Australian Energy Market Commission

THE STATE OF THE AUSTRALIAN ELECTRICITY MARKET 2008

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Conference Paper

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The State of the Australian Energy Market 2008

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1. Introduction

The Australian competitive wholesale energy market is about to undergo the greatest test in its brief ten year history. A confluence of factors including increasing peak demand; reducing spare generation capacity; and the introduction of climate change policies designed to price greenhouse emissions, are leading to the need for new and potentially significant generation investment, supported by augmentations to the transmission network. Even in the absence of climate change policies, this would be a test for the market. However, climate change policies add a new dimension to the challenges the market faces in providing the new investment.

The Australian energy market in 2008 is therefore at the brink of a new phase. This phase builds upon earlier evolutions of the market, and is expected to result in an expansion of gas-fired and renewable generation to satisfy growing demand for electricity.

The Australian Energy Market Commission (the Commission) is responsible for assessing proposed changes to the market rules, market development and the provision of policy advice to government for both the electricity and gas markets. We are obliged to accept rule change proposals that are consistent with promoting economic efficiency in the provision of electricity and gas services.

In its short existence, the Commission has been considering many of the critical questions that the market is facing including (amongst others):

- the framework for the economic regulation of transmission network services;
- the approach to managing network congestion;
- the effectiveness of retail competition;
- the approach to reliability;[1]
- impediments to demand-side participation; and
- arrangements for national transmission planning.

The Commission is currently considering the implications of climate change policies for the rules.[2] These reviews have provided the Commission with a unique perspective on the energy market and its development.

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1 Through the Reliability Panel, established under the national electricity rules, with members including an AEMC Commissioner, representatives of industry and the independent market and system operator, NEMMCO.

This paper provides a brief assessment of the state of the Australian energy market in 2008 and provides insights on critical market development questions. These insights draw upon the Commission's experiences during the various reviews and rule change proposals that it has considered to date.

The remainder of this paper is structured as follows:

- section 2 briefly describes the current institutional and regulatory arrangements operating within the Australian energy market;
- section 3 focuses on the mechanisms within the market that provide incentives for new generation investment. This section describes the new generation investment challenge, and the key market parameters that influence generation investment decisions;
- section 4 focuses on the regulatory incentives for network investment and the challenges faced to construct efficient network extensions to provide transfer capability to the new generation investments;
- section 5 considers the retail sector and its relationship to generation investment; and
- section 6 concludes.

2. Current institutional and regulatory arrangements in the Australian energy market

This section provides a brief overview of the current institutional and regulatory arrangements operating within the Australian energy market.

2.1. Evolution of the market

Prior to the commencement of energy reforms in the early 1990's, the Australian electricity industry was made up of large, vertically integrated and government-owned authorities. These authorities provided a complete electricity service to end-use customers, including electricity generation, transmission, distribution and retail.

The gas industry was also mainly made up of government-owned authorities that provided transmission, distribution and retail gas services. However, there was greater private sector involvement with wholesale gas supply, exploration and some distribution and transmission networks being provided by the private sector.

The reform process was strongly grounded in the principles of promoting competition and efficiency. In 1995, National Competition Policy (NCP) was developed and adopted by the Commonwealth Government and all State Governments, and set out a program of reform to achieve its key principles.[3]

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2 For further information about this review visit the AEMC website, www.aemc.gov.au.

3 The development of NCP was overseen by the newly formed Council of Australian Governments (COAG), made up of the heads of each state and territory, and the commonwealth governments.

NCP was formulated following an independent inquiry into national competition, chaired by Professor Frederick Hilmer, which recommended:

- reform and nation-wide application of competition law
- the application of competitive neutrality principles so that government businesses do not enjoy a competitive advantage simply as a result of public sector ownership;
- the restructuring of public sector monopoly businesses; and
- the provision of third party access to nationally significant infrastructure.

While NCP extended beyond the electricity and gas industries, these industries were a particular focus because of the anticipated benefits associated with the creation of national gas and electricity markets.

In December 1998, the National Electricity Market (NEM) was formed, creating a single market for electricity supply across the east coast of Australia, including Queensland, New South Wales, Victoria, South Australia, and the Australian Capital Territory. Tasmania joined the NEM in 2005 prior to the completion of BassLink in 2006, which connected the Tasmanian network to mainland Australia.

For the gas industry, the immediate focus was on developing nationally consistent arrangements for third party access to pipelines.[4] The national gas code applied in all states and territories and set out principles for access to Australian natural gas transmission and distribution pipeline services.

For both the electricity and gas industries, independent economic regulators were established in each jurisdiction. These jurisdictional regulators were given responsibility for network regulation, in accordance with the national framework. A federal regulator (the Australian Competition and Consumer Commission (ACCC)) was given responsibility for electricity and gas transmission network regulation.

By the end of the 1990s the initial reforms of the gas and electricity markets were more or less complete, with the majority of electricity authorities having been vertically separated into generation, transmission, and combined distribution and retail businesses in each jurisdiction.

However, this new framework was not without problems. Concerns soon emerged about inconsistencies in the interpretation and application of the national electricity and gas code requirements by jurisdictional regulators. Specific areas of contention included:

- divergent approaches to driving efficiency through the use of incentive mechanisms;

COAG provided a mechanism for national frameworks to develop for matters that were otherwise primarily within the sole powers of the state.

4 The *National Third Party Access Code for Natural Gas Pipeline Systems* (the gas code).

- the assumptions used to determine the required rate of return on infrastructure investments;
- the methodology adopted to establish the value of the regulated asset base; and
- the weight placed on the various factors that regulators were required to take into consideration.

In response to these concerns an independent review of the strategic direction for energy market reform in Australia[5] was undertaken. This led to the establishment of the Ministerial Council on Energy[6] (MCE), to provide a forum for national leadership on energy policy issues. In 2003, the MCE agreed to a series of new reforms to the energy market[7], including the establishment of two new statutory commissions, namely:

- the Australian Energy Market Commission (the Commission); and
- the Australian Energy Regulator (AER).

The Commission is primarily a rule-making body and is responsible for setting the rules governing operation of the NEM and the national gas network, including consideration of any proposed rule changes submitted by market participants. In addition, it has responsibilities for market development and the provision of policy advice to government for the electricity and gas industries.

The concentration of rule making powers in a single, independent body is designed to enhance the confidence of market participants in the stability and integrity of the rules, and thereby foster a more secure investment climate. This is achieved in part through the development of a single National Electricity Objective (NEO) and National Gas Objective (NGO), which are the principal tests for changing the NERs or NGRs respectively.[8]

The AER was established as the national energy market regulator, subsuming a range of regulatory responsibilities previously held by the ACCC for gas and electricity transmission. The AER's primary role is to apply the rules developed by the Commission. Since commencement, the AER has taken major steps toward national regulatory consolidation by assuming responsibility for electricity and gas distribution regulation.[9]

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5 COAG, (2002), Towards a Truly National and Efficient Energy Market, Final Report of the Council of Australian Governments' Independent Review of Energy Market Directions, December.

6 The MCE includes Commonwealth, State and Territory energy ministers, in addition to ministers from New Zealand and Papua New Guinea as observers.

7 As part of this stage of reform the National Electricity Rules (NERs) were established in the National Electricity Laws to govern the operation of the NEM. Similarly, *National Gas Rules*[7] (NGRs) were developed.

8 Any proposed rule change submitted to the Commission must be considered to promote the achievement of the NEO or NGO as relevant, in order to be approved.

