Australian Energy Market Commission

THE REFORM JOURNEY CONTINUES: ENERGY MARKETS AND CLIMATE CHANGE POLICIES

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The Reform Journey Continues: Energy Markets And Climate Change Policies

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1. Abstract

This paper explains why competitive energy markets are integral to the delivery of climate change goals in Australia, and considers whether the current frameworks for energy markets are likely to be up to the task of facilitating at efficient costs the implied transformation in where and how we produce and consume electricity. This transformation is expected to be driven primarily by the explicit pricing of emissions of CO2-equivalent gases through the Australian Government's Carbon Pollution Reduction Scheme (CPRS) and by the subsidising of investment in new renewable generation capacity through the expanded 20 per cent Renewable Energy Target (expanded RET). The paper describes the potential interactions between these policies and behaviour in energy markets, and discusses the ability of existing mechanisms in energy markets to promote efficient outcomes.

2. Introduction

Over the past fifteen years there has been substantial reform to the operation of Australia's energy markets. The reform process was strongly grounded in the principles of promoting competition and efficiency across the Australian economy. In 1995, National Competition Policy (NCP) was developed and adopted by the Commonwealth Government and all State and Territory Governments, and set out a program of reform to achieve its key principles. NCP was formulated following an independent inquiry into national competition, chaired by Professor Frederick Hilmer. From the perspective of the energy sector, there are two common themes from the evolution of these reforms over time. First, a transition from regional to national markets and rules. Second, a greater reliance on decentralised decision-making and competition to promote efficiency and protect the interests of consumers.

However, while the significance of these reforms should not be understated, it could be argued that the effectiveness of the reforms in meeting their objectives has yet to be fully tested in energy markets. While there have been significant improvements in the operating efficiency of generation capacity (as might be expected given the sharpened financial incentives provided by competition), the arrangements have not been "stress tested" considering the relatively benign starting position for the market. The current position is much more challenging, given the tighter supply and demand balance, increasing input costs, and the need for significant new investment if reliable supplies are to continue.

[1] The work of Colin Sausman, Lisa Nardi and Jacqueline Crawshaw in preparing this paper is gratefully acknowledged.

Further, the underlying cost structure of the industry has been remarkably stable. Australia's large reserves of coal continue to underpin around two-thirds of our generation capacity. The introduction of the climate change policies which price carbon emissions and subsidise investment in renewable generation capacity represent large "shocks" to the underlying economics of the industry. Our cheapest generation capacity is also our most carbon-intensive – and relatively modest carbon prices (in the range $20 to $30 per tonne) will begin to alter the pecking order between coal and gas substantially.

Taken together, these factors make for a dynamic and challenging time for Australia's electricity supply industry – with the outcomes critically important in terms of maintaining reliable supplies to business and communities while meeting the policy goals on climate change.

The primacy of the electricity supply industry to the task of reducing Australia's carbon footprint is unquestionable. Electricity generation currently accounts for more than 50% of Australia's emissions. Many of the policy responses to climate change will be designed to reduce the greenhouse gas intensity of electricity generation and ensure that electricity is used more efficiently.

3. The Australian Energy Market Commission (AEMC)

The AEMC is an independent statutory body, comprising three Commissioners and supported by a staff of forty people. We are based in Sydney and have a national role. Our formal statutory role spans two key functions. First, we are the Rule maker for the National Electricity Market (NEM) and for aspects of the rules for gas markets. Second, we are responsible for market development. We undertake this latter role in a variety of ways. The most significant, and germane to the issues discussed in this paper, is our role to review issues and provide advice to the main policy-making body, the Ministerial Council on Energy (MCE).

In undertaking all of our functions we are required by law to have regard to the National Electricity Objective (NEO):

> *"to promote efficient investment in and efficient use of electricity services for the long term interests of consumers of electricity with respect to (a) price, quality, reliability and security of supply of electricity; and (b) the reliability, safety and security of the national electricity system."*

The AEMC can only make a Rule where it is satisfied that it meets the National Electricity Objective. This objective also guides all of our work on electricity market development.

Turning to the specific issues discussed in this paper, in July 2008 we were directed by the MCE to review whether energy market frameworks could be expected to continue to promote outcomes consistent with the NEO following the introduction by the Australian Government of a CPRS and expanded national RET. We recently published our 1st Interim Report on this Review. We are therefore well placed to set out our current thinking on where the stress points may lie. We will report our findings and recommendations to the MCE in September 2009.

This paper provides a snapshot of our current thinking. It discusses the strengths and risks associated with these new policies under the existing market frameworks from three different perspectives: electricity generators; the network businesses whose role it is to provide the networks to transfer power from producers to consumers; and electricity consumers. We preface this with some context on the structure and performance of energy markets, how the CPRS and expanded national RET work, and how they intersect.

4. The Electricity Supply Industry

The electricity produced by generators is fed onto the high-voltage transmission network. The transmission network transports power to local distribution networks for onward delivery to end users. Some smaller generators are connected to distribution networks and some very large customers are also connected directly to the transmission network.

Overlaying this physical system are a series of contractual relationships. There are regulatory frameworks for most of these sets of contractual relationships. These are explained in more detail in the sections that follow.

Overview facts

- The NEM was established in 1998.
- It is a single market for wholesale electricity covering the interconnected network from Cairns to Port Lincoln, and to Hobart.
- In 2007/08, electricity valued at over $11 billion was traded through the NEM.[2]
- There are around 275 registered generators, with total output of over 200 thousand GWh – serving 13 major distribution networks, and 8.7 million customers.

4.1. The wholesale market

4.1.1. The spot market

The NEM wholesale market is a mandatory "gross pool". All energy produced by generators above 30 MW who are connected to the grid has to be sold through the pool. A price per MWh is calculated for each of the five regions (Queensland, New South Wales, Victoria, South Australia, and Tasmania) every 30 minutes.

