consisting of vertically integrated generator/retailer businesses. In many cases, however, the integration is partial rather than 100 per cent .

Vertical integration between generation and retail businesses is a commercial response to the high level of risk in the electricity market and the largely inverse risks between generators and retailers. This difference in risk provides a partial natural hedge that makes at least partial vertical integration attractive. This trend has also been an emerging issue in other liberalised electricity markets.

A key trend in recent years has been the market driven separation of retail and distribution assets. This separation has been driven, in part, by the interest shown in regulated assets by infrastructure funds. These funds are attracted to the stable and secure returns that regulated assets offer.

Electricity market overview: regulated sectors

Transmission

Transmission is defined to mean the transport of electricity from the production source to large end users and distribution businesses. Electricity is transported through transmission networks that stretch across eastern and southern Australia (the NEM).

The NEM electricity transmission network has interconnections between Queensland, New South Wales, South Australia, Victoria, the ACT and Tasmania. Within the NEM there are currently six separate jurisdictions: one each for each member state and territory, but with the ACT included in NSW and the Snowy Hydro region being a jurisdiction in its own right.

Separate transmission networks exist in Western Australia and the Northern Territory.

Transmission networks are regulated in recognition of their natural monopoly characteristics which confer on the owner the ability to extract monopoly rents.

The transmission assets which comprise the NEM have an asset value currently of around $9.5 billion. In addition, transmission operators have committed to invest between $4 billion and $5 billion over the next five years to meet demand growth and to replace aged assets (ETNOF 2006).

In each jurisdiction there is one transmission network entity which owns and operates the transmission network. In Victoria (SP Ausnet) and South Australia (ElectraNet), private businesses carry out these functions. In the other states, government owned businesses own and operate the transmission network.

Transmission prices are on average around 7 per cent to 8 per cent of the total average delivered price of electricity (ETNOF 2006).

Trends in the transmission sector

The structure of the electricity industry has changed significantly over the past decade, which has changed the way transmission businesses perform their duties. Prior to the establishment of the NEM, transmission system operation and dispatch was conducted by regional transmission system operators in a vertically integrated business. These businesses were generally government owned.

Under this model, operational decisions affecting, inter alia, investment levels and the management of risks, were handled internally within the firm within a specified geographic area. Generally, these geographic boundaries coincided with State boundaries. Risk management was delivered through spare capacity in generation and transmission assets. This spare capacity was seen as the primary inefficiency in the pre-reform electricity sector.

Electricity market reform, and in particular the establishment of the NEM, transformed the electricity sector. Central to the reforms was the desire by governments to structurally separate monopoly and contestable elements to promote competition and greater efficiency.

The network sectors were subject to regulation and, in the case of transmission assets, structurally separated from the contestable elements of the market. Decisions that were once made in a centrally co-ordinated way within vertically integrated businesses are now being made by independent regulated businesses operating in specific geographic areas with the interconnected NEM region.

The increase of independent, de-centralised decision making in generation and retail, driven by competitive forces, has been the primary driver of efficiency gains to date.

The gains in the contestable sectors have only been possible through the structural reform of the industry. However, these reforms have created real challenges for the transmission sector. The decentralised nature of the post-reform electricity market has made decision making more complex and the regulatory environment more challenging.

Table 4 sets out the ownership arrangements for transmission business.

4 Transmission businesses in the Australian electricity market

Transmission businesses	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
ElectraNet				•				
Power and Water Corporation							•	
Powerlink			•					
SP AusNet		•						
Transend Networks						•		
TransÉnergie	•	•	•	•				
TransGrid	•							•
Western Power Corporation					•			

Source: ESAA 2006

Distribution

Electricity distribution businesses deliver electricity to over 12 million homes and businesses across Australia through approximately 800,000 kilometres of electricity lines. These electricity distribution networks are valued at around $28.7 billion. Expected capital expenditure on distribution over the next five years is approximately $14.6 billion (ENA 2006).

Following the energy market reforms of the past decade, distribution businesses were either 'stapled' together with a retail business and sold to the private sector, as was the case in Victoria; operated under long term lease arrangements, as was the case in South Australia; or retained under the government ownership model which applied in the other states. Under the last of these models, distribution and retail assets were also stapled together. However, in Queensland, the separation of ownership of distribution and retail businesses has also been a feature of recent policy decisions.

In all States and Territories, mandatory ring fencing requirements have been introduced to ensure that jointly-owned distribution and retail businesses operate at arms-length.

Table 5 sets out the arrangements for distribution businesses in the Australian electricity market.

5 Distribution businesses in the Australian electricity market

Distributors	NSW	VIC	QLD	SA	WA	TAS	NT	ACT
ActewAGL								•
AGL		•						
Aurora Energy						•		
CitiPower		•						
Country Energy	•							
Energex			•					
EnergyAustralia	•							
Ergon Energy			•					
ETSA Utilities				•				
Integral Energy	•							
Power and Water Corporation							•	
Powercor Australia		•						
SP AusNet		•						
United Energy Distribution		•						
Western Power Corporation					•			

Source: ESAA 2006

Trends in the distribution sector

The distribution sector has undergone significant change over the past 15 years. This change has been characterised by the separation of distribution and retail from the previously vertically integrated publicly owned monopolies, which in turn has led to increased consolidation of distribution assets. These changes have been driven by a number of commercial forces.

The introduction of FRC, has increased the risks to which retailers are exposed. Given the different risk profiles for retail and distribution assets – the nature of which requires quite different business approaches – it no longer made sense for business to cover both activities within a single organisation.

During this time there has also been strong and growing interest in regulated assets from infrastructure/superannuation funds, which are attracted to the stable and secure (almost bond-like) cash flow returns that these assets offer. The different risk profiles of retail and distribution assets requires quite different business approaches and has ultimately seen the capital market drive separation of these assets at an ownership and operational level.

This market driven separation has in turn facilitated greater aggregation of network assets. This is particularly evident in Victoria and South Australia where the market is allowed to operate more freely than other states.

In Victoria, this move towards greater aggregation was driven, in part, due to the structure of the industry immediately after privatisation. The previously vertically integrated public utility, the State Electricity Commission, was initially split into five electricity networks. These businesses were far smaller on an international basis than similar stand alone entities overseas. To achieve the scale efficiencies available through common ownership of network assets, merger and acquisition activity began to gather pace.

This level of horizontal aggregation reflects scale efficiencies available through the operation of energy networks. These businesses are regulated monopolies and therefore concerns about the exercise of market power generally do not apply.

In the states where these assets are predominately provided by government owned businesses the same commercial drivers and disciplines are not apparent. However this appears to be changing, for Queensland at least, with the government recently announcing the sale of its electricity retail businesses, Energex and Ergon (as well as its gas distribution business, Allgas).

There has also been a trend toward cross ownership of electricity and gas assets. While this type of activity effectively increases market concentration it does not lessen competition or efficiency in the sector as these assets are subject to price and access regulation.

Financial markets

Financial markets provide a mechanism for market participants to facilitate risk transfer and price discovery, both of which enable them to manage the risks inherent within their businesses and compete with each other to deliver electricity at the lowest possible cost to consumers.

Financial markets are important in supporting competitive market structures in a wide range of commodity markets, including electricity and gas. Two distinct electricity and gas financial markets have emerged in Australia, the over-the-counter (OTC) market and the exchange traded market.

Australia's energy financial markets comprise the traded markets for forward instruments for risk management, speculation, and arbitrage opportunities as well as energy capital markets which underpin energy investments throughout Australia. The spot market is an integral part of the energy financial market as it provides cash flow pay-off's which are inextricably linked to the forward market through arbitrage opportunities.

State by State market arrangements

The fully privatized Victorian electricity industry has three main retailers (TRUenergy, Origin Energy and AGL), four distribution businesses (CKI-Powercor, Alinta, AGL and SPI Ausnet), a single transmission business (SP Ausnet) and five major generators (International Power, TRUenergy, Loy Yang Power, Ecogen and Southern Hydro). There have also been significant new entrants into the contestable generation and retailing sectors.

The South Australian electricity industry was fully privatised by 2000. Its previous government owned corporation, ETSA Corporation, was disaggregated. There is now one distributor (ETSA Utilities) and one transmission company (Electranet). Immediately following privatisation only one retailer was created, which AGL acquired. However, since then there has been significant market entry at the retail level. Private generation interests include International Power, NRG, and TRUenergy. AGL and Origin have also built significant new generation capacity in the last few years.

Reforms to the Queensland electricity industry have resulted in the present industry profile comprising government ownership of two distribution and retail businesses (Energex and Ergon), a transmission business (Powerlink) and four generation businesses (Enertrade, CS Energy, Stanwell and Tarong Energy). Private ownership in the Queensland electricity market comprises Intergen and NRG in the generation sector. The Queensland Government is currently in the process of privatising its retail businesses.

The New South Wales electricity industry has also undergone a series of reforms to structurally separate the previous vertically integrated service provider. However, unlike Victoria and South Australia, and, to a lesser extent, Queensland, government ownership remains a defining feature of the electricity industry in New South Wales.

Individual suppliers include four distribution and retail businesses (Energy Australia, Integral, Country Energy and Australia Inland) a transmission business (Transgrid) and three generation businesses (Delta Electricity, Macquarie Generation and Eraring Energy). There are also two smaller privately owned generators and Snowy Hydro, which is jointly owned by the New South Wales, Victorian and Commonwealth Governments.

In Western Australia, the state-owned vertically integrated utility, Western Power Corporation, was disaggregated into four separate businesses as part of recent energy market reforms in that State. These reforms structural separated Western Power into separate retail (Synergy), generation (Verve Energy), networks (Western Power) and regional power (Horizon Power) corporations.

The Tasmanian Government has also disaggregated its former vertically integrated supplier, but has retained government ownership. Tasmania became linked to the NEM in 2006 with the commissioning of BassLink.

Electricity in the Northern Territory is primarily supplied by the State-owned utility, Power and Water Corporation. Around 97 per cent of electricity is generated from gas, which is sourced from the Amadeus Basin gas fields. Customers with annual loads of more than 750 MWh are able to choose their retailer.