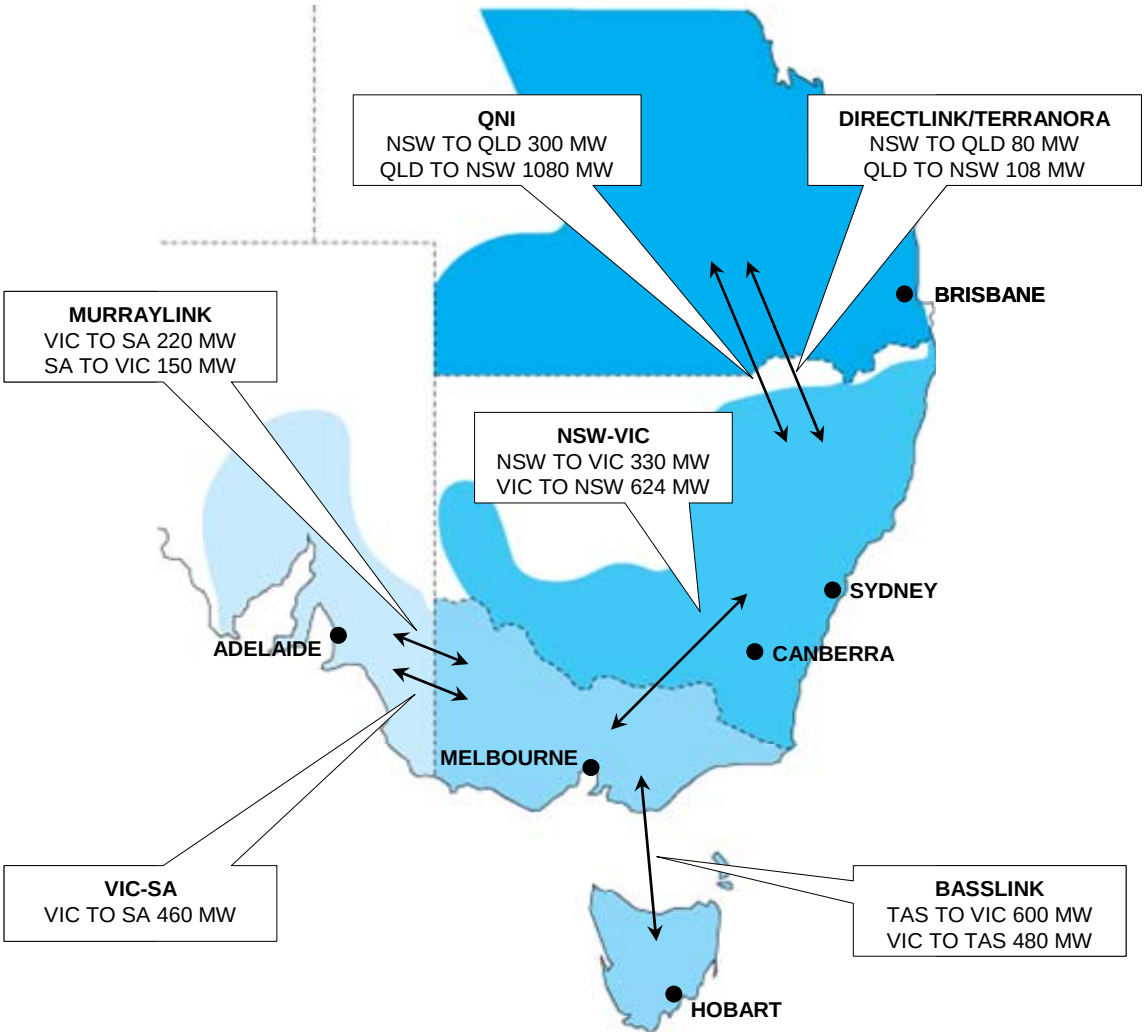
9 On 1 January 2008 and 1 July 2008, respectively.

2.2. The wholesale electricity market

2.2.1. Structure of the NEM

The NEM is the wholesale electricity market that links New South Wales, Victoria, Queensland, South Australia, the Australian Capital Territory and Tasmania. Both Western Australia and the Northern Territory do not participate because they are not physically connected to the NEM network.

Figure 2.1
The National Electricity Market



The principal parties that are registered to participate in the NEM include generators, transmission and distribution network service providers, retailers, large customers, special participants and traders.

In January 2008, the NEM had a total generation capacity of 45 GW. Of this capacity, 61 per cent was fuelled by coal, 17 per cent was fuelled by hydro, 16 per cent was

fuelled by natural gas and the remainder was fuelled by a combination of oil, wind and other fuels.[10]

Regarding ownership of the generation assets, those in New South Wales, Queensland and Tasmania are state owned utilities. In contrast, Victoria and South Australia have both privatised their generation assets.[11] The ownership structure of transmission and distribution assets is based on a similar structure with the exception of Tasmania, which has a state owned distribution system and a privately owned transmission system connected to Victoria.

2.2.2. Operation of the NEM

The NEM can be characterised as a gross pool, regionally settled, energy only market. Under this arrangement generators are required to sell their electricity into the pool and electricity is then dispatched to meet demand. The payment generators receive is based only on the quantity of electricity that is supplied and not for other services such as capacity or availability.

The corresponding wholesale prices that generators receive (and retailers and customers pay) are determined using the spot market. These prices can be highly volatile due to:

- electricity being non storable;
- the demand being very dependant on temperature;
- the supply and demand both being inelastic during periods of scarcity; and
- unplanned generator and transmission line outages.

The incidence of price volatility is essential to the long term viability of the NEM. In an energy only market, price volatility serves two purposes:

- to enable generators to recover fixed costs:
  - with no capacity payments in the NEM, there needs to be sufficient periods in the year when the spot price is high enough that settlement payments to generators are above their short run marginal costs and are able to contribute to their fixed costs; and
- to signal supply scarcity relative to demand:
  - high wholesale prices are the principal signal of electricity scarcity and accordingly provide incentives for new investment in generation, particularly peaking generation.

While price volatility has an essential role in the NEM, it also creates a significant risk for retailers and customers because they are required to purchase all their energy on the spot market. In periods of high and prolonged pool prices, participants will incur high wholesale energy costs, potentially creating a significant financial liability.

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10 Electricity Supply Association of Australia, (2008), Electricity Gas Australia 2008.

11 Electricity Supply Association of Australia, (2008), Electricity Gas Australia 2008.

Two principal methods used to manage price volatility risks. First, retailers and generators enter into forward contracts to supply electricity. The main types of contracts are swaps and caps, which have the effect of limiting exposure to high or volatile wholesale prices.

Second, the rules provide a number of risk mitigation provisions that can be used by NEMMCO – the independent system and market operator – to manage price volatility risk. These provisions can be used during periods of high and/or prolonged high prices, in order to sustain electricity trading and limit the financial risks to market participants. These provisions include:

- value of Lost Load (VoLL):
  - This is a price cap of $10,000 per MWh and represents the assessed value of the load that cannot be supplied in the event of a supply shortfall.
  - The VoLL is intentionally set at a high level to encourage participants to manage the risk of price volatility by entering into financial contracts or undertaking demand side response. The price of these contracts or demand side response is then intended to act as a signal for new investment.
  - In the last three years the VoLL has been reached in Victoria, South Australia and New South Wales.
- cumulative price threshold (CPT)[12]:
  - The CPT is the cap for cumulative prices in the NEM over a rolling seven day period.
  - It is currently set at $150,000 MWh and in the event that the cumulative price exceeds this amount (which is equivalent to an average spot price of $446.43/MWh over seven days) then an administered price cap of $300 MWh is used.
  - The CPT limits the exposure of market participants to high and protracted pool prices.
  - Since the NEM's commencement the CPT has only been breached once, in South Australia in March 2008, following a period of consistently high temperatures.
- reliability safety net (otherwise known as the reserve trader provisions):
  - NEMMCO has the power to intervene in the NEM to address any potential shortfalls of supply below the minimum reserve level.[13]

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12 A recommend increase in the values of VoLL and the CPT of 25% from the 1 July 2010 is being considered.

13 The current reserve requirements stipulate that no more than 0.002 per cent of energy demand in any region should be at risk of not being supplied over the long term.

- NEMMCO can intervene by either purchasing additional reserve generation capacity or demand side response, or by requiring generators to provide additional supply at the time of dispatch.

- Since its inception, the reliability safety net has been used twice. In both cases NEMMCO contracted to purchase reserve capacity to meet summer peak demand, although in each case it was not required to dispatch the reserve capacity.

The VoLL, CPT and reliability safety net described above are emergency provisions only and were not designed or intended for regular use. Instead to manage price volatility market participants can use a range of tools such as swaps, futures and options. The principal feature of these tools is that they are designed to allow the market participant to lock in the price of a given quantity of electricity at a future date.

2.2.3. Networks

The transmission and distribution network components of the electricity supply chain can be characterised as natural monopolies. To prevent the potential exercise of market power by the owners of these assets, electricity transmission and distribution services are subject to economic regulation.