Generators receive payments from the pool, and retailers and some large customers pay into the pool. The payments received by generators depend on how much energy they produce in each trading interval. Generators do not receive payments for making capacity available. This is known as an "energy-only" market design.

The NEM Management Company (NEMMCO) is the market and system operator. This involves determining which generators are dispatched to run in each 5-minute

[2] Source – AER, State of the Energy Market, 2008 p.77.

dispatch interval to meet demand. It also involves calculating electricity prices in the market every 30 minutes, and managing the process of financial settlement based on production and consumption volumes at the prevailing prices.

Prices reflect the marginal cost of supply at the main load centre in each region, based on the costs revealed through generator bids. Prices can be very volatile in the spot market, moving from tens of dollars to thousands of dollars in a matter of minutes. The maximum price is $10 000 per MWh. The minimum price is -$1000 per MWh.

In order to keep frequency on the network within acceptable tolerances around 50 Hz at all time NEMMCO has to call on additional (ancillary) services. These are procured through a separate Frequency Control Ancillary Services (FCAS) market which is also operated centrally, in parallel to the spot market. These services generally involve small, but precise adjustments to a generator's output. NEMMCO issues dispatch instructions every 5 minutes to minimise the joint cost of providing energy and FCAS.

4.1.2. The contract market

Price uncertainty and volatility creates significant risk for generators and retailers. The contract market provides tools for both parties to manage these risks and also underpins most generation investments. The contracts traded in the contract market are derived from and generally referenced to pricing outcomes in the NEM. Although the contract market itself is outside the Rules applying to the NEM, it is subject to financial services regulation.

There are two core types of contract; a "swap" contract, which trades a volume of electricity at a specified time and location at a fixed price; and a "cap" contract which trades "insurance" against very high price events (e.g. over $300 per MWh) in the spot market. In broad terms, swap prices signal the value of energy and cap prices signal the value of capacity.

4.1.3. Inter-regional Settlement Residues (IRSRs)

Prices in different regions in the spot market can diverge, e.g. as a result of transmission constraints between regions. Generators and retailers who contract across regional boundaries therefore face a price risk for contracts which are referenced to a region other than the one they are located in.

If electricity flows from a lower priced to a higher priced region, then a "settlement residue" accrues to NEMMCO. This means NEMMCO receives more money from retailers in the higher priced region than it needs to pay out to generators in the lower priced region. NEMMCO holds periodic auctions to sell claims on these Inter-Regional Settlement Residues (IRSRs). This provides a tool for market participants to hedge the risk of price separation between regions.

4.2. Transmission networks

The ability to use ("dispatch") different generators to meet demand depends on available network capacity. In a competitive market, the behaviour of network businesses therefore plays an important role in influencing outcomes in the market.

The behaviour of networks should be regulated to be stable and predictable. It should be responsive to the needs of the market, but should not "crowd out" or distort market investment.

If network capacity is scarce, then the Rules governing how the available capacity is shared out become increasingly important. In the NEM, no generator has a prior claim ("access right") to scarce network capacity. Capacity is allocated to the generators who are dispatched, i.e. the mix of generator which meets demand at least cost given the available network. The allocation of rights to use the transmission network therefore changes every five minutes based on the dispatch. There are provisions in the Rules to allow generators to negotiate with a Transmission Network Service Provider (TNSP) to provide access rights, but these have not been used significantly to date.

The costs of each generator connecting to the shared network are negotiated bilaterally with the relevant transmission business. The costs are borne by the connecting generator. The costs of building and operating the shared network are dis-aggregated to the level of each regional transmission company and recovered through charges to customers in that region.

The revenues and pricing of each transmission business are subject to periodic review by the Australian Energy Regulator (AER), applying a framework defined in the Rules. This involves setting a cap on revenue for the coming five years, and approving a pricing methodology. The ability to deliver network services at costs lower than those assumed by the regulator in setting allowed revenues provides a financial incentive for network businesses to minimise costs. The regulatory framework also allows for the regulator to design additional incentive schemes linked to particular output measures, e.g. network availability. These scheme are capable of boosting revenues by up to 5 per cent for very strong delivery against the output measures, and reducing revenue by up to 5 per cent for under-performance.

In addition, transmission businesses have obligations under the Rules to consult on their investment plans. The obligations are more demanding for large investments, and require detailed consultation and assessment (the "Regulatory Test").

There is also scope for unregulated market network services. Three major unregulated transmission investments have been made. Two subsequently converted to regulated status. Basslink, the high voltage DC sub-sea link between Tasmania and the mainland, continues to operate as an unregulated link.

4.3. Distribution networks

Distribution networks are the lower-voltage networks that link the transmission system to individual homes and businesses. There are smaller generators connected to distribution networks, and the volume of this type of generation is increasing over time. One consequence of this development is the need for more active management of electricity flows across distribution networks.

There are fifteen major electricity distribution networks in Australian, thirteen of which are in the NEM. There is a mix of private and public ownership, and one example (Australian Capital Territory) of joint public/private ownership. The total regulatory value of these networks is approximately $27 billion, which is approximately twice as large as the comparable value for transmission networks. Consequently, distribution costs represent a significant proportion (approximately 30% to 50%) of a typical residential electricity bill.

The revenues and pricing of distribution networks is regulated by the AER under a framework defined in the National Electricity Law. The framework is broadly similar to the framework used for transmission. It involves periodic assessments of forecast efficient costs, and recognition of financing costs for past investment. There is a degree of variability in how this broad framework is translated into regulated prices or revenues. For some businesses it is expressed as a cap on (weighted average) prices. For other businesses it is expressed as a cap on total or average revenue. There is also variation across businesses in the use of incentive mechanisms, although all business are subject to some form of performance monitoring against defined performance measure. These variations in regulatory approaches reflect the decisions taken by the previous jurisdictional regulatory bodies.

The investment planning followed by the distribution businesses also varies across businesses. The MCE has recently directed the AEMC to provide advice on how to define standard regulatory obligations in the Rules, including a role for Annual Planning Reports similar to transmission businesses.