The intra-NEM regions

Historically, State and Territory governments owned and operated Australia's electricity supply assets and sold electricity at regulated prices. During the 1990s, governments implemented reforms to deregulate and restructure the industry as noted at the start of this chapter.

Building on the fact that the country's population is concentrated in the States on the eastern seaboard, and that some of the State transmission systems were already interconnected, governments created a 'national' (really eastern and southern) electricity market that shared resources and widened trade options. This meant building additional interconnectors between state networks and centralising administration and operation of the market and the transmission elements of the power system.

Today, the NEM operates in Queensland, New South Wales, the Australian Capital Territory, Victoria, South Australia and Tasmania. The seven regions (jurisdictions) of the NEM mainly follow State boundaries, with the Australian Capital Territory included in the New South Wales region, and the area surrounding the Snowy Mountains Hydro-Electricity Scheme being a region in its own right.

States outside the NEM

Western Australia

The Western Australian electricity industry is characterised by a small and geographically dispersed load with minimal grid development. In 2002, the WA market accounted for 6.9 per cent of total generation (ESAA, 2005). The isolated nature of the Western Australian electricity market has prevented it from being connected to the NEM.

The Western Australian Government has recently implemented wide ranging reforms to its electricity sector. These reforms have been developed to address structural issues and are aimed at ensuring the Western Australian energy market continues to move towards a competitive industry. The following sets out the key areas of reform

A key element of WA's reforms is the move to disaggregate the State owned vertically integrated electricity utility, Western Power Corporation, into four new businesses; retail (Synergy), generation (Verve Energy), networks (Western Power) and regional power (Horizon Energy) combined with measures to encourage new capacity and competition into the market via the imposition of a cap on the expansion of Verve Energy beyond 3000 MW, restrictions on Verve Energy and Synergy vertically integrating and new vesting arrangements which will require Verve Energy and Synergy to source alternative retailers and suppliers. These measures are intended to encourage increased competition in the

generation and retail sectors by creating opportunities for new entrants to compete with existing market participants.

The recent certification of Western Australia's State based Electricity Access Regime as effective under the National Access Regime is expected to improve network access for new entrants. It is expected that certification will enhance regulatory certainty through the use of a common regulatory framework for Western Australia's electricity network.

The Western Australian Government has also put in place institutional arrangements for the efficient operation of the energy market. This includes the establishment of an independent regulator, the Economic Regulatory Authority, in January 2004 to carry out key regulatory functions and licensing arrangements for electricity and gas, and the establishment of the Independent Market Operator in December 2004, to administer and operate the wholesale electricity market.

A wholesale electricity market for Western Australia became operational on 21 September 2006. The wholesale market is designed to provide for the trading of electricity and capacity credits through bilateral trades and to create a short-term energy market and balancing mechanism. A key element of the wholesale market will be a Reserve Capacity Mechanism, which is designed to ensure sufficient generation capacity and demand side management services are available to meet system requirements.

Northern Territory

The Northern Territory electricity market is characterised by a small and geographically dispersed load with minimal grid development. In 2002, the Northern Territory accounted for approximately 0.9 per cent of national generation capacity. Customers with annual loads of more than 750 MWh are able to choose their retailer.

Electricity in the Northern Territory is primarily supplied by the State-owned utility, Power and Water Corporation. Around 97 per cent of electricity is generated from gas, which is sourced from the Amadeus Basin gas fields.

The gas market

There is a growing relationship between gas and electricity markets. In the market for electricity, gas is both a supply-side competitor (investment in gas production and pipelines competes with electricity generation and transmission) and often a very close, if not perfect, demand-side substitute in many end-use applications. On the supply side, it is also a key input into electricity production itself (e.g. for "peak" and "intermediate" power generation).

Therefore, a level playing field between electricity and gas is important in achieving efficient energy outcomes. This includes competitive neutrality between the commodities themselves and appropriate locational signals for related financial markets.

Structural reform of Australia's energy markets

Governments agreed to structurally reform the electricity and gas markets during the 1990s as part of the National Competition Policy Reforms. The genesis for these reforms was the 1993 "National Competition Policy Report by the Independent Committee of Inquiry" (Hilmer Report).

Central to these reforms was the separation of contestable and natural monopoly elements of the markets to facilitate more efficient, lower cost, delivery of electricity to customers. To this end, market mechanisms as well as regulatory reforms were introduced to improve the efficiency of both electricity pricing and investment in new electricity infrastructure.

These reforms led to the creation of the National Electricity Market (the NEM) in the eastern states. Within this market, individual markets govern supply in both wholesale and retail sectors, and there is an open access regime in place for the transmission and distribution networks. These networks are subject to price regulation in recognition of the potential for market power abuse.

By 2001, New South Wales, Victoria, Queensland, South Australia and the Australian Capital Territory had structurally separated their previously vertically integrated electricity monopolies into a series of business entities, separating out generation, transmission, and distribution and retailing functions. Structural separation for distribution and retailing was implemented through ring-fencing arrangements[2].

Tasmania and Western Australia have recently followed suit and structurally separated their state owned electricity businesses into monopoly networks and competing generators and retailers. Given the small size of its market relative to efficient supply scale, the costs of structural reform of the Northern Territory's power assets were estimated to outweigh the benefits of reform, so such reforms have not been pursued to date.

Victoria and South Australia took structural separation a step further and privatised their electricity assets (in the case of South Australia under long term lease arrangements). In Victoria, the distribution businesses were 'stapled' [3] with a retailer within defined geographic areas of operation prior to privatisation. In South Australia, the distribution business was privatised under a long term lease arrangement and the retail business was sold separately with the sector opened up to competing retailers.

Governance of energy markets

One of the most recent developments in the electricity industry has been in relation to the governance arrangements that apply to the industry. This reform has resulted in the establishment of three new bodies, the Ministerial Council on Energy (the MCE), the Australian Energy Regulator and the Australian Energy Market Commission.

The aim of these reforms was to separate the responsibility for policy, rule-making and rule-enforcement functions while still maintaining adequate accountability through the political process.

[2] The ring-fenced business is required to ensure legal and operational separation of their business from other related business. This ensures behavioural separation of retail and distribution businesses.

[3] Retail and distribution businesses in Victoria and South Australia were established in a single entity and the retail and distribution functions were subject to ring-fencing requirements.

Ministerial Council on Energy

Under the Australian Energy Market Agreement, the Ministerial Council on Energy (MCE) is responsible for the national policy and governance oversight for the Australian energy market.

The MCE, comprising Australian and State/Territory Government Energy Ministers, provides the high-level policy direction under which the AER and AEMC operate but does not engage directly in the day-to-day operation of the market or in the conduct of the regulators.

The regulatory framework

The Australian Energy Regulator (AER) is responsible for economic regulation and compliance at a national level and is responsible for enforcing the provisions contained in the National Electricity Law and National Electricity Rules. The AER currently performs this role in the wholesale electricity market and electricity transmission networks in the NEM. These functions will broaden to include the National Gas Law and National Gas Rules and responsibility for regulating retail and distribution prices.

Currently, State and Territory regulators are responsible for regulating of electricity retail and distribution functions within their jurisdiction. This includes responsibility for regulating retail prices and distribution charges.

The approaches taken by the various State and Territory regulators differ somewhat across jurisdictions. Subject to agreement by the individual jurisdictions, the responsibility for regulating electricity distribution and retail is scheduled to be transferred to the AER in 2008.

It is expected that this rationalisation of regulatory functions will then facilitate a single national approach to the regulation of the electricity sector.

The Australian Energy Market Commission

The Australian Energy Market Commission (AEMC) is responsible for rule making and energy market development. The AEMC's rule making function involves managing the rule change process and consulting and deciding on rule changes proposed by other parties. The market development function is performed by undertaking reviews of the electricity and gas market or on any matter that applies to the efficient operation of the NEM. The rule-making function does not involve initiating changes to the Rules or correcting other than minor or non-material errors.

Wholesale market and system operation: NEMMCO

The National Electricity Market Management Company (NEMMCO) is the system and market operator for the NEM. In carrying out these functions, NEMMCO is responsible for the day to day operation and administration of the power system and electricity spot wholesale market in the NEM and other support activities and is charged with responsibility for ensuring there is adequate supply to meet demand at all times.

Electricity produced by all generators goes into a common pool of electricity from which demand by consumers is drawn. The role of the NEMMCO, as system operator, is to ensure that balance is maintained between inflows and outflows at each point in time.

A single central dispatch process determines the merit order of dispatch of generation, with the lowest price generator being dispatch first subject to system constraints. This process is based on a five minute dispatch cycle and 30 minute trading intervals.

The NEM is an energy only market. The essential feature of an energy-only electricity market is that generators only receive payment for the electricity they produce. Their production is measured as sent-out energy by metering equipment at the point where the generators are connected to the network. In capacity markets, such as the Western Australian market, the system operator makes payments for capacity to supply electricity as well as for actual production undertaken.

The spot market is the market where generators are paid for the electricity they sell to the pool, and retailers pay for their electricity consumption. A spot price for wholesale electricity is calculated for each five minutes and the clearing/settlement price to match supply and demand is set every half hour (average of the five minute intervals) during the day. The spot price is particularly volatile and can vary from negative $1,000/MWh to $10,000/MWh.

All generation is referenced to a single point in each state – the regional reference node – and generators are paid according to amount of energy notionally delivered to this point.