The electricity transmission and distribution networks within the NEM are managed as a common carriage network. Under this approach a generator pays a connection charge, based on the direct costs incurred for connection, to gain access to the transmission and distribution networks and is then free to sell electricity via contract to any retailer in the wholesale market.

At the same time, the retailer pays a connection charge and a use of system charge for access to the transmission and distribution networks. The retailer may also purchase electricity via contract from any seller without needing to book or be allocated any transmission network capacity. The common carriage model therefore precludes the need to allocate network capacity to any generator or retailer.

NEMMCO[14] is responsible for system safety and ensuring that electricity demand and supply remain in balance, as the independent market and system operator. By dividing the NEM into regions, and therefore allowing spot prices to diverge between regions, transmission network delivery constraints between regions are effectively priced into the market, ie, if there are no delivery constraints then the spot price for electricity is the same across all regions (adjusted for electrical losses).

Network planning and investment is also facilitated by NEMMCO. Specifically, NEMMCO is responsible for identifying investment opportunities in transmission network augmentation through the preparation and publication of the Annual National Transmission Statement (ANTS). The ANTS identifies technically feasible

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[14] The new Australian Energy Market Operator (AEMO) will officially commence operations on 1 July 2009 and all functions carried out by NEMMCO will transition to the AEMO. The AEMO will also become responsible for a new, expanded transmission planning role that covers electricity *and* gas planning.

modifications that can be implemented to address both current and forecast system constraints on the transmission network.

The Commission has recently conducted a review to consider proposed national transmission planning functions, to be undertaken by the newly formed Australian Energy Market Operator (AEMO).[15] The AEMO will be required to publish annually a national transmission network development plan (NTNDP), to facilitate long-term management of the transmission network.

For an electricity transmission network service provider to be allowed to recover the cost of infrastructure investment through user charges (ie, to include this expenditure in the recoverable asset base) they must be able to demonstrate that the investment satisfies the Regulatory Test[16]. This test is designed to support an efficient level of investment in network infrastructure by distinguishing between those investments with localised benefits versus those that offer broader wider-economy benefits.

2.2.4. Retailing

Since the 1990s electricity supply across NEM jurisdictions has undergone significant reform in terms of restructuring, corporatisation and privatisation. Specifically, the vertical separation of the electricity supply chain led to the separation of retail functions from electricity generation, transmission and distribution. Progress towards achieving fully-competitive retail markets varies across jurisdictions. Full retail competition commenced being introduced in 2002.

The central function performed by an electricity retailer in any Australian jurisdiction is to act as an intermediary between the electricity generator and the end use customer. Retailers purchase wholesale electricity and then contract with domestic and small business customers to sell electricity at specified prices under either a standing offer or market contract.

The Commission is responsible for reviewing the effectiveness of retail competition in electricity and gas retail markets in each jurisdiction (except Western Australia[17]). Where competition is found to be effective, the Commission is to provide advice on ways to phase out retail price regulation. Where competition is found not to be effective, the Commission's advice must suggest ways to improve competition. So far the Commission has completed reviews of retail competition in Victoria and South Australia.

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15 AEMC, (2008), *National Transmission Planning Arrangements,* Final Report to the MCE, June.

16 National Electricity Rules (version 21), Section 5.6.; National Gas Rules 2008, July 2008, Section 79; and, AER, Final Decision, Regulatory Test version 3 & Application Guidelines, November 2007.

17 The Economic Regulation Authority of Western Australian (ERA) is responsible for undertaking a similar review in Western Australia.

In Victoria, the Commission found that both electricity and gas retail competition was effective and therefore recommended that the regulation of standing offer retail prices for residential customers cease from 1 January 2009. The Commission also found retail competition to be effective in South Australia, and has recommended the replacement of the existing framework for regulating retail energy prices with ongoing regulatory price monitoring regime.

2.3. The wholesale gas market

The Australian gas market is characterised by long-term, highly customised bilateral gas supply contracts entered into on an infrequent basis by producers and a limited number of end-users. Long term contracts are preferred by gas producers to underwrite the significant capital investment required at the commencement of a gas field's life.

However, this preference for entering into long term gas supply contracts is not solely driven by the needs of producers. Gas purchasers generally also require secure access to gas over the longer term. This is either because firm access to gas over a long period underpins a decision to adopt gas fuelled technologies, or because it is required to meet the projected future demand for their end product.

To secure the supply of gas, retailers are generally required to enter into a long term contract with a producer(s) that specifies the quantities it will purchase in each year of the contract life, and establishes the minimum quantities that must be taken or paid for in each year. The take or pay provisions operate as a minimum bill that must be met by a retailer even if actual demand is below the take or pay quantities. Viewed in this way the minimum bill operates as a fixed cost for retailers. In addition to paying the ex-plant price of gas, retailers incur negotiation and contracting costs at both the commencement of the contract and at each price reset.

While gas is mainly sold under long-term contracts with terms of three to twenty years, there are buyers that will use short term contracts to supplement their existing contracted supplies. For example, retailers in south eastern Australia will tend to supplement long term contractual supplies with additional gas during the winter months. The Victorian gas market is an exception to the gas market arrangements described above.

While long term gas contracts are used in Victoria, there is also a physical spot market. The physical spot market provides users with a mechanism to trade gas on a daily basis to manage supply imbalances. The spot market is settled as a net market, such that market participants pay for the excess of actual withdrawals over actual injections, or receive payment for the excess of actual injections over actual withdrawals with the price paid or received being determined within the market.

2.3.1. Reform and developments

In recent years the Australian gas market has experienced significant reserve growth through the development of coal seam methane reserves (CSM), and there are also reforms occurring to the market structure. These are described briefly below.

2.3.1.1. Market structure reform

Two reforms to the operation of the gas market are currently being implemented, namely:

- the introduction of a Gas Market Bulletin Board (BB); and
- the development of a gas short term trading market (STTM) in New South Wales and South Australia.

The Bulletin Board was launched in July 2008 and is a website/portal that provides information and data to promote trade in gas over the interconnected pipelines. The information provided covers all major gas production fields, demand centres and natural gas transmission pipeline systems in all states, with the exception of Western Australia and the Northern Territory.

Provision has been made for these states to be included in the future. The objective of the BB is to facilitate trade in gas and transmission pipeline capacity in eastern Australia through information sharing and by improving the transparency of market information.

The short term trading market is currently undergoing a detailed design phase and is expected to be implemented in New South Wales and South Australia by mid 2010. The short term trading market is expected to be expanded to other jurisdictions, excluding Victoria, in the future.

The short term trading market aims to facilitate daily gas trading by establishing a mandatory price based balancing mechanism for gas that is delivered and withdrawn from defined market hubs, ie, Sydney and Adelaide.

The short term trading market is not intended to replace the existing long term bilateral relationships that exist between producers, buyers and pipeline owners. Rather, the short term trading market will operate in conjunction with the bilateral contract market and will be used to manage short term supply and demand fluctuations. It will therefore replace existing balancing arrangements at those hubs.