4.4. Retailing and consumption

Regulation

Retail markets, like wholesale markets, are characterised by decentralised decision making and competition within an overall set of market Rules. Wholesale energy costs are a significant component of retailer costs. Retailers typically firm up their wholesale prices through derivative contracts with generators. These contracts also reduce risk for incumbent generators and potential investors.

Retailers’ revenues are dependent on electricity sales. Retailers compete to retain existing and attract new consumers. Levels of customer churn in some states have been high by international standards. Retailers are also subject to price and other regulation at state level.

The AEMC has an ongoing task from the MCE to review the effectiveness of competition in each state with a view to removing price regulation if and when competition is effective. We have completed the reviews for Victoria (in 2007) and South Australia (in 2008) and concluded that competition is effective in both regions. The Victorian government recently legislated to remove price regulation. The South Australian government is currently considering our final report which recommended replacement of the current price regulation arrangements with a price monitoring regime.

Consumers

Most mass market consumers have meters which read cumulative consumption rather than half-hourly consumption. This limits the types of offers that retailers can make – and reduces the ability to reward consumers financially if they manage their consumption in ways that avoid costs (e.g. of procuring electricity at times of very high prices, or of re-enforcing the network to serve demand at times of system peak).

There are, however, plans to roll out more sophisticated, “smart” meters. These may enable more targeted time of use price signals to consumers and more flexible ways of managing load at times of peak demand.

A number of larger consumers have contracts which provide incentives to manage their demand more actively. For example, aluminium smelters – which have very electricity-intensive production processes. This can occur by a large load participating in the spot market like a generator. It can also occur through contracts with retailers or network businesses. For retailers, it can represent an alternative means of managing exposure to high prices. For network businesses, it can be a means of reducing the need for network investment.

5. Market performance

The NEM’s performance since commencement has been generally strong. The market design is viewed favourably internationally, and technical performance has been generally sound. There have been relatively low prices and solid performance in terms of reliability.

5.1. Reliability

The target level of reliability is a long-term average of not more than 0.002% of unserved energy[3] due to insufficient capacity – in each region of the NEM, and across the NEM as a whole. This standard is within the range of comparable standards in other developed economies. The choice of standard represents a policy discussion as to the acceptable trade-off between cost and reliability, given that it would be prohibitively expensive to make electricity supply 100 per cent reliable for all customers.

Prices in the spot and contract market provide the economic signals for new investment to meet the reliability standards. The expectation of high prices in the spot market indicates whether and where new investment might be economically viable. Spot market prices can go as high as $10 000 per MWh currently – and there is currently a proposal in front of the AEMC to increase this to $12 500 per MWh. There are also emergency provisions for NEMMCO to procure capacity reserves. These mechanisms are discussed in more detail in section 8 below.

Unserved energy events are very rare. The most recent events were in Victoria and South Australia on 19 and 20 January 2009. Over the two days, the amount of unserved energy represented around 0.004% of annual energy in Victoria. The comparable figure in South Australia was 0.032%. A repeat of these events every two years would not be inconsistent with the standard.

The reliability standard measure excludes loss of supply due to network security incidents. Transmission businesses have their own reliability standards in respect of planning investment to meet desired levels of network reliability. These are set individually by each jurisdiction – although there are moves to harmonise and increase the transparency of the frameworks for setting standards.[4] Victoria and

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[3] Unserved energy is the amount of energy that is demanded, but cannot be supplied, in a region.

[4] The AEMC provided advice to the MCE on this matter in September 2008.

South Australia also experienced loss of supply due to network security concerns on 29 and 30 January 2009.

5.2. Investment

Generation capacity

In the last ten years, over 14 700 MW of fossil fuel powered electricity generation capacity has been installed, or is currently under construction. Of this, 77 per cent is in the NEM and 23 per cent is in Western Australia. This represents an annual average investment of around $400m (in 2008 prices). The private sector has been responsible for approximately 67 per cent of the new installed capacity.

New gas-fired generation accounts for around two-thirds of the total new capacity. The majority (40 per cent) is Open Cycle Gas Turbines (OCGT). This is peaking plant, designed to operate for relatively few hours each year. The remainder (25 per cent) is Closed Cycle Gas Turbines (CCGT), which is more amenable to intermediate or base-load operation.

Black coal-fired generation accounts for 25 per cent of the new capacity over the period. There has been no new brown coal plant, although upgrade of existing plant in Victoria has delivered an additional 400 MW of capacity.

Networks

The transmission network to service the NEM comprises nearly 50 thousand kilometres of high voltage lines. Capital expenditure on the transmission network has more than doubled over the last three years from $759m in 2005 to $1580m in 2008.[5] This represents an investment of $4.3 billion in the transmission network between 2005 and 2008, focused primarily in New South Wales and Queensland.

The lower voltage distribution network is much longer than the transmission network, at over 767 thousand kilometres of lines and cables. As with the transmission network, investment has been greatest in New South Wales and Queensland – with each state investing around $3 billion in their respective distribution networks over the past three years.

The gas network has also expanded substantially over recent years, reflecting the growing use of gas for power generation and for space and water heating. Between 2000 and 2006 approximately $2.5 billion was invested in high-pressure transmission pipelines through expansion and new build. This represents approximately 6000 kilometres of new transmission pipelines. There has also been substantial growth in the lower pressure distribution pipeline network – around $8 billion (in 2008 prices) between 1997 and 2006, providing 9000 kilometres of new network.

5.3. 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

[5] In nominal prices.

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.

The prices charged to the smallest customers by retailers have historically been regulated. In 2006, each jurisdiction agreed to phase out all forms of energy retail price regulation in circumstances where competition is found to be effective.[6] The Commission has been tasked with assessing each jurisdiction to determine whether competition is effective.

6. Climate change policies

6.1. Carbon Pollution Reduction Scheme

The Australian Government has announced the introduction of a national CPRS by 2010 as a key component of its climate change policy.