6 Governance arrangements for energy market institutions

	ACCC	AER	AEMC	NEMMCO	IMO (WA)
Organisation type	Statutory authority	Statutory authority	Statutory authority	Not for profit corporation limited by guarantee with functions determined by statute.	Statutory body
Management arrangements and appointments process	Commissioners and associate commissioners appointed by the Commonwealth subject to consultation and majority support by states and territories	3 commissioners. Commonwealth appoints chair, states and territories appoint two commissioners	States and territories appoint two commissioners, one of whom is the chair, the Commonwealth appoints the third commissioner.	States and territories appoint one board member each. Commonwealth excluded from membership.	3 commissioners appointed by the minister
Funding arrangements	Australian Government, through annual appropriation	Australian Government through annual appropriation	Shared funding on a population basis by states and territories	Levy on NEM market participants. Annual auditing of accounts.	Market fees as approved by the Economic Regulatory Authority
Reporting	Annual report to the Treasurer for presentation to Parliament	Annual report to Treasurer for presentation to Australian Parliament	Annual report to SA minister for presentation to SA parliament and copies provided to all MCE ministers	Quarterly and annual financial statements and operating report to members (energy ministers)	Annual report to the minister for presentation to parliament
Legislated objectives and functions	The object of the TPA is to enhance the welfare of Australians through the promotion of competition and fair trading and provision for consumer protection.	Carry out functions conferred on it by law (TPA). Regulate the national electricity law and carry out economic regulation (National Electricity (SA) Act)	Rule making, market development and other functions as conferred by legislation (AEMC Establishment Act and National Electricity (SA) Act). AEMC must have regard to the market objective which is to "promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system"	To establish and conduct the NEM efficiently in accordance with the legislation, to promote the NEM with the objective of continually improving efficiency, and to coordinate system planning as specified in the legislation.	IMO administer market rules, operate reserve capacity mechanism & short term energy market, perform market settlement, develop & amend market rules, monitor & enforce rules. Rule changes must be consistent with market objective which includes: promotion of economic efficiency, encouraging competition, avoidance of discrimination according to technology, minimisation of the long term cost of energy, measures to manage electricity use.

Progress against Parer recommendations & MCE reforms

Governance and regulatory arrangements (Chapter 2)

Establish a national energy regulator to encompass the energy related roles of the Australian Competition and Consumer Commission (ACCC), National Electricity Code Administrator (NECA) and state and territory regulators (2.1, 2.2, 2.3).	Part done

» Australian Energy Regulator (AER) commenced on 1 July 2005.

» Roles of state and territory regulators have not yet been fully transferred. Powers have been conferred in relation to electricity generation and transmission (in all states and territories except WA and NT), but not yet for gas regulation. By 1 July 2007, powers are expected to be formally transferred for:

  – economic regulation of electricity distribution;

  – economic regulation of gas transmission; and

  – economic regulation of gas distribution.

» Powers in relation to the non-economic regulation of energy distribution and the regulation of energy retail activities are expected to transfer on 1 January 2008.

» The rulemaking role of NECA has been taken over by the Australian Energy Market Commission and the enforcement role has been taken over by the AER.

National Electricity Code and Gas Code change processes be changed to provide greater industry involvement and ownership of the process (2.4, 2.5, 2.6).	Done
Statutory committees be created to progress amendments (2.7, 2.8, 2.9, 2.10, 2.11).	Done

» The AEMC commenced on 1 July 2005.

» AEMC is responsible for rule making and market development functions for the electricity markets in all states, except WA and NT. Derogations constrain the AEMC's ability to change distribution revenue and pricing rules.

» The AEMC is expected to formally take over responsibility for gas transmission and distribution rule making and market development by 1 July 2007, taking over the roles currently performed by the Gas Code Registrar and the National Gas Pipelines Advisory Committee.

» The rule change process in the NEL and draft NGL allows any person to propose rule changes which must be considered by the AEMC and publicly consulted upon with industry.

The Ministerial Council on Energy (MCE) to be the single ministerial forum for energy market issues, with responsibility for providing policy oversight (2.12, 2.13).	Done

» The new governance arrangements give the MCE responsibility for providing broad policy direction and ensure no Ministerial involvement in the day-to-day operation of the market.

Changes be made to electricity network regulation: – to provide certainty on how gains from cost reduction will be shared over time and on how particular investments will be treated in the regulated asset base; – electricity distribution to be price, not revenue capped; – institute a nationally consistent bonuses and penalties regime for meeting defined network service provider service standards (2.14).	Part done

» The MCE's proposed rules concerning transmission regulation are designed to ensure that regulatory decisions are not transmission-centric, and that the most cost-effective investment options proceed. The capacity for cost reductions will in large part depend on final rule determinations by the AEMC, including the final determination (in late 2006) on Chapter 6A of the National Electricity Rules. Increased commercial negotiation is being encouraged under the proposed arrangements for transmission and distribution to deliver more competitive outcomes under the national regulatory framework.

» New rules for the regulation of distribution revenue are being developed. MCE working group officials have agreed that the AER will have discretion to apply both price and revenue caps across different distribution network services. There will also be provision for unregulated network services as well as service costs that fall under a negotiate/arbitrate regime.

» The AEMC's Chapter 6A transmission rules include a direction for the AER to develop incentives for transmission availability. This is to include incentives in relation to network availability that impacts on regional spot price outcomes. MCE working group officials have agreed that the new distribution rules will give the AER discretion to put DNSP revenue at risk under a network performance incentive scheme.

Establish a mandatory code of practice between distribution companies and embedded generators (2.15).	Part done

» A code of practice governing arrangements between distribution companies and embedded generators is being considered by the MCE working groups and a draft was released for consultation in early 2006. However, it is yet to be decided whether a code will be established given the development of the new national distribution and retail framework. If a code is established, it is likely to be empowered by the NER.

Electricity market mechanism and structure (Chapter 3)

NSW and WA should disaggregate generation portfolios and privatise electricity companies (3.1, 3.2, 3.3).	Not done
NSW should abolish the Electricity Tariff Equalisation Tariff (ETEF) and Qld should abolish the Benchmark Pricing Agreement (BPA) (3.5, 5.1).	Not done

» NSW has maintained the status quo since market start.

» WA is currently disaggregating components of the electricity industry across the South-West Interconnected System (SWIS) and is considering the establishment of a wholesale spot market.

» NSW has agreed to a staged phase out of ETEF. The phase out will be gradual between September 2008 and June 2010.

» QLD has abolished the BPA and a new arrangement (ie LEP) has been introduced in its place. QLD considers the LEP will become quite marginal in the future - as with the introduction of FRC on 1 July 2007, the LEP will apply to less customers. CSO arrangements are under review - the Qld Government will be publicly consulting on future CSO options for a post-FRC environment.

ACCC should include energy specific criteria in the Merger Guidelines (3.6).	Not done

» The Trade Practices Act (TPA) was reviewed in January 2003. The review committee concluded that industry-specific criteria should not be introduced to the TPA. ACCC has advised that amending the Merger Guidelines is unlikely to be effective as they do not have any legal force in determining breaches of the TPA.

» COAG has mandated the separation of ownership of generation and transmission assets in the NEM. The MCE is developing specific provisions to be set out in the National Electricity Law and enforced by the AER in consultation with the ACCC. Implementation of this decision is expected to occur in 2008.

Electricity transmission (Chapter 4)

NEMMCO be given responsibility for transmission planning, including:	Part done
– planning for the inter-regional and intra-regional transmission network (4.1a);	
– provision of independent and accurate information to inform the augmentation process and highlight potential augmentation opportunities (4.1b); and	
– establishment of competitive tendering for regulated transmission augmentation to relieve network constraints identified through the transmission planning process (4.1c).	Not done

» The first Annual National Transmission Statement (ANTS) was released in July 2004. The Statement is developed and published by NEMMCO and includes forecasts of future constraints and information on the nature, cost, scope, impacts and potential timing of augmentation proposals.

» Victoria conducts competitive tendering for transmission augmentations through its State planning body VENCorp.

NEMMCO to auction firm financial transmission rights (FTRs) to provide for efficient inter-regional trade and strengthen competition (4.2, 4.3).	Not done

» Improved financial trading arrangements, including the use of financial transmission rights, were discussed in the context of the MCE's regional structure review. No commitment has been made, at this stage, to the introduction of FTRs in the NEM. Under the 2005 MCE Transmission Package, the MCE has directed the AEMC to undertake a review of congestion management in the NEM, including identification and development of improved arrangements for managing financial and physical trading risks associated with material congestion. The AEMC will deliver a final report in early 2007.

Use the price of FTRs to provide clear signals for new investment in transmission (4.4). Use a 'commercial' regulated benefits test for intra-regional transmission augmentation (4.5).	Not done

» See comment at previous item. It is proposed that a congestion management regime will provide signals for investment that addresses transmission network congestion.

» The ACCC has amended the regulatory test to include the competition benefits. However, the approach taken (i.e. inclusion of competition benefits in an economic cost/benefit assessment) has further limited the ability of market based incentives to drive operational and investment efficiencies in the regulated network sector. The MCE has directed the AEMC to develop new regulatory test principles that support consideration of non-network alternatives to supply need. This will, in future, require linkages with transmission planning processes to encourage commercial involvement.

Develop incentives and penalties for Transmission Network Service Providers (TNSPs) to encourage more responsive network performance outcomes from TNSPs particularly during peak periods and extreme events (4.7, 4.8).	Part done

» The AEMC's draft transmission rules include a direction for the AER to develop incentives for transmission availability. This is to include incentives in relation to network availability that impacts on regional spot price outcomes.

Allow the number of regions to be set by the needs of the NEM, an increased number of regions and full nodal pricing to improve locational pricing, inter-regional trade and competition (4.9).	Part done

» The MCE has formed the view that the regional structure for the NEM should be stable, based on the current boundaries and with robust economic criteria to support incremental change as required. At the direction of the MCE, the AEMC is currently developing new rules for regional boundary change in the NEM. The proposed rules will allow regional boundary change to occur, based on long lead times and in relation to enduring historical network congestion.

» The MCE accepted the recommendation in the MCE Regional Structures review that no material efficiency benefits would be gained from a nodal pricing approach at this stage of market development.

Electricity financial market development (Chapter 5)

The National Electricity Code should reflect the principle that the impact of any changes to the Code must assess and take into account the likely impact on financial market activity (5.2). Future reviews of VoLL should take full account of the impact on contract premiums contract availability and access to prudential cover (5.3).	Not done

» Rule changes are assessed against the long term interests of consumers (the NEM market objective) under the National Electricity Law. Impacts on financial market activity that could have a material impact on consumer outcomes may be considered under this objective.