2.3.1.2. Market developments

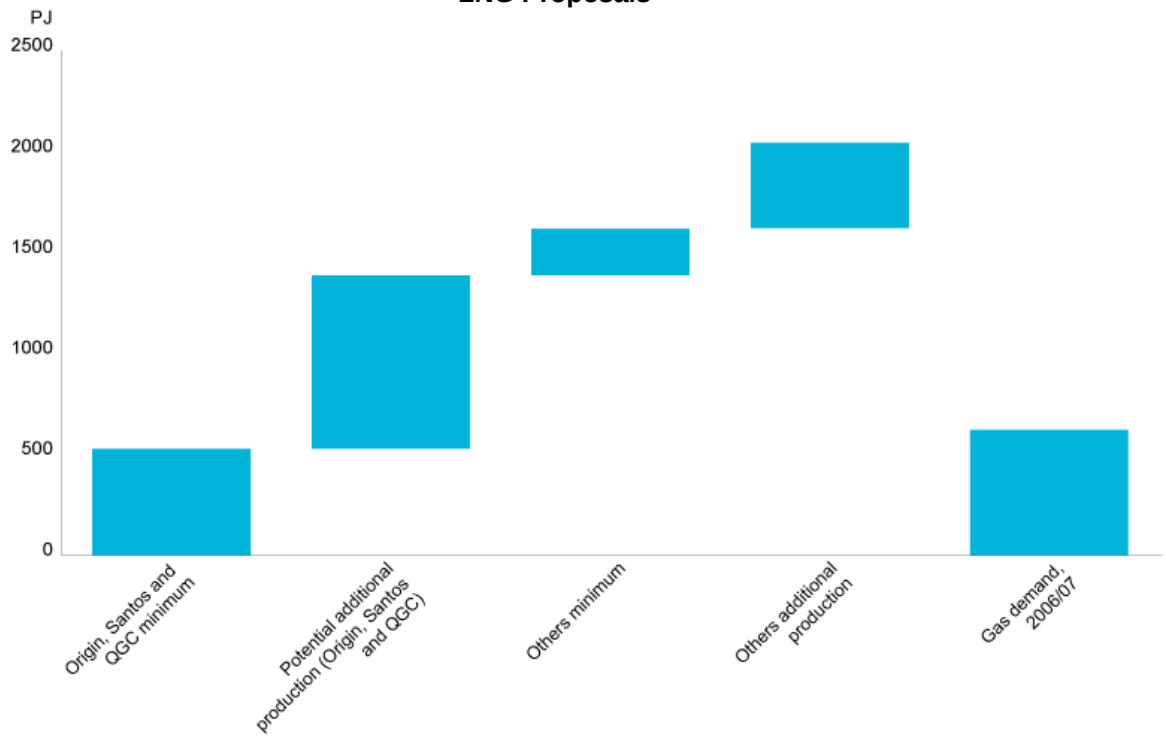
In recent years the coal seam methane (CSM) industry in Queensland has been transformed. Stimulated in part by the Queensland government's gas scheme, where 13 per cent of all Queensland electricity must be sourced from gas-fired generation, and increased confidence within the market. Over this period, CSM has been transformed from a speculative and unreliable source of gas, to a reliable and commercially viable source.

The large scale of CSM reserves in Queensland has prompted a number of significant participants in the gas market to consider developing LNG facilities in northern Queensland. Currently there are six separate proposals to develop LNG facilities, three of which have been proposed by significant players in the Australian market.

If all six proposals are developed at their minimum scale then over 750 PJ per annum of CSM would be effectively removed from being available for the domestic market from 2014. To put the scale of these proposals into context, total demand in eastern

Australia was approximately 620 PJ in 2006-07 while demand in Queensland was approximately 109 PJ in 2006-07.[18,19]

Figure 2.2
LNG Proposals[20]



2.3.2. Gas networks

Unlike the NEM, all jurisdictions in eastern Australia, with the exception of Victoria, operate gas transmission networks under a contract carriage model. This model requires a retailer to enter into a contract for transmission services, which specify the capacity reserved and the delivery locations.

Since transportation charges are mainly capacity based, the transportation cost incurred by a retailer operating in these jurisdictions is fixed. In addition to paying transportation charges, retailers also incur negotiation and contracting costs.

However, a retailer in Victoria is not required to enter into capacity based transportation contracts. Instead a retailer simply nominates transmission pipeline capacity requirements and VENCorp, the gas system operator, bases pipeline charges on throughput.

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18 ABARE Historical Statistics, Table F – Australian energy consumption, by industry and fuel type.

19 ABARE Historical Statistics, Table H – Australian production of primary fuels.

20 Arrow Energy, Energy World Corporation, LNG Impel, QGC, Santos and Origin.

3. Satisfying new generation investment needs

Australia has benefited from an extended period of surplus base load generation capacity that has resulted in new generation investment being constructed to service growing peak load requirements. However, the time for new base load generation investment is approaching as demand continues to grow.

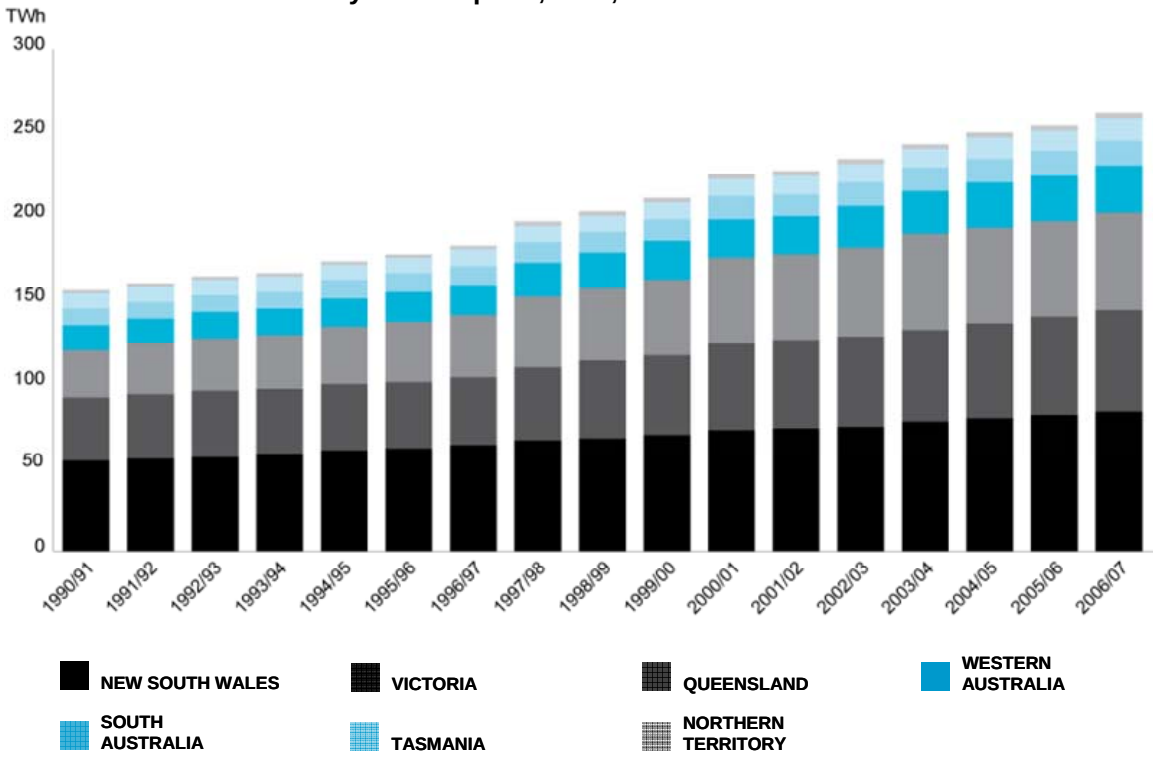
This section briefly sets out expectations about the future growth in electricity demand, and discusses the implications for new generation investment. The section concludes with a discussion of the factors that are likely to influence generation investment decisions.

3.1. The generation investment challenge

3.1.1. Electricity demand

In 2006-07 Australia generated around 262 TWh[21] of electricity, which represented an increase of 67 per cent since 1990-91 - Figure 3.1. Since the commencement of the NEM, the average annual rate of growth in electricity demand has varied across each region, with Queensland having the highest growth rate of 4.0 per cent, and New South Wales and South Australia the lowest, at 2.6 and 2.8 per cent respectively.

Figure 3.1
Electricity consumption, TWh, 1990-91 to 2006-07[22]



21 ABARE Historical Statistics, Table I - Australian consumption of electricity, by state.

22 ABARE Historical Statistics, Table I - Australian consumption of electricity, by state.

ABARE forecasts electricity consumption to increase by an average of 2 per cent each year until 2029-30, by which electricity generation is projected to reach 415 TWh.[23] Queensland will account for over 30 per cent of total Australian electricity generation by 2019-30, up from 22 per cent in 2006-07. Average annual growth in electricity consumption is projected to be strongest in Western Australia and Queensland over this period, with ABARE forecasting growth of 2.8 and 2.4 per cent per annum respectively.

3.1.2. Generation capacity

Total electricity generation capacity was approximately 51.6 GW in 2006-07, with over 55 per cent of total capacity accounted for by coal generators - Table 3.1. Renewable generators accounted for 9.4 GW of generation capacity, which represented approximately 18.2 per cent of total capacity.