The CPRS will require businesses that emit more than 25 000 tonnes of carbon dioxide equivalent gases ($CO2$ -e) per annum as part of their industrial processes to pay for the right to do so. Businesses will demonstrate that they have complied with this requirement by buying and surrendering permits, and will be subject to periodic audits. If businesses do not surrender permits equivalent to their emissions they may be subject to a financial penalty.

The quantum of permits released for sale over time will reflect the Government's target level of carbon pollution reduction. Permits will be released for sale through an auction. Some permits are to be allocated free-of-charge to specific sectors as part of transitional assistance packages. Carbon-intensive coal-fired generators are one such sector. Businesses will be able to buy and sell permits on the open market. The price of permits will be determined by their scarcity and by any regulated price limits. The scarcity of permits will be influenced by the trajectory of the emissions reduction target, and any ability to bank or borrow permits. The permits will be released for sale by an independent regulator established by the Australian Government.

The CPRS is based on the concept that the cost of carbon emissions should be factored in to economic decision-making, and that trading in the right to emit carbon will, over time, result in targets for carbon reductions being met at least cost. This is because the CPRS will create financial incentives that reward lower-emission processes, and over time the processes that can reduce emissions most efficiently will be the ones that reveal themselves to be most profitable in the market. The policy does not need to identify what those processes might be in advance.

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6 For more information, see the COAG website: www.coag.gov.au/meetings/100206/index.htm.

6.2. Renewable Energy Target

In 2001, a mandatory Renewable Energy Target (MRET) scheme was introduced by the Australian Government to increase the uptake of renewable energy in Australia's electricity supply and to reduce greenhouse gas emissions. The initial target was to supply 9500 gigawatt-hours (GWh) of renewable energy per year by 2010.

In 2007, the Australian Government announced its commitment to ensuring that 20 per cent of Australia’s electricity supply comes from renewable sources, that is approximately 60 000 GWh by 2020. The commitment included: increasing the existing MRET to 45 000 GWh and consolidation of the existing state-based target schemes into a single, national scheme. The Australian Government has also announced an intention to phase out the scheme between 2020 and 2030 as the CPRS matures. There are presently two main design options, for the expanded RET under consideration, which imply different profiles for change over time.

The expanded RET is similar to the CPRS in that part of its rationale is to reduce greenhouse gas emissions. However, it differs from the CPRS because it provides market incentives to accelerate the uptake of specific low-carbon technologies such as wind, solar and geothermal energy.

The policy is specific to electricity markets, and is given effect through an obligation on electricity retailers and large users to procure a set proportion of certificates from renewable based generation each year. The required proportion (of each retailer and large users electricity demand) increases over time consistent with meeting the target. Each megawatt hour of energy produced by an eligible renewable energy generator attracts a Renewable Energy Certificate (REC). Generators can sell these certificates to retailers (either bundled with the electricity, or separately). The RECs are proposed to be bankable.

Retailers can comply with the obligation by either surrendering the appropriate volume of certificates or paying a “buy out” price for any deficit. The “buy out” price is regulated, and is $40 for the existing mandatory scheme of 9500 GWh.

7. The transformation of Australia’s energy markets

The main theme of this paper is to consider whether our current energy markets (as described above) are capable of transitioning to a significantly lower carbon-intensity effectively and efficiently. In the analysis below we consider this question from three different perspectives: generation, networks, and consumers.

Our over-arching finding is that the frameworks are broadly resilient to the challenges of this task in the NEM. There are, however, a small number of key risks where careful consideration of options for change is required. These relate to:

- Managing reliability in the short term, given prevailing tight supplies in some regions through the early years of this transition;
- Providing regulated networks and generators with the right signals to connect large-scale remote renewables efficiently; and

- Enabling the efficient costs of the CPRS and RET to be reflected in bills to customers – and empowering consumers with the ability to respond.

The detailed reasoning underpinning these over-arching findings is discussed in the three sections that follow. These preliminary findings are now open for public consultation. Stakeholder submissions on these issues will help test these preliminary findings - and inform the next phase of our review to identify and assess potential options for change.

8. Transformation in generation capacity

8.1. Objective

Energy markets will have stood up well to the task of transforming to a lower carbon generation fleet if new investment, changes in mode of operation and plant retirement is delivered efficiently and without putting at risk the desired standards of supply reliability.

Efficient delivery should be through decentralised decision-making in competitive markets, with the role of governments and policy-makers being limited to setting (and refining) the frameworks for competitive markets to operate.

8.2. Impacts on generators

8.2.1. CPRS

The key areas of impact on generators from the CPRS are as follows:

- Generators will reflect the cost of carbon into their spot market offers. This will increase prices in the spot market. The additional risks around the cost of carbon may also increase volatility. The impact on spot market prices will reflect the carbon-intensity of the price-setting generator.

- The carbon price will likely flatten the merit order, since it increases the cost of cheaper high emissions plant (e.g. coal) more than the cost of low emitters (e.g. gas). This might be expected to reduce variability in the spot price.

- The carbon price should change the merit order such that low emissions plant should increase output to displace high emissions output. This may provide complications for existing coal plant, which is not suited to running flexibly and less frequently. The risk of plant failures may increase consequently.

- Generators may have reduced incentives to enter into long-term swap contracts to hedge their financial risk – this is because carbon costs are likely to represent a large proportion of variable costs for most generators.

- The profitability of carbon-intensive generators will be materially reduced. At higher carbon prices it will become cheaper to build new low emissions plant to replace existing high emissions plant. On the basis of current gas prices, this is likely to occur at prices of around \$30-\$45/tCO_2 for brown coal plant and at marginally higher prices for black coal plant.

- The carbon price will increase investment in low emissions plant. This might be dampened by slower demand growth, to the extent that higher electricity prices result in lower demand for electricity. The location of gas investments should be more flexible than coal due to the greater potential to transport gas. This may see plant locate closer to major load centres.