» In accordance with clauses 3.9.4(c) of the National Electricity Rules, the Reliability Panel is required to review the levels of the Value of Lost Load (VoLL) by 30 April each year. The Panel published its VoLL 2006 final determination on 28 April 2006. However, The Reliability Panel's annual reviews do not adequately consider the effects of financial markets when reviewing VoLL.

» The AEMC has initiated a Comprehensive Reliability Review that will include consideration of VoLL settings. Review will report in March 2007.

NEMMCO should review the need to take an active role to facilitate the introduction of a voluntary clearing service for bilateral contracts (5.4).	Part done

» NEMMCO is reviewing options for the introduction of a voluntary clearing service for bilateral contracts.

Demand side participation and full retail contestability in electricity (Chapter 6)

The NEM mechanism should be amended to include a demand reduction bidding option (6.1).	Rejected

» MCE considered and rejected the option of demand reduction bidding ('pay-as-bid') in its 2004 User Participation Policy Statement.

» The MCE has now established a Demand Side Response Working Group to develop a comprehensive and enhanced demand side response work program.

Installation of interval meters should be mandated for all energy consumers with the installation program to be achieved over the next 2 to 10 years (6.2, 8.4).	Part done

» In February 2006, COAG agreed to the progressive rollout of electricity smart meters from 2007.

» Current initiatives include the decision by Victoria for interval meters to be rolled out for all customers from 2008. Interval meters are voluntary for small users in NSW and Qld. Interval meters will be installed on a new and replacement basis in the ACT.

Full retail contestability should be introduced in all jurisdictions including the removal of price capping arrangements and other barriers to entry for retailers (6.3).	Part done

» Full retail contestability has been introduced in Vic, SA, NSW, ACT, and will be introduced in QLD from 1 July 2007.

» A National Distribution (non-economic) and Retail (non-price) framework is being developed by the MCE, with recommendations and national legislation expected to be finalised in 2007 to enable the new national framework to commence operations from 1 January 2008.

» The MCE User Participation Policy Statement released in August 2004 covered consumer advocacy; market mechanisms to promote demand side response in the NEM; the role of interval metering technology; and demonstration, information and capacity building. The MCE is continuing this work.

» The MCE has agreed to a process for implementing the removal of retail price caps where there is effective competition in a market. Effective competition assessments are expected to commence from 1 July 2007.

Increasing the wider penetration of gas (Chapter 7)

The Gas Code and access arrangements should be improved to create greater certainty for investors and greater competition in regulated pipelines (7.1, 7.2, 7.3, 7.4, 7.5).	Part done

» The MCE response to the Productivity Commission Review of gas access arrangements was released in May 2006.

» The MCE has agreed to the establishment of a new lighter handed form of regulation for covered pipelines.

» The MCE has also agreed to implement two new incentives to encourage investment and provide regulatory certainty for pipeline projects. Each incentive will require an application, independent assessment and recommendation by the National Competition Council, and a Ministerial decision:

  – A binding no-coverage ruling, whereby proposed projects will be exempted from all regulation for their first 15 years of operation; and

  – A 15 year price regulation exemption for international transmission pipelines which bring foreign gas to Australia – a pipeline granted this exemption will still be required to fulfil a number of non-price related obligations.

» These "greenfields" exemptions have been implemented in the existing gas access regime through changes to the Gas Pipelines Access Law (Schedule 1 of the *Gas Pipelines Access (South Australia) Act 1997*) and the *Trade Practices Act 1974*. They will be carried over in the new gas access regime, to be embodied in the new National Gas Law (NGL) and National Gas Rules (NGR).

» An exposure draft of the new legislation (NGL and NGR) which will implement these new features was released in November 2006.

Encourage greater competition by separate marketing in upstream gas (7.6, 7.7, 7.8, 7.9).	Not done

» Policy responsibility for upstream gas issues lies with the Ministerial Council on Mineral and Petroleum Resources (MCMPR). The MCMPR has considered and responded directly to all relevant recommendations from the Parer Review.

  – The MCMPR agreed in principle to the ACCC conducting a case-by-case assessment of the feasibility of separate marketing.

  – The MCMPR did not support the recommendations for mandatory notification of all future joint marketing arrangements or amending the TPA to preclude jurisdictions from exempting the application of s45 to joint marketing of natural gas as the Commonwealth already has provision to override any State/Territory exemptions from the application of this section to joint marketing arrangements.

  – The MCMPR endorsed the recommendation that new contracts be subject to the national consistent regime as currently applied through the TPA s45 and s90.

Include criteria to promote competition in acreage management regimes (7.10).	Not done

» The MCMPR did not see a systemic problem in acreage management regimes, but a paper is being developed on the issue.

Review the industry's principles for access to upstream facilities (7.11).	Part done

» The MCMPR is conducting a review on the effectiveness of the gas industry's upstream facility access principles.

Options to reduce greenhouse gas emissions (Chapter 8)

Introduce a greenhouse gas emissions trading regime (8.1, 8.2).	Not done

» The Australian Government has decided not to introduce a national emissions-trading regime due to the economic costs and inability to make a significant difference to global emissions.

» On 10 Dec 2006, the Prime Minister announced a new task group to advise on the nature and design of a workable global emissions trading system.

» The States have previously favoured a national emissions trading scheme but recently appear to be backing away from this position. The State and Territory Governments have established a Taskforce to develop a multi-jurisdictional emissions trading scheme (ETS). The Taskforce released a background paper in September 2005 and held stakeholder consultations at the end of 2005 and beginning of 2006. Recent media reports indicate that the future of the proposal is in doubt due to concerns about the effect of electricity price rises on households and large energy users if an ETS is introduced.

Transmission planning and regulatory arrangements today

Prior to the initial wave of energy market reforms electricity was supplied by fully integrated monopolies. Decisions relating to investment in generation and transmission were conducted within the same body with decisions and responsibility generally stopping at State borders.

In practice this meant that risks associated with meeting demand were managed through investment in spare capacity in both the generation and transmission sectors. This over-supply of capacity was seen as the primary inefficiency in the pre-reform electricity sector.

Competition reforms disaggregated the previously vertically integrated entities. Transmission planning investment and operational decisions continued to be made on a State-by-State basis and were primarily driven by jurisdictionally determined customer reliability obligations. In contrast investment and operational decisions in the competitive sectors are primarily driven by commercial drivers (risk minimisation and revenue maximisation) within the context of the market Rules.

As part of these competition reforms the transmission network was subject to independent economic regulation (as a natural monopoly) and ring-fenced from the competitive generation and retail sectors. Policy makers adopted a transmission framework for the NEM which includes:

- an open access regime for transmission. This means that all parties seeking access to the transmission system can do so on fair terms and conditions providing that they meet the minimum connection criteria set out in the National Electricity Rules;
- a common carriage regime for transmission. This means that full physical capacity of the transmission system is available to the market and dispatch of its use is on the basis of bids and offers for supply. No party holds a pre-emptory right to its capacity;
- an economic regulatory framework to determine allowable revenue (based on asset value) and therefore the price consumers face for transmission; and
- a transmission use of service (TUOS) pricing framework that charges customers only for the use of the shared transmission network;

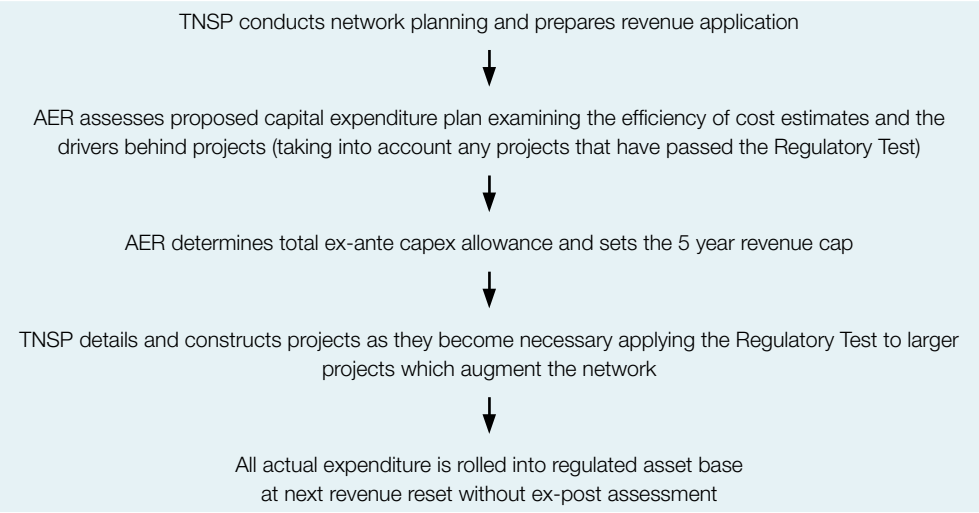
The long term allocative efficiency advantages of co-ordinating transmission and generation investment previously available within the vertically integrated firms now relies on the extent to which decisions in the regulated and competitive sectors can be co-ordinated through their respective planning investment and operational frameworks and the drivers these frameworks impose.

Current economic regulation framework

The AER regulates the revenue of all TNSPs under the National Electricity Rules and its Statement of Regulatory Principles. The current regulatory regime is based on the "regulatory bargain" concept in which standards of supply are set and revenue is regulated to allow the regulated entity to meet that given service standard. Incentives on operational and capital expenditure apply to encourage the entity to meet the service standard as efficiently as possible.

The process requires the AER to estimate the revenue needed to cover operational and capital expenditure over a 5 year period provide a risk adjusted rate of return on the Regulatory Asset Base and to allow for depreciation. Revenue determinations are carried out sequentially on each TNSP every five years. It should be noted that the AEMC issued its final determination in November 2006 following a statutory review of the economic regulatory framework. This is discussed further below.

3 Economic regulation of capital expenditure



Adapted from the ACCC/AER submission to ERIG August 2006

The vast majority of the required capital expenditure allowance is driven by state based reliability requirements on TNSPs. Because the revenue cap determination factors in the forecast capital works the economic regulatory process must work in parallel with investment planning undertaken by the TNSP for future network augmentation. Figure 1 sets out the relationship between economic regulation and transmission investment.