Table 3.1
Generation capacity, MW, 2006/07[24]

	NSW / ACT	Qld	Vic	WA	SA	Snowy	Tas	NT	TOTAL
Coal	11,741	8,125	6,555	1,319	780	0	13	0	28,533
Natural gas	304	2,170	1,962	3,064	2,582	0	345	436	10,863
Hydro	531	661	620	30	3	3,676	2,280	0	7,801
Oil and other	130	400	45	1,788	243	0	20	207	2,834
Non-hydro renewable	101	445	242	234	418	0	146	2	1,589
Total	12,808	11,801	9,424	6,436	4,026	3,676	2,804	645	51,620

Source: EGA 08, ESAA. Chart 2-1. Includes total principal, embedded and non-grid generation capacity. Natural gas capacity includes coal seam methane.

Since 2004, around 3 GW of new generation capacity has been installed in Australia. This capacity has been predominately peak load plant, fuelled primarily by gas and to a lesser extent, non-hydro renewable generation.

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23 ABARE, (2007), Australia Energy: National and State Projections to 2029-30, Research Report 07.24, December.

24 Electricity Supply Association of Australia, (2008), Electricity Gas Australia, Chart 2.1.

3.1.3. Supply-demand outlook

To meet the anticipated 33 per cent growth in electricity demand by 2020[25], new base load electricity generation investment will be required. The 2008 Statement of Opportunities (SOO) projects that low reserve conditions (LRC) will occur as early as the summer of 2008-09 –Table 3.2. The LRC point indicates the first year that the reserve margin is projected to fall below the minimum reserve level. This does not necessarily indicate that capacity will be insufficient to meet expected demand, but it is a trigger for NEMMCO to investigate whether intervention to maintain power system reliability is required.

Table 3.2
Projected low reserve condition points[26]

Region	LRC Point	Reserve Deficit (MW)
Queensland	2013/14	267
New South Wales	2014/15	283
Victoria and South Australia (combined)	2008/09	168
South Australia	2010/11	16
Tasmania	2010/11	8

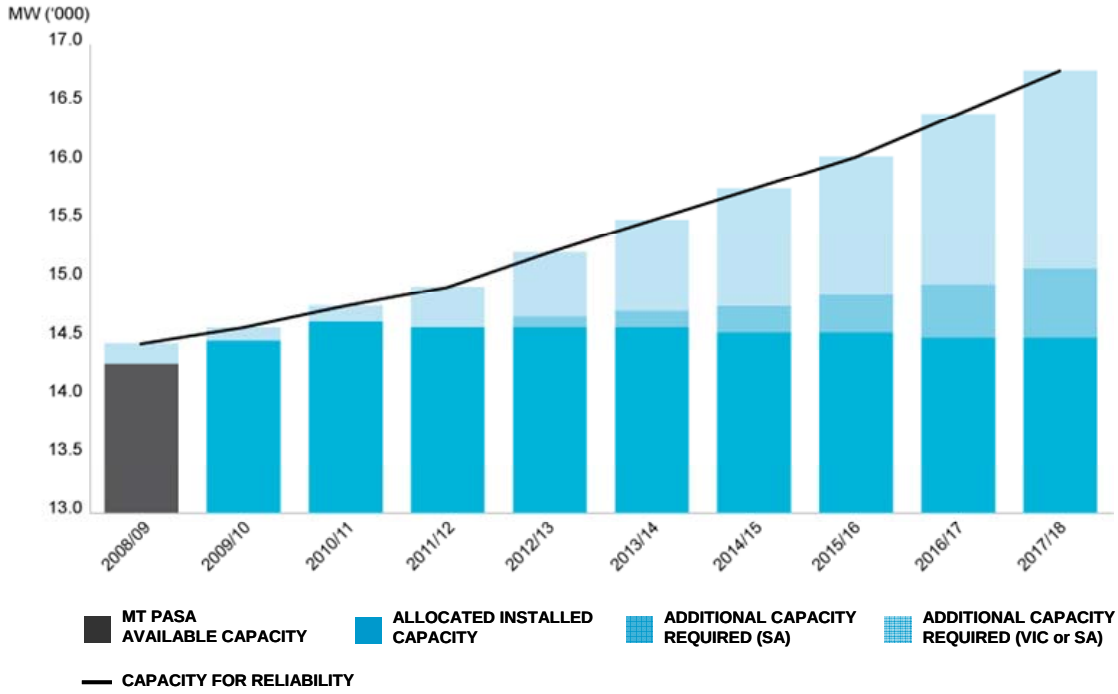
Victoria and South Australia will likely experience a 168 MW reserve deficit during the 2008/09 summer, Table 3.2, Figure 3.2. However, NEMMCO has indicated that it does not anticipate the need for market intervention (in accordance with reliability and emergency reserve trader processes) during this year because additional studies estimated that unserved energy will fall within the Reliability Standard.[27]

25 Using electricity consumption of 262 TWh for 2006-07 and ABARE's projection that demand will reach 349 TWh by 2019-20.

26 NEMMCO, (2008), Statement of Opportunities - Executive Briefing, October.

27 NEMMCO, (2008), Statement of Opportunities - Executive Briefing, October pg. 7.

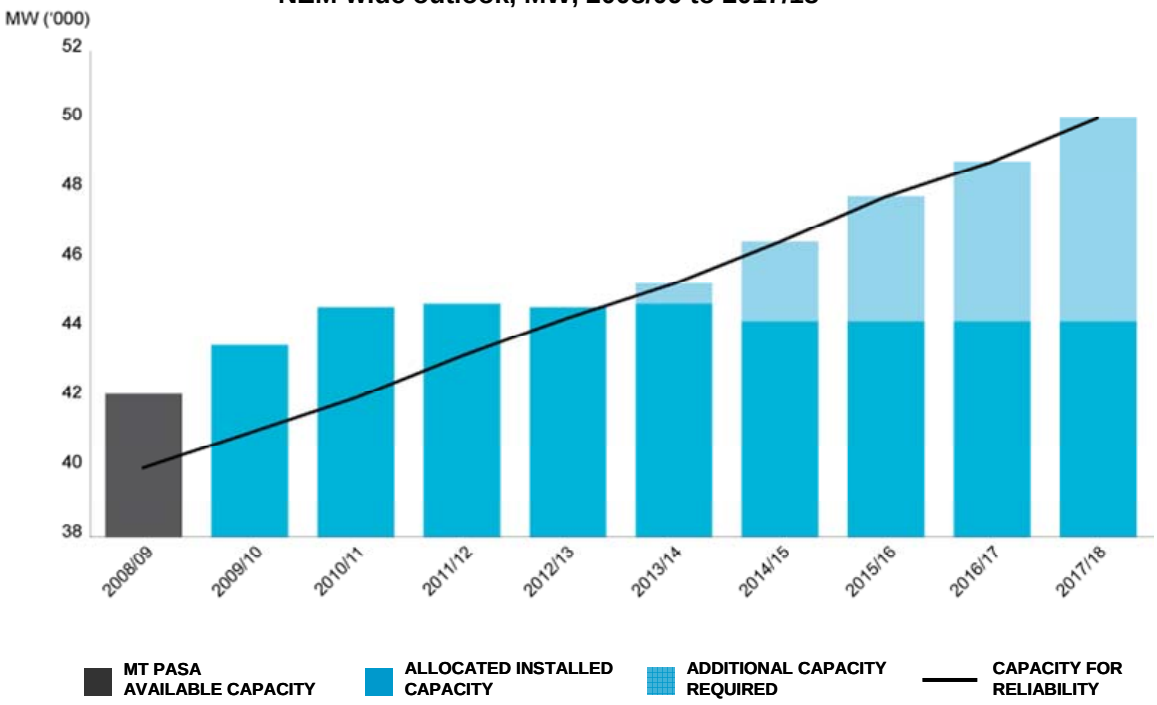
Figure 3.2
Outlook for Victoria and South Australia, MW, 2008/09 to 2017/18[28]



The NEM-wide outlook produced by NEMMCO represents an aggregate of the summer supply-demand outlooks for each region – 3. This indicates that additional capacity will be required in the NEM by 2013/14, and this requirement will grow significantly over the remainder of the outlook period.

[28] NEMMCO, (2008), Statement of Opportunities - Executive Briefing, October.