8.2.2. RET

The key areas of impact on generators from the RET are as follows:

- There will be a significant increase in investment in renewable generation. The majority of this is anticipated to be wind generation due to its cost advantage relative to other available renewable technologies. An ability to bank RECs (as proposed) tends to promote earlier investment (in wind). Modelling has forecast approximately 8000 MW of new renewable plant by 2020 to meet this target.[7]

- Wind generation tends to be remotely located due to locations of the best wind resources. Hence there will be more generators seeking connection to remote (or non-existent) parts of the transmission network.

- Wind generation has low running costs because fuel costs are, in effect, zero. It will therefore generally be dispatched ahead of other forms of generation. Increases in the expanded RET target over the course of the scheme are largely consistent with anticipated increases in demand over time. This means that more new renewable plant will be built to meet growing demand rather than to displace existing thermal.

- There will be an increase in investment in flexible, "peaking" gas-fired generation to complement the intermittent nature of wind-farm output. This will be a response to the more volatile prices that would prevail otherwise, including at times of potential capacity shortfalls when the wind resource is unavailable (e.g. on hot, still days).

8.3. Strengths of current framework

The current framework has delivered significant volumes of privately-funded new generation capacity. The dominant view among industry stakeholders is that the current frameworks are capable of delivering the required, much larger volumes of new investment implied by the CPRS and expanded RET. There are substantive reasons for this which reflect the underlying robustness of the market design choices made at the start of the market in 1998.

The role of market signals

The "energy-only" spot market provides a continuous stream of price information in each region as to the value of capacity. It also provides a continuous stream of information on the underlying bids and offers made by market participants.

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[7] McLennan Magasanik Associates, Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets, 2008, figure 3-6, p.39.

Market participants enter contracts, either swap or cap contracts, in expectation of what spot prices will be. The value of these financial contracts (revealed in transactions, or implicit within a single business) provides sophisticated signals as to the capacity and the energy delivered to the market by generators.

While the introduction of the CPRS and expanded RET will alter the size and form of these market signals, there is no reason to conclude that the accuracy of the signals will diminish. Nor is it clear why the ability of market participants to respond to those signals is diminished by the introduction of the CPRS and RET. Arguably the more dynamic environment creates new business opportunities. The separate signalling of the value of energy and capacity is critically important in the context of the expanded RET because of the low contribution that wind generation makes to reliable capacity at system peak. The planning body in South Australia assumes a contribution of less than 10 per cent despite the average contribution over the year being more like 30 per cent.

The role of regulation

The value of financial contracts derived from the spot market is significantly influenced by the maximum price permissible in the spot market. To illustrate, a cap contract will be more valuable if it insures against maximum prices of $20 000 as compared to $10 000. This maximum price is regulated. Therefore, the process about how the maximum market price is set is of critical importance to the ability of the market to deliver capacity consistent with required standard of reliability of 0.002% unserved energy.

In the NEM, the AEMC Reliability Panel has a defined role to review the market settings from the perspective of reliability, and propose changes when necessary. The proposed changes are assessed against the market objective, and implemented if the AEMC considers the change will promote the market objective. This is a robust framework, and appears to work effectively in practice. An example of this process is the analysis and consultation undertaken through the Reliability Panel's Comprehensive Reliability Review (CRR), which concluded with a Rule change proposal in December 2008 to the AEMC to increase the Maximum Market Price from $10 000/MWh to $12 500/MWh with effect from 1 July 2010. The AEMC is currently considering this proposal.

The role of system operation

The system operator, NEMMCO, translates the 0.002% reliability standard into Minimum Reserve Levels (MRLs) for each region. The publication of these MRLs in the annual Statement of Opportunities informs the market on future capacity needs.

In the shorter term, NEMMCO has a more active role. If actual reserves are forecast to fall below the MRL, then more detailed analysis is undertaken to establish a more accurate probability of the reliability standard being breached as a result of insufficient capacity. If this is the case, then NEMMCO can contract for reserves. This "Reserve Emergency Reliability Trader" (RERT) power can only be invoked nine months ahead of time, and excludes capacity that is already in the market. Its focus is therefore high-cost capacity. This may include demand-side response and small-scale embedded generation.

Ideally, the RERT is never needed. However, it does provide a safety net at times of extremely tight capacity margins. The costs of RERT are potentially very high, e.g. if it attracts new capacity which is not currently in the market because it is uneconomic at $10 000 per MWh. NEMMCO requires the consent of the relevant jurisdiction before additional reserves are procured.

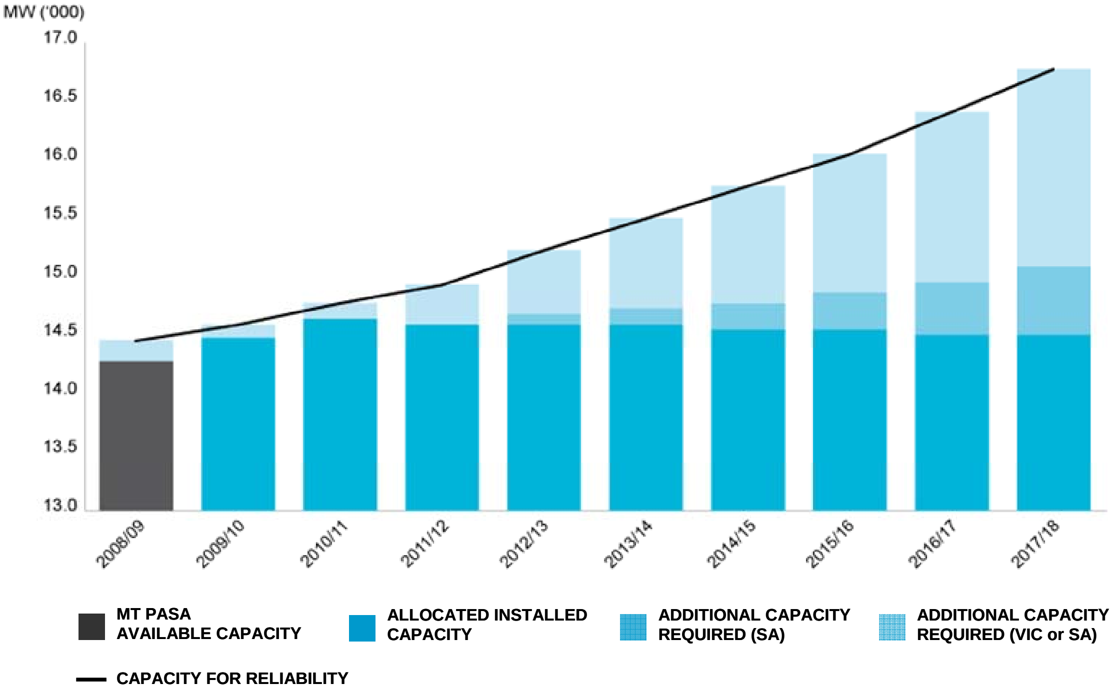
8.4. Risks within the current frameworks