Incentive properties of current regime

The current regulatory approach provides an allowance for operational and capital expenditure on an ex-ante basis. The ex-ante approach for capital expenditure provides TNSPs with certainty that their actual expenditure over the period will be rolled into the Regulatory Asset Base with no threat of ex-post optimisation.

The incentive properties of the regime are based on the transmission provider retaining

during the regulatory period the difference between its actual spend and the forecast costs used to set the revenue determination. Revenue is fixed for five years at a time allowing firms to profit by any reduction in operating expenditure that occurs during the regulatory period. At the end of the regulatory period the new opex and capex forecasts are set for the subsequent regulatory period taking into account historic expenditure future demand forecasts and service standards requirements.

AEMC review of economic regulatory framework

The economic regulatory framework for transmission is currently the subject of a statutory review by the AEMC.

The AEMC final Chapter 6 determination contains a complete process and methodology for making a revenue determination. Under this regime the AER must accept a TNSP's estimate of its future revenue requirements if the TNSP meets stipulated obligations and requirements in its submission and if the AER is satisfied that the amount reasonably reflects efficient and prudent costs. The revenue requirement over the regulatory control period includes operating costs and the impact of capital spending during the period. The final rule includes the following key elements:

» the methodology and a number of the parameters used in the process for calculating the cost of capital will be included in the NER. These parameters are based on those in the Statement of Regulatory Principles (SRP) and will be subject to a limited review by the AER every five years;

» a requirement on network owners to provide a revenue proposal in accordance with the AER's published guidelines;

» directed guidance to the AER when exercising discretion including relevant consultation procedures including requirements on the AER to publish their reasoning for doing so;

» the calculation of the RAB on a 'locked-in' value of the assets;

» an efficiency benefit scheme will apply to operating expenditure; and

» a service standard incentive scheme to be developed by the AER with a maximum penalty/reward of 5% of the annual maximum allowable revenue based on maximising the availability of the network at times when it is valued most by the competitive market.

Current service standard arrangements

In conjunction with the Statement of Regulatory Principles (SRP) the AER publishes Service Standard Guidelines which outline the regulatory framework through which service standard measures are applied to transmission providers. The main purpose of the Guidelines is to provide a performance incentive scheme that ensures that capital expenditure (capex) and operational expenditure (opex) incentives do not erode service quality. The scheme is designed to drive the transmission provider's operating decisions as opposed to its capital decisions.

The objectives of the scheme are to ensure that transmission providers:

» are rewarded when performance standards increase and penalised when performance standards decline thus providing incentives for continued performance improvement; and

» consider how their operations are valued by the NEM.

Whilst transmission providers face statutory reliability obligations they can also be rewarded +/-1 percent of their regulated revenue for meeting performance targets. The three core performance measures that the AER incorporates when determining a transmission provider's revenue cap are:

» transmission circuit availability;

» average outage duration; and

» frequency of 'off-supply' events.

The AER has been considering additional performance incentives and in particular measures based on the market impacts of a TNSP's performance. Under the AEMC draft Rule the maximum penalty/reward is proposed to increase to +/- 5 percent.

Transmission pricing to consumers

The current transmission usage tariffs are set by each TNSP utilising the methodology as set out in the Rules. The AER set a revenue cap for each TNSP for each year of their regulatory control period. The cap for a particular year is calculated including:

» any escalation provision for changes to CPI;

» the rewards or sanctions for performance against service standards;

» any carryover excess or shortfall from previous years;

» any revenue from the auctioning of SRAs; and

» any other revenue variations.

The *aggregate annual revenue requirement* calculated for a TNSP must be divided between each of the following classes of *transmission service*:

» *entry services* or those services provided to serve a *Generator* or group of *Generators* at a single *connection point*;

» *exit services* or those services provided to serve a *Transmission Customer* or group of *Transmission Customers* at a single *connection point*;

» *common services* which are services that maintain *power system security* and benefit all *Transmission Customers* and which cannot reasonably be allocated on a location basis; and

» *transmission use of system service*.

The revenue to be recovered from each class of services is calculated pro-rata to the value of the assets that provide these services relative to the total regulated asset base. The majority of the assets are involved in providing the shared transmission network and hence the majority regulated revenue is recovered through transmission use of system services. Half of this revenue is recovered through locational Cost Reflective Network Pricing (CRNP) and the remainder as a general usage charge.

Entry and exit charges are recovered from the relevant generators or customers to whom they relate. All other transmission charges are recovered from customers. A small number of large customers are directly connected to the transmission network and would be billed on the basis of these charges. The vast majority of customers are connected to the distribution system and hence the distributor is the "customer" in relation to their transmission charges.

The Rules provide that common service charges and general usage charges are recovered either through a capacity related price expressed as a dollars per kilowatt per month ($/kW/month) charge or an energy component expressed as a cents per kilowatt hour charge (c/kWh) at the choice of the customer. This is to strike a balance between relatively high energy users who would face higher costs with a purely energy based charge compared with relatively high demand users who nevertheless place demands on the network capacity.

The usage component of the TUOS revenue is allocated to each connection point using the 'cost reflective network pricing' (CRNP) method defined in the NER. This appears to be a complex cost allocation method but is based on well-established network analysis methods. The end result is that the required revenue is allocated to connection points in proportion to the amount of network assets used to transfer power from the power stations to each connection point. The Rules allow flexibility in how the revenue to be recovered from each connection point is turned into tariffs. The following notes highlight these and any other differences taken in each jurisdiction to the general approach in the rules.

Queensland

The usage component of the TUOS revenue is allocated to each connection point using the 'cost reflective network pricing' (CRNP) method defined in the NER. The revenue allocated to each point in Queensland is then split into a capacity component ($/kW/month) and an energy component (c/kWh) using the forecast demand and energy for that connection point.

South Australia

South Australia's transmission pricing arrangement follows the general principles set out above except that the TUOS usage charge is calculated using a modified CRNP process approved by the ACCC which aims to reflect the utilisation of assets in the locational pricing approach. This is arguably more reflective of the long run marginal cost of supplying transmission service to a particular location. The TUOS usage charge is recovered based on a capacity price only expressed as a dollars per megawatt per day ($/MW/day) charge.

New South Wales

New South Wales (NSW) recovers its TUOS usage component through a tariff which includes a fixed price ($/day) a price for energy consumption in peak (c/kWh) shoulder (c/kWh) and off-peak (c/kWh) periods and a demand charge ($/kW/month). These charges vary across the different connection points but the fixed charge only applies to a selected few connection points where special circumstances apply. The peak and shoulder charge are currently set at the same rate.

Victoria

Victoria follows the national pricing arrangements set out above and recovers the TUOS usage charge as a capacity charge calculated in dollars per megawatt of summer demand per annum ($/MW pa). For these purposes the summer demand is calculated as the average of the 10 peak demands on weekdays during summer between 7 am and 11 pm.

Summary

An example of typical prices at a range of connection points in each jurisdiction that arise from this process are set out in table 7:

7 TUOS changes in selected regions

Location	TUOS Usage Prices			TUOS General Prices		Common Service Prices	
	Capacity		Energy	Capacity	Energy	Capacity	Energy
Brisbane CBD	0.6171 ($/kW/mth)		0.1639 (c/ kWh)	1.5928 ($/kW/mth)	0.4004 (c/ kWh)	0.9504 ($/kW/mth)	0.2387 (c/ kWh)
Adelaide East	36.288 ($/MW/day)		N/A	51.68 ($/MW/day)	5.136 ($/MWh)	32.671 ($/MW/day)	3.247 ($/MWh)
	Fixed	**Demand**	**Peak/ Shoulder**				
Sydney East	28 403.31 ($/day)	0.5822 ($/kW/mth)	0.2465 (c/kWh)	0.1431 (c/kWh)	0.5265 ($/kW/mth)	0.8477 ($/kW/mth)	0.2304 (c/kWh)
Melb West	9 905 ($/MW pa)		N/A	8 209 ($/MW pa)	2.0 ($/MWh)	17 408 ($/MW pa)	4.25 ($/MWh)

Transmission charges in distribution charges

Distribution pricing to date has been under the regulation of local regulators in each jurisdiction. The provisions regarding revenue and pricing set out in the national Rules are not generally applied as these provide for revenue regulation similar to that applying to transmission. Distribution is however generally price regulated. The Rules do require specific pass through of transmission charges to individual customers. They do however provide that a customer has the right to request separate disclosure of transmission and distribution charges where that customer has:

» a *load* of greater than 10MW or 40GWh per annum; or

» *metering* equipment which is capable of capturing relevant *transmission* and *distribution system* usage data

A charge may be levied by the distributor to provide this information making this information only worthwhile to very large customers who may be in a position to bypass the distribution system and connect direct to the transmission system.

The Rules also require distributors to publish information annually disclosing the transmission use of system and distribution use of system charges for each class of Distribution Customers. However these costs are generally averaged across whole customer classes and in some states averaged between distributors.

The regulatory test

The Regulatory Test consists of two limbs namely the reliability limb and the market benefits limb. The Regulatory Test can be seen as both a pure economic cost-benefit test and a pseudo ranking and consultative tool for reliability driven augmentations.

The reliability limb is used by TNSPs for considering augmentations considered necessary to meet their obligations to maintain standards of customer reliability. An augmentation satisfies this limb if it represents the least cost option of meeting that standard when compared to a range of credible alternatives.

The market benefits limb is applied to other proposed network augmentations. A new network augmentation satisfies the market benefits limb of the Regulatory Test if it maximises the net present value of the market benefits having regard to alternative options timing and market development.

The net market benefits assessed refers to the total increase in surplus (both consumer and producer) and does not include the transfer of surplus between consumers and producers.