Figure 3.3
NEM-wide outlook, MW, 2008/09 to 2017/18[29]



Recently released Treasury modelling[30] of the impacts of a Carbon Pollution Reduction Scheme (CPRS) indicates that in the short term the electricity sector will substitute away from coal to gas and renewable fuel sources. Based on these modelling results, the share of gas in total generation at 2030 ranges from between 22 and 24 per cent in the policy scenarios (ie, with the CPRS in place) compared with 17 per cent in the reference scenario. However, incorporating the expended renewable energy target into the forecasts leads to the adoption of more renewable generation. This crowds out gas-fired generation and accelerates the transition away from coal, resulting in additional early retirement of existing fossil fuel power stations.

3.1.4. Issues affecting generation investment

The forecasts of electricity demand and the supply demand balance indicate that new base load generation investment is needed over the medium term. This is the first time in the brief history of the NEM that the market will need to deliver new base load generation.

There are two potential sources of uncertainty that are likely to be affecting new generation investment, namely:

- the introduction of a carbon pollution reduction scheme and a national renewable energy target; and
- developments in the gas market.

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29 NEMMCO, (2008), Statement of Opportunities - Executive Briefing, October.

30 Commonwealth Government of Australia, (2008), Australia's Low Pollution Future: The Economics of Climate Change Mitigation.

While climate change policies are being developed and are therefore necessarily uncertain, investment decisions will be deferred. Once these policies have been finalised and implemented, investors will be able to properly assess the implications of the policies for new generation investment.

In addition, developments in the gas market (outlined further in section 3.4 below) is likely reducing the availability of firm supply contracts as coal seam methane producers in Queensland prepare to supply proposed LNG facilities.

Removing these uncertainties will improve the potential for the market to deliver required base load generation capacity. Given these circumstances, the critical questions facing Australia are:

- What will replace coal generation as the primary electricity source in a carbon-constrained world? and
- When and how will this occur?

These issues are discussed in more detail in the following sections.

3.2. Australia's approach to managing climate change

Australia's reliance on emission intensive energy sources, and in particular its reliance on coal, means that Australia has one of the highest per capita greenhouse gas emissions in the world. Accordingly, the Australian government has announced a commitment to reducing greenhouse gas emissions by 60 per cent by 2050, compared with 2000 levels. To reach this target, the government has committed to introducing a carbon pollution reduction scheme (CPRS) and has proposed a national renewable energy target (national RET).

3.2.1. Carbon Pollution Reduction Scheme

Establishing a market for carbon emissions through the introduction of a CPRS is the central focus of Australia's climate change policy. A cap and trade CPRS places a cap on emissions[31], and then obligates emitters to purchase emissions permits, which provide a right to emit a volume of greenhouse gases into the market. The resultant price of permits represents the cost of emitting greenhouse gases, and should be equal to the marginal cost of either abatement or offset arrangements plus any associated transaction costs.

The CPRS will cover six sectors, namely: stationary energy; transport; fugitive emissions; industrial processes; synthetic greenhouse gas emissions; and waste. The government has also announced plans to include agriculture from 2015. Whether the forestry sector should be included, is still being considered.

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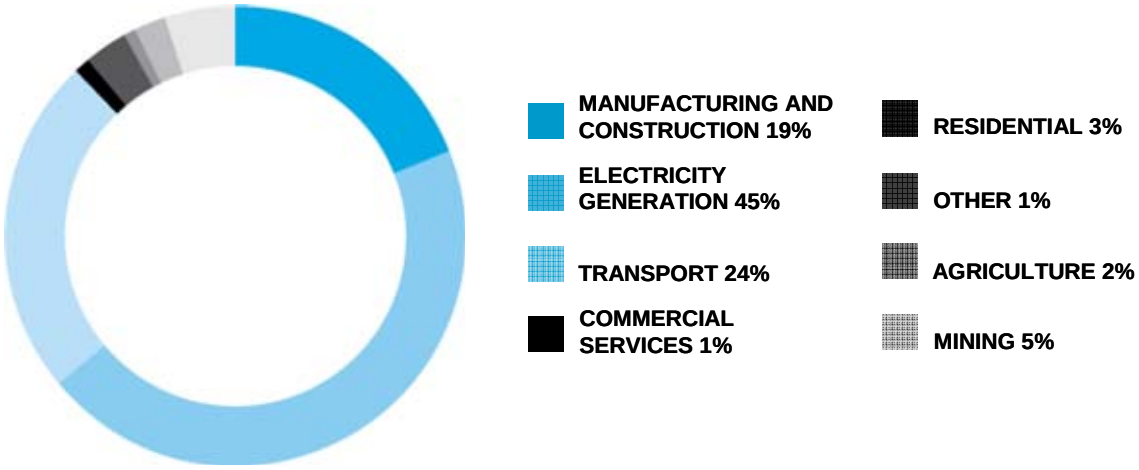
31 The Review proposes that the same six gases covered by the Kyoto Protocol should be covered by the ETS: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulphur hexafluoride (SF_6), perfluorocarbons (PFCs) and hydrofluorocarbons (HFCs).

Figure 3.4
Total primary energy consumption by sector, 2005-06[32]



The CPRS is proposed to commence in 2010. To assist in managing the introduction of the scheme, a price cap is to be applied, allowing emitters to purchase emission permits at a predetermined rate, thereby limiting the price of permits. The price cap is proposed to be applied until 2014-15.

To allocated emissions permits, periodic auctions will be conducted. However, to emissions intensive trade exposed industries and other strongly affected industries, the government is considering the allocation of free permits. The government has suggested that approximately 30 per cent of permits may be allocated freely during the initial period of the CPRS.

3.2.2. National renewable energy target

The national RET is Australia's national target for the supply of energy from renewable sources. The scheme, which was first introduced in 2001 as the mandatory renewable energy scheme (MRET), places a legal obligation on wholesale purchasers of electricity to proportionately contribute towards the generation of an additional 9,500 GWh of renewable energy annually by 2010. This liability is imposed by requiring purchasers of electricity (known as liable entities, ie, retailers) to purchase a set percentage of electricity from renewable sources.

In order to deliver the MRET objectives, generators are awarded Renewable Energy Certificates (RECs) when they generate electricity from renewable sources above and beyond their 1997 baseline.[33] Conversely liable entities are deemed to have a REC liability for every MWh of electricity supplied.

In December 2007, the Commonwealth and states agreed to bring the existing MRET and the various state-based targets into a single, expanded national RET scheme by

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32 ABARE, (2007), Australia Energy: National and State Projections to 2029-30, Research Report 07.24, December.

33 Small generating units and solar water heaters can be deemed eligible for a fixed number of RECs.

early 2009. The Commonwealth Government committed to increasing the renewable target from 9,500 GWh to 45,000 GWh in 2020 to ensure that the goal of a 20 per cent share for renewable energy in Australia's electricity supply is met by 2020.

The expanded national RET is to be phased out between 2020 and 2030 as emissions trading matures and prices become sufficient to ensure that an RET is no longer required to provide incentives for investment in renewable generation technologies.

3.3. Implications for the mix of generation

Electricity demand in the National Electricity Market is expected to increase by approximately 70 TWh in 2020 compared with current demand. This increase is likely to require new generation investment in the order of 8 GW. In the absence of climate change policies, the demand for new generation would most likely have been met through additional coal-fired generation on account of Australia's vast coal reserves and its low marginal cost. The introduction of the CPRS and national RET are expected to change the type and location of new generation investments, and accelerate the shutting down of generation from higher emission fuels such as coal.

The CPRS will create incentives to meet generation from lower emission sources (ie, gas), thereby leading to the likely partial redundancy of some existing coal fired generators. These incentives for gas investments will be partly lowered by the national RET creating incentives for renewable generation.

The expansion of renewable generation, in addition to the likely early redundancy of high emission coal generators means that future generation will likely be connected in locations that are significantly different to current generation. It is likely that by 2020, generation capacity could include:

- a large proportion from wind generation, located mainly in South Australia and Victoria;
- increased gas generation, dispersed within the network; and
- increased embedded generation, located in major urban centres.

This means that there will likely be a need for new transmission and distribution network investment to support the transfer of electricity from these new generation locations to major urban centres. This is considered further in section 4.