There are, however, a number of important heightened risks or pressure points that might be revealed through the implementation of CPRS and expanded national RET. There are also factors in the wider environment that could adversely impact on the speed and efficacy of the transformation in generation.

Investment lags and managing short-term reliability

In the short term, for a variety of reasoning including market uncertainty over the precise form of government policy on climate change over the past few years, we have tight generation margins in some regions. This is most evident in Victoria and South Australia, as illustrated by Chart 1 below from NEMMCO's 2008 Statement of Opportunities.

Chart 1: Outlook for Victoria and South Australia, MW, 2008/09 to 2017/18



While new investment is planned, we will only see the effect with a lag. The potential disruption this can cause was illustrated on 29 and 30 January 2009 in South Australia and Victoria, where available capacity was one (of a number) of the factors contributing to temporary losses of supply. Extreme weather conditions impacted both the level of demand and the energy delivery capacity of the supply side of the market. Transmission and distribution outages were also significant contributing factors.

While infrequent events such as these are consistent with maintaining the existing reliability standard in the long term, it is important to review whether the "tools" available to the system operator in managing such situations are fit-for-purpose, and being used on the basis of the most accurate available information. This is an area where we had already identified potential scope for improvements. However, such reforms need to be carefully balanced with the risk that system operators become too intrusive, such that their actions distort the market.

In this context, we are currently assessing whether NEMMCO's powers to intervene to procure additional reserves need to be refined or complemented. This could potentially involve improvements to the information available to NEMMCO in determining whether or not intervention is required. It could also involve greater flexibility over how far ahead of real time NEMMCO is permitted to procure additional reserves.

Performance of existing capacity during transition

The process of fuel-switching from coal to less carbon-intensive forms of generation will reveal itself through changes in the operation of existing plant, and through new investment. Changing the operation of existing plant is not without risk. Coal-fired generation is designed to be in continuous operation, with limited changes in output. Increasing carbon prices will put pressure on this mode of operation. For a period of time it will be economic to keep the plant in service but run it less frequently. There is a heightened risk of plant failure during this phase.

Any consequent large, unplanned outages (or early retirement, if an emerging technical fault is uneconomic to repair or cannot be financed) are likely to put additional pressure on the existing mechanisms for managing reliability in the short term, given the limited ability to accelerate generation investment plans – with potential costs and risks for market participants and energy consumers.

Wider financial environment

The CPRS and expanded RET imply very large generation investment programs by past standards. Some analysts estimate that meeting the expanded national RET requires average annual investment of $2.3 billion, with a further $700 million to $1 billion per year on new thermal plant to replace coal-fired generation retirements. There will also be implications for investment in energy networks. Expenditure on regulated electricity transmission networks over the last three years has averaged around $1.4 billion. Forecasts suggest that this expenditure will continue or may increase.

Recent developments in financial markets make this task more challenging than it otherwise would be. Australia is a significant net importer of capital, and adjustments by international banks in their appetite to lend in Australia may have significant implications for the speed of the adjustment.

The current financial environment could also have implications for the financial viability of existing plant. The introduction of relatively modest carbon prices through a CPRS result in a significant impairment to the value of existing plant. This has been recognised through the Australian Government's planned Electricity Supply Assistance Scheme (ESAS), which proposes to provide $3.5 billion of assistance to the most carbon-intensive generation plant. This materially reduces the risk of immediate financial distress and the consequent operational and commercial uncertainties associated with businesses being in insolvency "work outs".

Economic signals to guide location of new investment

The CPRS and expanded RET will result in more generators entering the market. The RET will trigger new investment in wind generation. This in turn will trigger investment in new peaking plant to provide capacity to back up the wind generation at times when it is not running. The CPRS will, in the medium term, accelerate the rate at which coal plant is displaced by new gas plant. Each individual decision will require a choice on location. We should assume that these decision will be driven by private financial benefits.

There are a number of ways in which the revenue earned by generators varies by location under the current frameworks. These include:

- Energy prices – which vary by region, mainly due to transmission constraints between regions;
- Energy volumes – the risk of not being able to run to the desired volumes due to the presence of cheaper generation or transmission constraints;
- Distance – the amount of energy deemed to have been sold at the regional load centre is adjusted for the proportion of energy lost in transit (transmission losses e.g. in the form of heat); and
- Connection costs – some locations might require less transmission works to facilitate connection.

The risk is that, collectively, these signals are too weak – and do not fully reflect the costs that are being imposed by the connecting generator. If this is the case, then generators might locate inefficiently. If large numbers of generators do this, then cost inefficiencies might be high, e.g. as a result of inefficient network investment chasing poor locational decisions by generators. The historic evidence suggests that congestion costs are relatively low in the NEM, but this has the potential to change as a result of CPRS and expanded RET. Assessment of options to address this risk will need to be aware of the costs of provide sharper location signals (e.g. in managing the associated price risks) as well as the benefits.

9. Transformation in energy networks

9.1. Objectives

Energy markets will have stood up well to the task of transforming energy networks if regulated network businesses are responsive to, but do not pre-empt or crowd out private investment in generation (or transmission).