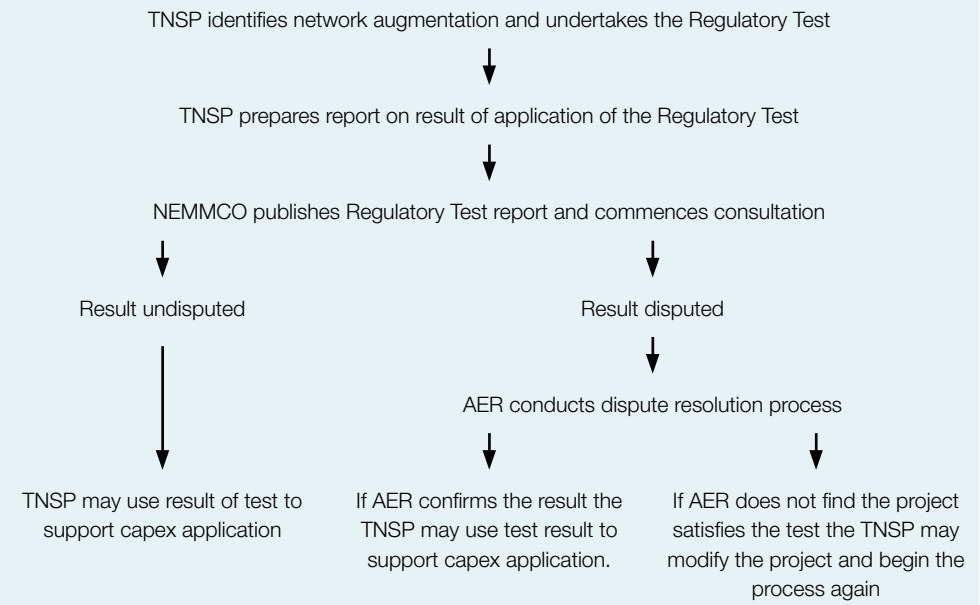
Proposals for a large network augmentation with capital costs greater than $10 million must be taken through full consultation and assessment as prescribed under the Rules and must satisfy one of the two limbs of the Regulatory Test before being constructed. Smaller augmentation projects must also pass the test but do generally require the full consultation process. Currently over ninety percent of network augmentations undertaken by TNSPs are conducted using the reliability limb of the Regulatory Test.

It is worth noting that a significant proportion of capital investment by TNSPs is refurbishment and replacement expenditure. These projects do not have to meet the Regulatory Test.

The governance surrounding the application of the Regulatory Test is inconsistent from State to State. The Regulatory Test is applied by ‘the proponent’ of a network investment. In QLD NSW Tasmania and SA the Regulatory Test is applied by the TNSP whereas in Victoria the Regulatory Test is applied by the independent transmission planner VENCorp. In South Australia the ESIPC has a role to review applications of the Regulatory Test to projects proposed by ElectraNetSA.

Regardless of who applies the test the broad process for Regulatory Test assessments for large network augmentations is illustrated below.

4 Regulatory test process



Source: ACCC/AER submission to ERIG August 2006

MCE rule change proposal

On 21 September 2006 the AEMC released a draft rule determination following a Ministerial Council of Energy (MCE) proposed change to the Rules governing the Regulatory Test.

The intent of the Rule change proposal is to improve the overall regulatory settings and establish a streamlined process that helps to maximise the net economic benefit to all those who produce consume and transport electricity in the market.

The only significant change to the Regulatory Test proposed by the AEMC in the draft rule determination relates to the assessment of alternative options under the current market benefits limb. A two stage process is proposed. Firstly a Network Service Provider (NSP) is required to publish a request for information on potential alternative options. The subsequent assessment stage will require the TNSP to assess the proposal against the likely alternative or alternatives rather than an assessment against all genuine and practicable alternatives.

Current transmission planning arrangements

The relationship between transmission planning and investment decision-making varies across jurisdictions:

» In NSW QLD and TAS transmission planning is the responsibility of the transmission asset owner;

» In SA the Electricity Supply Industry Planning Council (ESIPC) is responsible for planning information provision with the asset owner retaining responsibility for investment decision-making; and

» In Victoria VENCorp is responsible for transmission planning and the procurement of transmission network services. VENCorp conducts a tendering process to source some of these transmission services.

Intra-regional planning arrangements and obligations

The high level reliability standards included in schedule 5.1.2.2 of the Rules are very broad. Accordingly this requires the specificity to be added by the jurisdictional planning bodies which in most cases is the TNSP. As noted by Firecone this allows for very different standards of supply across jurisdictions.

Under the NER all TNSPs are required to develop an Annual Planning Report (APR). The APR assesses the adequacy of the transmission network to meet load growth forecasts for that jurisdiction. It reviews committed augmentations and network developments and is intended to be a key step in the provision of an economically optimum level of transmission system capacity.

In Victoria and SA an annual planning review is submitted to the responsible planning body VENCorp and ESIPC respectively who in turn produce the APR.

Different reliability standards apply in each jurisdiction both in form and in level. In NSW and Queensland the reliability standards are set in deterministic terms such as “N-1” style criteria. In Victoria VENCorp applies a probabilistic approach to network planning. Pursuant to the probabilistic approach an estimate of the Value of Customer Reliability (VCR) is used to calculate a cost benefit analysis on a proposed network augmentation or other solution.

South Australia applies a method similar to the probabilistic approach for each connection point and then translates the results of this analysis into deterministic planning standards for the individual connection points.

As such the jurisdictionally based TNSPs plan and develop their networks over time to maintain compliance with those obligations as demand rises.

Inter-regional planning arrangements

Inter-regional planning is co-ordinated between responsible jurisdictional planning bodies affected by any proposal for an inter-regional transmission augmentation. A jurisdictional planning body has the option to seek technical advice from the Inter-regional Planning Committee (IRPC).

Pursuant to the NER the IRPC is established by NEMMCO. The IRPC consists of:

» A NEMMCO representative as convenor;

» A representative from an entity in each jurisdiction of the NEM with responsibility for transmission planning and nominated by the relevant Minister in that jurisdiction; and

» Such other persons that NEMMCO considers have the appropriate expertise to be a member of the IRPC.

Members of the IRPC must not take part in any decision or determination of the IRPC where the entity they represent has a material financial interest in the matter under consideration. Costs are shared between NEMMCO as convenor and all entities represented by its members on a basis agreed by the IRPC. NEMMCO have never appointed other members to the IRPC.

Functions of the IRPC include to:

- provide such assistance as NEMMCO reasonably requests in connection with the preparation of the statement of opportunities;
- provide such assistance as NEMMCO reasonably requests in connection with the carrying out of the ANTS review;
- publish an objective set of criteria for assessing whether a proposed transmission network augmentation is reasonably likely to have a material inter-network impact;
- publish augmentation technical reports;
- publish an objective set of criteria for assessing whether a proposed new small transmission network asset or new large transmission network asset is a reliability augmentation;
- publish guidelines to assist Registered Participants to determine when an inter-network test may be required; and
- make recommendations to NEMMCO in relation to draft test programs.

The Annual National Transmission Statement

The Annual National Transmission Statement (ANTS) was first published in 2004. The ANTS replaced the Annual Interconnector Review that was originally published by the IRPC.

The ANTS is an attempt at providing a high-level integrated overview of the current state and potential future development of national transmission flow paths (NTFPs) over the next ten years.

The ANTS relies heavily on information from the TNSP's Annual Planning Reports and from NEMMCO's Statement of Opportunities. The ANTS includes a review of forecast constraints on NTFPs and options for relieving those forecast constraints.

On-going work related to transmission

AEMC review of congestion management arrangements

The issue of transmission congestion pricing and locational investment signals was recognised by the MCE as an important issue. The Ministerial Council on Energy (MCE) has directed the AEMC to review the effectiveness of the current congestion management regime in the NEM and to consider improvements in congestion management.

The review is to provide guidance in three key areas:

» identification and development of improved arrangements for managing financial and physical trading risks associated with material network congestion with the objective of maximising the net economic benefit to all who produce consume and transport electricity in the market;

» take account of and articulate the relationship between a constraint management regime constraint formulation regional boundary review criteria and review triggers the ANTS flow-paths the last resort planning power the Regulatory Test and TNSP incentive arrangements; and

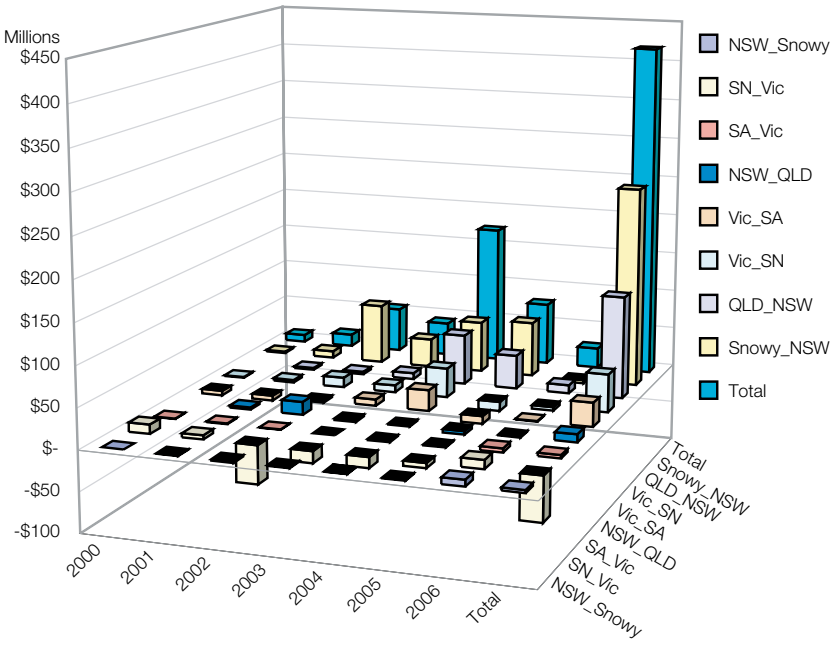
» how the constraint management regime should apply as a mechanism for managing material and enduring constraint issues until addressed through investment or regional boundary change.

SRA risk premiums and sources of volume risk across inter-connectors

SRA risk premiums

For each inter-connector and across time, Figure 5 shows the difference between accumulated settlement residues and SRA proceeds since market start. This is known as the SRA risk premium. It represents the *ex-post* returns to holders of SRA units for bearing the volume risk associated with non-firm flows across inter-connectors.

5 Settlement residue risk premiums across inter-connectors, 2006[1]



1. 2006 total to September only.