An expansion in the amount of wind generation providing electricity to the market has implications for its operation, particularly if it is concentrated in one or two NEM regions. For example, having a large proportion of intermittent generation in one region can lead to reliability problems in circumstances where demand is high, wind generation is unavailable, and inter-connectors are constrained. This means that there may need to be some reserve capacity available for these circumstances to satisfy reliability requirements.

Finally, the role of demand-side participation in the market, as an alternative to both generation and network investment is being closely examined. To date, demand-side participation has been passive within the market, as end-users respond to price signals within the usage charges they pay.

However, the Commission has been carefully considering whether there are impediments to the efficient uptake of demand-side measures, and whether changes should be made to the market to encourage its efficient development. Additionally, there has recently been a major exercise examining the costs and benefits of a national rollout of smart metering technologies, which would provide the information to facilitate improved demand signalling. Agreement has been reached to conduct trials of these new metering technologies, which are likely to be rolled out in some states over the coming years.

3.4. Implications for the gas market

The eastern Australian gas market is expected to undergo a significant transformation over the immediate future as demand for gas increases, both as a result of new gas-fired generation investments and from new LNG facilities.

The introduction of the CPRS will create incentives to shift generation away from high emissions sources such as coal into lower emission sources such as gas. Whilst the strength of these incentives will be lowered by the national RET, gas-fired generation and accordingly demand for gas is expected to grow substantially over the immediate future.

Similarly, the development of LNG facilities in Queensland has the potential to materially affect the development of the domestic gas market in both the short and long run. While it is expected that additional reserves will be developed to satisfy this new source of demand, it is unclear what effect this will have on domestic gas supply and therefore prices in eastern Australia.

Part of the uncertainty over future gas prices and supply can be attributed to the rapid growth in coal seam methane. This has dramatically increased Australia's gas reserves, creating the potential for gas prices to fall while also encouraging investment in LNG facilities. The overall implication for domestic gas prices remains uncertain.

3.5. Can Australia's energy only market deliver needed generation?

The central question facing the Australian national electricity market is whether the current market parameters provide sufficient incentive for efficient new investment in base load generation capacity?

Under the current market arrangements the incentive for new investment arises from generation returns exceeding marginal production costs by a sufficient amount to justify a new generation investment. This means that the wholesale electricity price needs to rise to a sufficiently high level to provide returns in excess of costs to create financial opportunities from new investment.

However, the current arrangements include a market price cap to limit market prices in order to manage price volatility risks, and reduce the potential for generators to exercise transient market power. In light of climate change policies and other market uncertainties, it is relevant to consider whether the current (and proposed) market price cap provides sufficient financial incentives to encourage efficient new generation investment.

So far, the current market price cap parameters have worked well. Investors have responded to the incentives created when prices are high during peak periods by investing mainly in peaking capacity. However, the real test will be whether the market can delivery the required new *base load* generation. Critical to this investment decision is expectations about the financial returns.

In circumstances where the market price cap is insufficient to provide the required financial returns, this suggests that either:

- the market price cap should increase to improve the financial incentives for new investment; or
- alternative capacity payment arrangements should be developed to ensure there is sufficient reserve capacity available.

Whether the market price cap is set appropriately, or whether alternative arrangements should be made is relevant to our current review of energy market frameworks in light of climate change policies, and is therefore under consideration.

4. Efficient network investment to support generation

This section focuses on the critical challenges for network investment in light of anticipated future changes to the mix of generation in the NEM. It starts by describing the network investment challenge, followed by a discussion of current investment and planning arrangements and the particular areas that require further attention.

4.1. The network investment challenge

In the absence of climate change policies, it is likely that new base-load generation needs would have been met by incremental expansion of generation capacity in locations adjacent to existing generation centres, eg, the Latrobe or Hunter Valleys. This means that augmentation of the transmission network to provide sufficient transfer capability to support the new generation capacity would have been most likely only an incremental expansion to the existing network.

The transmission planning and investment framework has been implicitly designed with this approach to network expansion in mind. This means the network planning and investment framework seeks to ensure that incremental expansions of the network, to maintain system reliability and security, occur in a least-cost manner. Primary responsibility for transmission investment lies with regional authorities, within a national framework for planning information sharing and dissemination.

However, climate change policies dramatically change the assumption that the network will expand in an incremental way. As highlighted in section 2, it seems likely that potentially large amounts of new generation capacity will be located in areas that are not well serviced with transmission capacity. There are two implications for the transmission network, namely:

- major extensions to the transmission network will be needed to connect new generation with the current shared network; and

- augmentations to the transmission network will be more significant, as the transmission flow paths change to transmit electricity from more disparate locations within the network, to the major load centres.

To better understand the extent of this network investment challenge, more detailed modelling of generation investment scenarios will be required. This is proposed to become part of the National Transmission Network Development Plan, published annually by the AEMO.

In addition to the implications for electricity transmission networks, there are also implications for the gas transmission network arising from an expected expansion in gas-fired electricity generation. These arise from differences in the approach to funding for network investment between each industry.

For gas, new transmission investments are usually underwritten by long term gas supply contracts that include a transportation component. A new gas generator that is seeking to locate in an area where there is insufficient pipeline capacity to provide firm access to gas supplies will therefore likely fund the pipeline investment needed to provide the firm access.

This contrasts with electricity where the generator is only required to pay for the direct costs associated with connection to the shared network, with the cost of any required shared network augmentation being shared amongst all network users. This difference in approach is sometimes identified as potentially creating a bias for generators to locate in areas where the pipeline costs are minimised, without regard to the potentially large the electricity transmission network augmentation costs that might be required to provide sufficient network transfer capacity.

This means that there is challenge to ensure that appropriate tradeoffs are made between gas network and electricity network investments. The materiality of this potential bias is considered further below.

In summary, the network investment challenge is therefore to ensure that:

- major network extensions are undertaken in an efficient way;
- transmission network augmentation and inter-connector investment is undertaken in an efficient way; and
- appropriate tradeoffs are made between gas network and electricity network investments.

4.2. Current investment and planning arrangements

The current electricity transmission investment and planning arrangements have been recently reviewed by the Commission and include:

- the establishment of a national transmission planning function in the newly formed AEMO;
- development of an annual national transmission network development plan (NTNDP) by the AEMO;

- annual planning reports, developed by transmission network service providers (TNSPs);
- application of an economic cost benefit analysis, called the Regulatory Investment Test for transmission (RIT-T); and
- primary responsibility for investment decisions resting with regional authorities, with the national framework providing a common information base.

The NTNDP will provide an annual strategic planning analysis of transmission network requirements, by considering network limitations and options for relieving them, in circumstances where transfer capability across the National Transmission Flow Paths is constrained.

In addition, the NTNDP will provide an analysis of forecast demand and supply conditions, and consider the implications of this forecast for the National Transmission Flow Paths.

The NTNDP does not affect the planning requirements placed on TNSPs to undertake annual planning reviews and make Annual Planning Reports, detailing planned investments in the network over coming few years.

Transmission investment is the responsibility of TNSPs, who are required to satisfy an economic cost benefit analysis before the cost of the investment will be rolled into the regulatory asset base for the purpose of determining transmission tariffs. The old test was known as the Regulatory Test and involved a different evaluation according to whether the investment was for the purpose of maintaining system reliability as compared to delivering market benefits.

The Commission has proposed that this test be replaced with a Regulatory Investment Test for transmission that removes the distinction in the old test between reliability and market benefits. The test involves identifying a preferred investment option that maximises the present value of the net economic benefits, subject to satisfying deterministic reliability standards.

4.3. Are changes to the current arrangements warranted?

The current and recently proposed changes to the transmission planning and investment arrangements go some way towards addressing concerns with the Regulatory Test and to satisfy a need for a more strategic and inter-regional network planning approach.

However, in light of the challenges for network investment presented by an expected change in the generation mix and its location in the NEM, there is likely to be a need for additional changes. Specifically:

- to expand the network planning and investment functions, in light of the need to provide major network extensions;
- to provide incentives for TNSPs to undertake network investments that benefit the market as a whole; and
- to allow tradeoffs between gas and electricity networks to be made.

Under the current framework, a new connection applicant would pay for the cost of the new major extension, where it is the first connection applicant with those costs being partially recovered from generators who connect subsequently. However, this promotes inefficient investment, by providing little incentive to optimally size the line to accommodate future connections or potentially encourage inefficient network duplication.