This requires network investment planning to be transparent and predictable – and delivered at efficient cost. This is a significant challenge given the potential size of the investment task. It also requires network businesses to have strong, well-designed financial incentives through the regulatory regime to deliver the maximum network capabilities when it is most valued to the market.

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, e.g. 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. However, CPRS might potentially accelerate this shift from coal to gas – with accelerating implications for energy networks. More importantly, however, is the likely rapid acceleration of wind generation connection application in remote areas of the network pursuant to expanded RET.

Our view is that the current arrangements provide a strong foundation for managing network investment in response to changing patterns of flows across the main interconnected transmission grid. However, the current framework is not well suited to managing large extensions to the network to connect large volumes of remote renewable generation.

9.2. Strengths of the current framework

Economic regulation of transmission

The rules governing how regulated electricity networks are remunerated for the services they provide are robust, transparent and consistent with efficient decision making. There are five facets to this framework:

- Connection services provided (and priced) through bilateral negotiation between the relevant TNSP and the connecting party – with the ability for disputes to be taken to arbitration.

- Revenue allowances for the provision of shared services determined by periodic review by an independent regulator (the AER) applying a framework defined in the market Rules. The allowances are set ex ante, and are required to make appropriate provision for the financing costs of past investment decisions and for forecast capital expenditure requirements. This framework provides strong incentives for cost efficiencies – and minimises the risk of assets being "stranded" as a result of ex post regulatory decisions;

- Regulatory oversight of how prices for using the network are set, consistent with principles defined in the market rules;

- The ability for the regulator to devise complementary incentive scheme to reward good performance and penalise poor performance against specified output measures. Up to 5 per cent of revenue can be put "at risk" under these incentive schemes; and

- Evidence-based and consultative processes for reviewing and, where necessary, amending key regulatory parameters, including the appropriate rate of return allowed on regulated investments.

The AEMC undertook a comprehensive review of these arrangements in 2006, at the direction of the MCE. The introduction of a CPRS and expanded RET is likely to result in larger costs being processed through the framework. The broad framework for economic regulation described above appear well placed to handle this.

Transmission investment planning framework

While effective economic regulation has an important role to play, it is also critically important that regulated network businesses are accountable for the investment decisions they make. Regulation of the investment planning process is a means of delivering this accountability. This is particularly important in Victoria, where the organisation with responsibility for planning and procuring transmission investment (VenCorp) is not-for-profit, such that its behaviour is less likely to be influenced by financial incentives.

The current framework provides for two routes of accountability and consultation for how transmission investment is planned. First, each network business is required under the market rules to publish an Annual Planning Report each year, reporting on investment undertaken and highlighting future investment needs in its region. Second, for individual issues that might require significant investment the business is required to apply the Regulatory Test. This is a process of assessment and consultation on the specific network constraint or reliability issue to be addressed, and options to address them. The purpose of the Test is to provide an opportunity for stakeholders to scrutinise the planned expenditure, to highlight alternatives and to identify the most cost effective responses.

An area of potential weakness in the framework lies in the regional basis for transmission planning, and the consistency of outcomes with objectives for the national market. This is a legitimate concern, and has been raised a number of times by policy makers. The most recent example being the Energy Reform Implementation Group (ERIG) report to the Council Of Australian Governments (COAG) in 2007.[8] The ERIG report gave rise to the decision by COAG to establish a national transmission planning capacity within the proposed Australian Energy Market Operator.

The confluence of regional transmission planning and national policy goals raises heightened concerns in the context of the implementation of a CPRS and expanded RET given the potential for generation to become more concentrated geographically as a result of the RET. Other things being equal, this would tend to increase the extent to which electricity was traded across regional boundaries.

However, within the paradigm of regional investment planning, there are five specific elements of the current framework which address (or propose to address) this potential weakness:

- The ability of the AEMC to direct an individual TNSP to undertake a Regulatory Test if it considers that a material network issue is being overlooked. This is the Last Resort Planning Power (LRPP);

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[8] ERIG, Energy Reform – the way forward for Australia, January 2007.

- The proposed reform of the Regulatory Test to expand the range of costs and benefits that have to be routinely assessed. This addresses the risk that regional transmission businesses place focus unduly on regional reliability benefits at the expense of wider benefits to the market in formulating investment plans;

- The creation of a National Transmission Planner (NTP) in July 2009 as one of the function of the market operator. The NTP will publish a plan each year on optimal planning strategies under a range of long-term development scenarios. TNSPs will be obliged to have regard to this information in forming their own investment plans;

- The proposed introduction of a consistent national framework for setting planning standards for transmission in each jurisdiction. This will increase transparency and predictability for market participants, and reduce information asymmetries for the regulator in determining appropriate revenues for each; and

- The development of more robust ways of recovering the costs of transmission investment from a wider pool of network users, i.e. across regional boundaries. This is the so-called "inter-regional TUoS" question.

Collectively, these features and proposals put the market in a relatively strong position to ensure that network investment is planned and delivered efficiently in support of the transformations in behaviour driven by CPRS and expanded RET. There is, however, the need to convert proposals into implemented reforms in a number of areas.

9.3. Risks within the current framework

Connecting remote renewables

The key stress point for the existing framework for network regulation relates to the large-scale connection of remote renewables. Specifically, the ability of TNSPs to process efficiently the expected large numbers of connection applications (i.e. due to large investment in wind farms).

Each connecting party must negotiate its connection individually with the TNSP. Connection information is treated as confidential, thereby preventing TNSPs from discussing one connecting party's information with any other prospective connecting parties.[9] This creates incentives for generation plant to locate as close as is feasible to the existing network and for connection assets to be sized to accommodate only the individual generator's output. These limiting factors prevent TNSPs from considering more efficient connection investment options. For example, it may be most efficient for a TNSP to build a single large network asset to connect multiple parties rather than several individual assets.