The volume risk associated with non-firm inter-connector flows may be related to transmission factors, such as intra-regional congestion, which is transferred to flows across inter-connectors. Volume risk may also be related to generator bidding behaviour, or some other factors.

Figure 5 shows total SRA risk premiums across all inter-connectors since market start ($418 M). The Snowy-NSW inter-connector has the highest risk premium ($251M), followed by the QLD_NSW inter-connector ($128M), Vic_Snowy ($47M) and Vic_SA ($30M). The Snowy-Vic inter-connector has a significant negative risk premium (-$55M).

To determine the potential sources of these risk premiums requires analysis on related intra-regional congestion which impacts on flows across these inter-connectors. In addition, any related generator bidding behaviour which impacts on these inter-connector flows must also be analysed.

SRA risk premium across QLD_NSW

The firmness (or volume risk) of flows across the QLD_NSW inter-connector is impacted by the following set of 6 constraints[4]:

- *Q:N_NIL_A* manages the loss of transmission lines between Armidale and Dumaresq in northern New South Wales. The limit can also vary subject to the operation of the two Millmerran generation units, the two Wivenhoe generation units and demand in QLD. It bound for 49 hours in 2004-05 and limited flows to an average of 908 MW. The constraint was revised in November 2004, increasing the limit on flows to 1100 MW.
- *Q:N_NIL_OSC* maintains stability in Queensland for the loss of the QLD_NSW inter-connector. The limit is set at 950 MW or 1078 MW depending on the operation of the two Millmerran generation units. When both Millmerran units are operating the 1078 MW limit is imposed. The limit bound for 120 hours in 2004-05, at all times binding at 1078 MW.
- *Q>N-NIL_D*F avoids overloading the 132 KV network in northern New South Wales. This network is in parallel to the 300 KV network connected to QNI and DirectLink. It bound for 5 hours in 2004-05 and on one occasion limited flows by more than 400 MW.
- *Q:N_AR_VC_1* manages the stability of the network in Queensland. It bound for 4 hours in 2004-05 and limited flows by more than 200 MW.
- *Q>N_AR_TX* manages network outages in the Armidale area. It bound for 26 hours in 2004-05 and limited flows to 100 MW.
- *Q>N-81_1T* manages outages of a line between Liddell and Newcastle. It bound for 88 hours in 2004-05 and also affected by some intra-regional constraints within New South Wales.

There are also other intra-regional constraints which impact on QLD_NSW flows.[5]

Table 8 shows the impact of these constraints on QLD_NSW flows using 5-min data in 2004-05:

[4] Australian Energy Regulator, Indicators of the impact of transmission congestion report for 2004-05, 10 October 2006, page 36.

[5] ibid, page 37.

8 Constraint examples affecting QLD_NSW flows 2004-05

Constraint	Period	Frequency[1]	Average flow [2] MW	Standard deviation MW
Q:N_NIL_A	1/7/04 - 9/9/04	589	901	153
Q:N_NIL_OSC	26/11/04 - 30/6/05	1445	1074	41
Q>N-NIL_DF	7/7/04 - 1/12/04	62	932	113
Q:N_AR_VC_1	13/10/04 - 14/10/04	47	737	50
Q>N_AR_TX	5/11/04 - 3/6/05	312	556	328
Q>N-81_1T	13/4/05 - 8/6/05	1055	520	300

1. Number of times contrained per 5-MIN flow. **2**. Average 5-MIN flow on QLD-NSW when constrained

Each constraint in table 8 is a source of volume risk which impacts flows across QLD_NSW and contributes to the SRA risk premium for 2004-05 shown in table 2 below:

9 QLD_NSW SRA risk premiums 2004–05

Quarter	SRA Risk Premium ($)
Sep 2004	3 445 335
Dec 2004	48 376 618
Mar 2005	-1 203 629
June 2005	2 006 429

This analysis suggests a significant proportion of the volume risk across QLD_NSW is related to transmission factors in northern New South Wales.

SRA risk premium across Snowy_NSW

The firmness of flows across the Snowy_NSW inter-connector is impacted by the following set of constraints :

» *H>N-NIL_H_15M, H>N-NIL_C_15M* or *H>N-64_H_15M* manage the overload of parallel lines in southern New South Wales which make up part of the Snowy_NSW inter-connector. These bound for 4 hours in 2004-05, however flows were consistently around 3000 MW when these lines constrained.

» *HN_2900* or *HN_3000* set an upper limit across Snowy_NSW. They bound for 2 hours during 2004-05 and flows across Snowy_NSW were limited by 250 MW during these times.

Table 10 shows the impact of these constraints on Snowy-NSW flows using 5-minute data:

10 Constraints affecting Snowy_NSW flows 2004–05

Constraint	Period	Frequency[1]	Average flow [2] MW	Standard deviation MW
H>N-NIL_H_15M	1/12/04 - 14/01/05	6	3133	189
H>N-NIL_C_15M	13/10/2006 - 1/12/04	5	3171	115
H>N-64_H_15M	1/12/04 - 14/1/05	6	3133	189
HN_2900	13/10/2004	11	2902	43
HN_3000	13/10/2004	11	2995	41

1. Number of times contrained per 5-MIN flow. **2**. Average 5-MIN flow on QLD-NSW when constrained

The information and analysis presented here suggests that the impact of these constraints on the significant volume risk for Snowy_NSW presented in table 11 below is minimal.

11 Snowy_NSW SRA risk premiums 2004–2005

Quarter	SRA Risk Premium ($)
Sep 2004	- 5 428 534
Dec 2004	67 957 185
Mar 2005	27 351 570
June 2005	-982 389

Unlike QLD_NSW, where transmission factors mostly explain the volume risk of inter-connector flows, Snowy_NSW exhibits significant volume risk even though flows across the inter-connector are relatively firm. This suggests factors other than transmission which significantly contribute to this volume risk.

SRA risk premium across Vic_Snowy

The firmness of flows across the Snowy_NSW inter-connector is impacted by the following set of constraints[6]:

- *H>>H-64_B* manages flows from Victoria to Snowy. This is done to insure that the 66 line between Murray and Lower Tumut is not overloaded for the trip of the 65 line between Murray and Upper Tumut.
- *H>>H-64_2* is a similar constraint to the one above.
- *VH_0000*, *VH_0050*, *VH_0100*, *VH_0150*, *VH_0200*, *VH_250* and *VH_0650* are discretionary constraints that limit flows across VIC_Snowy. These were predominantly used to manage negative settlement residues. However, recent rule changes by the AEMC aimed at minimising the impact of interventions by NEMMCO will decrease the use of such constraints and also reduce the volume risk across the inter-connector created by such intervention. From now on, any negative settlements accrued across Vic_Snowy will be funded from settlement residues across Snowy_NSW.

[6] Australian Energy Regulator, Indicators of the impact of transmission congestion report for 2004-05, 10 October 2006, page 38.

» *VH>V3NIL* and *VH>V4NIL* manage Victorian exports on VIC_Snowy and Murraylink to avoid overloading the South Morang 500/330 KV transformer when the network is in a radial configuration.

» *V:H_NILC_R* limits Victorian exports to manage the transient instability pursuant to the loss of the Hazelwood to South Morang 500 KV line.

» *V:H_NILB_R* limits Victorian exports to maintain transient stability on a trip of the 500 KV line from Hazelwood to South Morang.

There are also some intra-regional constraints affecting flows.

12 Constraints affecting Vic_Snowy flows 2004-05

Constraint	Period	Frequency[1]	Average flow [2]	Standard deviation
			MW	MW
H>>H-64_B	4/9/05 – 7/3/06	1025	1105 / 206	106 / 220
VH>V3NIL	2/7/04 – 26/6/05	990	723 / 738	217 / 231
VH>V4NIL	26/8/04 – 19/12/04	123	760 / 776	244 / 250
V:H_NILC_R	2/7/04 – 24/6/05	5302	1100 / 617	222 / 272
V:H_NILB_R	2/7/04 – 24/6/05	1860	898 / 728	143 / 168

1. Number of times contrained per 5-MIN flow. **2**. Average 5-MIN flow on QLD-NSW when constrained

H>>H-64_B has a significant impact on flows across Vic_Snowy (average flows 206 MW and St. Dev. of flows 220 MW) as shown in table 12. There are also significant times when negative settlement residues accumulate.

The analysis indicates that Snowy_NSW and *H>>H-64_B* flows are relatively firm. However, flows across Vic_Snowy are non-firm when *H>>H-64_B* binds.

The formulation of *H>>H-64_B* shows the variables which constraint *H>>H-64_B*. This formulation is:

» -1 TUMUT3;

» 0.504 HUMENSW;

» 0.165 BLOWERNG;

» -0.976 UPPTUMUT;

» -0.199 V_SN;

» 0.16 V-S-MNSP1;

» 0.972 SNOWY1.

The negative co-efficients on TUMUT3 and UPPTUMUT imply that increased generation at these locations relieves *H>>H-64_B*. The same is evident for Vic_Snowy. The positive co-efficient on Snowy_NSW inter-connector, however, implies that increasing flow across the Snowy_NSW inter-connector constrains *H>>H-64_B*.

The size of the coefficients on TUMUT3 (-1) , UPPTUMUT (-0.976) and SNOWY1 (0.972) suggests that increasing flows across Snowy_NSW and increasing generation at Lower Tumut and Upper Tumut by 1 MW each would relieve *H>>H-64_B* by 1 MW.

Increasing generation at Upper and Lower Tumut (bidding at lower prices) will contribute to relieving the intra-regional constraint, *H>>H-64_B*, in the Snowy region. Decreasing generation at these locations (bidding at higher prices) will contribute to constraining *H>>H-64_B*.

When this constraint is relieved, lower priced generation from Murray and Victorian generation can flow into NSW.

Volume risk and generator bidding in the Snowy region

The preceding analysis suggests that flows across the Snowy_NSW inter-connector are relatively firm. However, the Snowy_NSW SRA risk premium has totalled $251 M since market start (60 % of total SRA premiums across the market). This has been impacted by the regional design of the Snowy Region and the perverse incentives that this design creates for Snowy Hydro.