A spectrum of approaches for addressing this problem will be considered, ranging from market-based solutions to more directed planning solutions which may include, for example:

- 'open seasons' involving the auctioning of capacity in a proposed new transmission line and optimising the construction on the basis of interest in its capacity; or
- A cost benefit assessment of an extension and directing the relevant transmission business to undertake an investment where the expected benefits outweigh the costs.

Open seasons have been used in the US and have the effect of creating firm transmission capacity rights to the particular part of the network involved. Where only a single line is involved, this can be appropriate, although it would be necessary to consider:

- implications should the major extension become part of the meshed shared network in the future;
- implications of a major load wanting to connect to the major extension; and
- the treatment of transfer capability beyond the major extensions.

The alternative approach could be to undertake a cost benefit assessment of a possible extension, and in circumstances where the expected benefits are positive, direct the relevant TNSP to undertake the assessment. This approach directly addresses the lack of incentive TNSPs have to undertake major extensions to the network, passing the risk of these extensions onto consumers but involves regulatory assessment and direction to the investor by the planning body.

In addition to problems regarding major extensions to the shared network, the Commission has also identified problems resulting from the funding of transmission investment within a single NEM region. Specifically where transmission investment benefits accrue to another region, there is little incentive under the current transmission pricing arrangements for the investment to be undertaken. In fact there is probably a disincentive, because the investment would lead to higher electricity prices within the primary jurisdiction, with no associated benefits for consumers – an undesirable outcome for any jurisdiction when considered alone.

To fix this problem, the Ministerial Council on Energy has asked the Commission to consider developing a system of inter-regional charging. The aim is to provide incentives for each jurisdiction to undertake transmission investments that are in the interest of the market as a whole.

Finally, an expansion of gas-fired generation raises concerns about the potential for inefficient generation location decisions to be made because of differences in the charging approach for gas and electricity transmission investments. The problem arises because a gas generator needs to connect to both the gas pipeline network and the electricity transmission network. The contract carriage nature of gas pipelines means that any expansion of pipeline capacity that is required to provide firm access to a connecting generator needs to be paid for by the connecting generator.

In contrast, any electricity transmission network investments necessary to facilitate transfer capability for the new generator's electricity is paid for by all network users, so long as it satisfies the regulatory investment test. In principle then, generators would be expected to favour locating where gas pipeline costs are minimised, even though the total cost of doing so exceeds some other combination of pipeline and transmission network investment.

The materiality of this potential bias needs to be examined further, given that the cost of any necessary gas network investments it is only one factor that is likely to influence a proposed generator's decision to locate in a particular area.

5. Retail competition and its relationship to generation investment

Effective competition in the electricity retail sector is important to provide incentives to retailers to minimise wholesale generation costs, which in turn promotes efficient generation investment. This chapter briefly outlines the evolution of retail competition and its relationship to generation investment.

5.1. Evolution of retail competition

The retail sector has developed significantly over the past fifteen years, following the initial vertical separation of retail functions from other elements of the electricity supply chain as part of the first phase of energy reform. However, competition did not start to develop until the introduction of full retail competition (FRC) from 2002, which allowed customers to choose their electricity supplier.

FRC has been introduced in each jurisdiction in a phased approach, with large users having been given the first opportunity to choose their provider. Progressively smaller customers became contestable over time. Currently residential customers in all states and territories except Western Australia, the Northern Territory and Tasmania, are able to choose their electricity provider.

Despite the introduction of full retail competition, each state jurisdiction has retained its powers to determine regulated tariffs and/or conduct pricing oversight for small customers, while competition is developing.[34] For example:

- the Essential Services Commission of South Australia (ESCOSA) regulates a standing contract (price, terms and conditions) that the incumbent retailer, namely AGL, must offer customers consuming below 160MWh per year;35

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

- the Independent Pricing and Regulatory Tribunal (IPART) in New South Wales regulates the prices for small consumers of less than 160 MWh per year offered by the three incumbent providers, Country Energy, EnergyAustralia and Integral Energy;36 and
- the Essential Services Commission (ESC) in Victoria has reserve powers to regulate prices of electricity for those consuming less than 160 MWh per year.37

In 2006, each jurisdiction agreed to phase out all forms of energy retail price regulation in circumstances where competition is found to be effective.[38] The Commission has been tasked with assessing each jurisdiction to determine whether competition is effective. In undertaking these assessments, the Commission has been required to give consideration to the following criteria:

- existence of independent rivalry within the market;
- ability of suppliers to enter the market;
- the exercise of market choice by customers;
- differentiated products and services;
- prices and profit margins; and
- customer switching behaviour.

Once the Commission has assessed the effectiveness of retail competition, it must either recommend how price regulation should be phased out, or if it finds competition to be ineffective, it must make recommendations on how competition can be developed.

The Commission has so far conducted assessments of retail competition in Victoria and South Australia. In both cases the Commission found competition to be effective. In reaching this conclusion, the Commission found that:[39]

- customers were willing to participate in the competitive market when approached directly by a retailer, as evidenced by a significant level of customer switching;
- there was evidence of strong rivalry between retailers whom pro-actively market and vigorously compete for customers; and
- there were no apparent barriers to entry or exit within the retail sector, which might otherwise limit the future development of competition.

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

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

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

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

39 AEMC, (2007), Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in Victoria: First Final Report, 19 December, pg 94.

For the remaining jurisdictions, the Commission will undertake assessments of the effectiveness of retail competition.

5.2. Implications for generation investment

Retailers play an important role in the operation of the wholesale electricity market, by being the principal purchases of wholesale electricity. In order to manage wholesale price risk, retailers generally contract the majority of their load requirements with generators on a medium to long-term basis.

These contracts create an incentive for new generation investment. When contract prices rise, incentives are created for new generation investment at the point where expected revenue exceeds the cost of constructing a new generator.

Effective retail competition creates strong incentives for cost reduction, as each retailer seeks to improve its competitive advantage compared to its rivals to increase its market share. The strong incentive for cost reduction focuses retailers on lowering wholesale electricity costs. Once the national RET has commenced, retail competition will ensure that the cost of satisfying renewable energy targets is also efficient.

The focus on wholesale electricity costs under retail competition creates a strong incentive for retailers to contract for wholesale electricity at prices that are cost competitive. This means that contract prices are most likely to reflect the value of energy. This in turn leads to efficient generation investment.

For those jurisdictions where retail competition has not been found to be effective, then the regulatory framework for determining retail tariffs will still apply. In these circumstances, retailers face the potential for the regulator to not pass through wholesale costs that might be considered inefficient. This could result from the regulator's assessment of the factual circumstances given to it as part of its review.

Alternatively, the regulator might simply pass any additional wholesale costs through to customers in the form of higher tariffs, particularly where those costs are incurred in response to the national RET. This approach would certainly create lower incentives for the business to seek out wholesale cost efficiencies.

The effectiveness of the incentive for wholesale cost efficiencies plays an important role in providing incentives for efficient generation investment. As retail competition becomes effective in each jurisdiction, then new generation investment will more likely occur at an optimal time, as retailers seek to minimise wholesale costs and manage the risk of wholesale price volatility through contracts to supply load.

6. Conclusions

This paper provides an overview of the critical challenges currently facing the energy market, which have the potential to effect its development.

First amongst these is the need for the market to deliver significant new base load generation, in response to a deteriorating supply and demand balance in the short- to medium-term. While the energy-only market is expected to provide sufficient incentives for this to occur, the market parameters such as the market price cap may require modification, or alternative approaches may need to be more closely considered.

Second, an increase in the amount of intermittent generation in the NEM in response to the incentives created through the national RET brings into question the ability of the market to provide sufficient reserve capacity to satisfy the reliability standard. This suggests that alternative arrangements might need to be considered.

Finally there is a need to ensure that the network investment and planning framework provides appropriate incentives for efficient investment. This is to address the need to provide extensions and augmentations to the network to support expected renewable generation investment. There may be a need for adjustments to the current network investment arrangements to either provide stronger market based investment incentives or to provide greater direction to TNSPs from the newly formed AEMO in circumstances where a major network extension is found to be net market beneficial.

Ends