The impact of the material intra-regional constraint *H>>H-64_B* on Snowy Hydro's bidding behaviour and volume risk across Snowy_NSW and Vic_Snowy can be analysed by considering a case study of the events of December 7 2005. There was considerable peak demand in NSW on this day of 12,500 MW.

For each trading period between 2 pm and 3.15 pm on December 7 2005, table 13 shows, from left to right:

- Flows across Snowy_NSW (MW).
- When Snowy_NSW is constrained (Bind).
- Price difference between Snowy and New South Wales ($/MWh).
- When *H>>H-64_B* is constrained (Bind).
- Flows across VIC_Snowy (MW).
- When VIC_Snowy is constrained (Bind).
- Price difference between Victoria and Snowy ($/MWh).

13 Market events in the Snowy region, December 7, 2005

Time	Snowy-NSW			H>>H-64_B	VIC-Snowy		
	flow		price difference		flow		price difference
	MW		$/MWh		MW		$/MWh
14:00	2916	Bind	7017	Bind	132	Bind	4
14:05	2852	Bind	887	Bind	87	Bind	6
14:10	2898	Bind	907	Bind	24	Bind	4
14:15	2926	Bind	5480	Bind	92	Bind	6
14:20	2887	Bind	7320	Bind	42	Bind	9
14:25	2810	Bind	8624	Bind	16	Bind	6
14:30	2849	Bind	8518	Bind	78	Bind	3
14:35	2909	Bind	7400	Bind	90	Bind	-37
14:40	2911		1205		75	Bind	6119
14:45	2950		1209		123	Bind	6154
14:50	2947	Bind	8667	Bind	108	Bind	-36
14:55	2830	Bind	8560	Bind	-1	Bind	-38
15:00	2837	Bind	7400	Bind	69	Bind	-38
15:05	2917		1399		124	Bind	7125
15:10	2935	Bind	8560	Bind	87	Bind	-100
15:15	2923	Bind	1560	Bind	141	Bind	7339

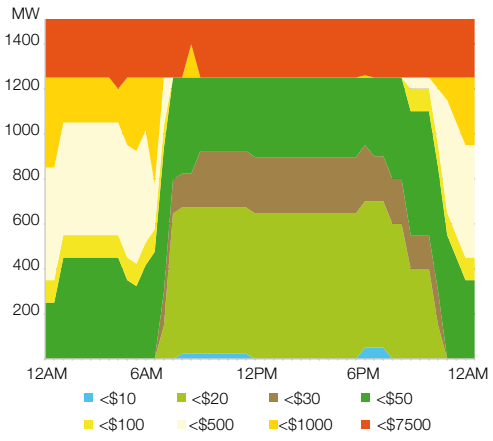
Table 13 shows that the Snowy_NSW inter-connector and *H>>H-64_B* constrain and unconstrain in unison between 2pm and 3.15pm. However, the VIC_Snowy inter-connector remains constrained throughout this period.

Flows across Snowy_NSW remain firm and close to its nominal capacity regardless of whether *H>>H-64_B* is constrained. VIC_Snowy flows, however, are non-firm, and well below the nominal capacity of VIC_Snowy.

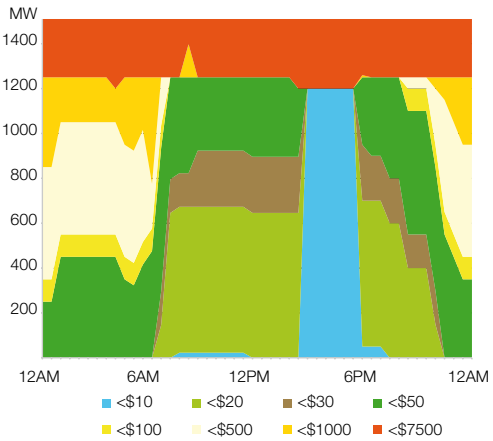
From 2.30 to 3pm, Murray rebid 1200 MW of capacity from higher prices to prices less than $10 MWh. This is shown in figures 6a and b respectively:

6 Murray generation rebidding between 2.30pm and 3pm

a – Bids as at 2:30pm

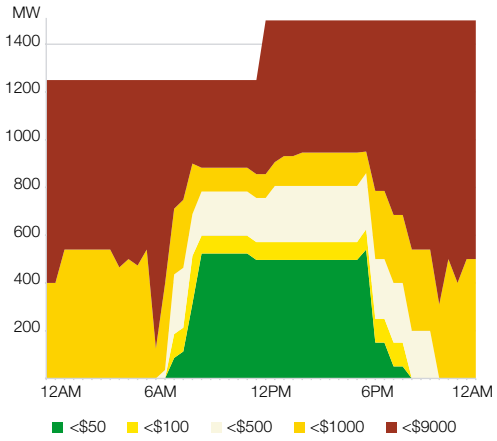


b – bids as at 3:00pm



Upper Tumut did not rebid any capacity; however, Lower Tumut steadily rebid capacity to prices under $100 MWh from prices above $9,000 MWh between 2.30pm and 4pm. This is shown in figure 7

7 Lower Tumut generation rebidding between 2.30pm and 4pm



As discussed, increasing generation at Upper Tumut or Lower Tumut has the effect of relieving *H>>H-64_B*, with greater dispatch of low priced Murray generation ($10 MW/h) into New South Wales ahead of Victorian generation; which is constrained due to the use of discretionary constraints on Vic_Snowy by NEMMCO aimed at reducing the accumulation of negative settlement residues. Regardless of Murray's bid it receives the Snowy location price for this capacity.

The regional design of the Snowy creates perverse incentives for Snowy Hydro to constrain and unconstrain *H>>H-64_B* with its bidding at Upper and Lower Tumut. Furthermore, by bidding at low prices for Murray generation, Snowy Hydro draws a response from NEMMCO who constrains flows across Vic_Snowy at certain limits to stop the accumulation of negative settlement residues. This occurs to the detriment of cheaper Victorian generation.

The new rules will transfer settlement residues from Snowy_NSW to Vic_Snowy at times when negative settlement residues occur.

These developments may reduce the SRA risk premium across Vic_Snowy because they will lower the risk of NEMMCO intervention. However, the effect of this will be the potential increase of the SRA risk premium across Snowy_NSW to compensate for the accumulated negative settlement residues. Should this occur, there is no actual benefit from the rule change, as generators trading through the Snowy region would still require SRAs across both inter-connectors.

Potential solutions to this problem should ensure that regional boundaries correctly reflect the network constraints; in this case *H>>H-64_B*. Furthermore, the potential for generation to impact network constraints should be addressed and solutions to contracting generation out of such situations be developed.

SRA risk premium across VIC_SA

The firmness (or volume risk) of flows across the VIC_SA inter-connector is impacted by the following set of constraints[7]:

- *VS_460* limits flows across the Heywood inter-connector to 460 MW. It bound for 975 hours in 2004-05. However when both Northern Power Station units are in operation in South Australia the inter-connector is limited to 160 MW due to a reclassification of constraints including *V:S_NPS_SINGL_CONT_2* which bound for 878 hours in 2004-05 and limited flows on VIC_SA.
- *V:H_NILC_R* limits Victorian exports to maintain the stability of the network when there is a risk that the Hazelwood to South Morang 500KV system can trip. It bound for 442 hours in 2004-05.
- *VS_150* manages network outages on the Heywood to South East Line and equipment outages around Heywood.
- *VS_250* manages the risk of the impact of a lightening strike on Heywood by limiting flows across the inter-connector to 250 MW when there is lightening within 80 km of the inter-connector. This constraint bound for 12 hours in 2004-05.
- *VS_380* limits flows across the Heywood inter-connector to 380 MW. It bound for 1 hour in 2004-05.
- *V>S_NIL* limits flows from Victoria to South Australia to manage thermal limits on the Heywood Inter-connector. It bound for 26 hours in 2004-05.
- *VSS_400* limits flows across both Heywood and Murray inter-connectors
- *V^SML_X5T*R manages a number of outages on elements of the 132KV and 33KV network in south western New South Wales which impact the operation of Murraylink. Flows across the Murraylink inter-connector can be limited to between 0 MW and 138 MW when these outages are managed.
- *SVML_000* or *VSML_000* manage outages of Murraylink or between Murraylink and Redcliffs in Victoria. Flows across Murraylink can be limited to 0 MW in both directions. The Murraylink inter-connector was out of service for 36 days in 2004-05. 23 of these days experienced unplanned outages.

There are also several intra-regional constraints in South Australia and Victoria which impact on flows across the inter-connectors.[8]

Table 14 shows the impact of these constraints on Vic_SA inter-connector flows using data on 5-minute flows in 2004-06:

[7] Australian Energy Regulator, Indicators of the impact of transmission congestion report for 2004-05, 10 October 2006, page 45.

[8] Australian Energy Regulator, Indicators of the impact of transmission congestion report for 2004-05, 10 October 2006, page 46.

14 Constraints affecting Vic_SA flows 2004-05

Constraint	Period	Frequency[1]	Average flow [2]	Standard deviation
			MW	MW
VS_460	1/7/04-1/7/05	11700	455	10
V:S_NPS_SINGL_CONT_2	14/3/05-1/6/05	10530	157	41
VS_150	10/5/05-31/5/05	567	139	18
VS_250	9/1/05-28/6/05	140	239	35
VS_380	29/07/04	17	381	33
V>S_NIL	14/11/04-22/6/05	308	437	24
VSS_400	30/07/04-30/07/04	26	202	168
V^SML_X5TR	25/11/04-15/6/05	728	65	30
SVML_000/VSML_000	9/9/04-30/6/05	3624	2	2
VS_460	1/7/04-1/7/05	11700	455	10

Table 14 shows there are some significant transmission constraints affecting Vic_SA flows; including constraints which significantly impact on flows across Murraylink. It also shows significant generation impacts from the management of contingencies at the Northern Power Station which constrain flows across Vic_SA. Rather than constraining generation when there is a contingency at the Northern Power Station, V:S_NPS_SINGL_CONT_2 constrains flows across Vic_SA and contributes to non-firmness and a significant risk premium across Vic_SA. This is a relatively new constraint.