TNSPs also face difficulties when determining what size connection asset to build in areas where additional new remote generation is likely but is not ready at the time of

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[9] NER clause 5.3.8 states that data and information provided under rule 5.3 is confidential information and must be used in good faith and not disclosed to a third party, unless otherwise determined in the NER.

the first connection application. Building the optimal extensions to accommodate future connections requires someone, such as the TNSP, connecting parties, merchant investors or the government, to take the risk that the future generation may not materialise. Currently, management of this risk is allocated to the "first mover" generator. Arguably, they are poorly placed to efficiently manage this risk, given the private commercial incentives. TNSPs are reluctant to take on this risk because of the risk of "stranding" if the anticipated future connections do not materialise. Consumers bear no risk currently – but will potentially bear significant costs if the framework results in cost inefficiencies and delays to new generation connections.

There are more practical, administrative risks. Stakeholders agreed that TNSPs will find it difficult to process the high volume of expected connection applications. Recent estimates indicate that there are approximately 180 existing and prospective future wind farms.[10] On average, TNSPs may be expected to handle around ten additional connection applications each year; they currently receive around three a year. Much of the new generation investment could be clustered in remote areas such as north-west Tasmania, the Eyre Peninsular in South Australia, the geothermal zones in South Australia and the western areas of New South Wales and Queensland, where solar energy is abundant. This implies that the administrative burden may not be distributed evenly across TNSPs.

For these reasons, we have highlighted the need to consider options for change. The options we have identified for consultation range from relatively minor administrative changes to more wide-ranging reforms. At the incremental end of the spectrum are options to create connection application "windows" for areas of anticipated high volumes of connection activity. This might better aggregate the information available to TNSPs, and improve the changes of co-ordinated investment planning.

At the more fundamental end of the spectrum are models which provide for changes to the ways in which risk is allocated. Presently, all connection costs are borne by the connecting generators – with the implication being that the costs are recovered through generator revenues. We are considering alternative models which seek to retain cost-reflective connection charges on generators, while also allowing for appropriate "over-sizing" of the network extension to allow for future connection activity in the same area. This is likely to involve consumers bearing some additional risk compared to the current arrangements, related to the risk of anticipated future volumes of new connections not being realised. The policy question is whether this risk is more or less attractive than the risk under the existing arrangements of multiple bilaterally-negotiated connections being unnecessarily costly (or time-consuming) in aggregate.

[10] Carbon Market Economics, The $60bn question, August 2008. Available: http://www.carbonmarkets.com.au/text/080820%20explanation%20of%2060bn%20calculation.pdf.

10. Transformation in consumption

10.1. Objectives

Energy markets will have stood up well to the task of transforming how we consume electricity if individuals and businesses are empowered to make informed choices based on a full understand of costs and benefits of different patterns of consumption.

This requires electricity tariffs which accurately reflect the efficient costs of supply. It also requires the removal of technological and commercial barriers to consumers more actively participating in energy markets. There are many routes for participation to occur, from the terms of retail contracts through to tailored contracts for demand-side response with network businesses (or NEMMCO).

10.2. Strengths of the current framework

Prices

We have a sophisticated set of market arrangements that seek to promote the supply of electricity at efficient cost. This covers competitive trading of wholesale energy, and the regulation of how networks are developed and paid for. Given the relative importance of network and wholesale energy costs in the composition of the average bill this provides a solid basis for ensuring that prices to consumers are based on the right underlying costs.

How those costs are translated into prices to end consumers depend on the operation of the retail market. In this regard also we would appear to be in good shape. The AEMC has undertaken detailed reviews of the effectiveness of retail competition in Victoria and South Australia, and has reported our findings to the relevant jurisdiction and the MCE. We completed the review of Victoria in 2007, and completed the review of South Australia in 2008. In undertaking these assessments, we analysed the markets against the following criteria:

- the existence of independent rivalry within the market;
- the 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.

In both cases, we concluded that there was effective competition, and that consequently price regulation should be removed. Victoria has since legislated to remove price regulation. Our findings on South Australia were submitted at the end of 2008 and are presently under consideration by the South Australian government.

Small customer retail competition is less developed in a number of other participating states and territories due to the differences in the timing of the extension of competition and customer choice to the household and small business sectors. However, the reviews conducted to date provide strong evidence, based on detailed analysis of how retail markets are operating in practice, that our market frameworks are capable of supporting effective competitive. Consequently, we should be reasonably confident that prices set through the process of competition between retailers should over time reflect the efficient costs of supplying electricity.

Demand-side participation

There are also mechanisms for larger individual consumers to participate more actively in the market directly or via contracts with retailers or network businesses. While the volume of activity in this regard is less transparent than traded volumes in the spot and contract markets, there is evidence of some users taking up these opportunities. Clearly it a choice for an individual consumer as to whether it is worthwhile consuming or not at any given time. It also requires network businesses to be aware of such opportunities, and to have financial incentives which reward contracting for such services if it represents the efficient course of action.

These arrangements might involve agreements to curtail load in certain circumstances, as a means of retailers managing risk at times of very high market prices. An extension of this type of arrangement is for the demand-side response to be aggregated and packaged as a cap contract, similar to a peaking generator. We understand that market participants are exploring these options actively. The CPRS should stimulate this activity by increasing the costs of supply-side (generation) solution compared to demand-side solutions.

10.3. Risks within the current framework

The current arrangements for jurisdictional price regulation are unlikely to promote and support the desired market outcome. There is likely to be a large cost increase for retailers due to the pricing of carbon emissions and the requirement to obtain and surrender RECs. The current regulatory arrangements do not appear sufficiently flexible to enable retailers to manage these cost increases. In addition, the jurisdictional "Retailer of Last Resort" (RoLR) arrangements for managing the consequences of a retailer failure (which is more likely if efficient costs cannot be recovered) are generally recognised as being underdeveloped and inadequate to manage effectively a distressed retailer exit from the market.

Pressures on retailer costs

The CPRS and expanded RET are likely to increase energy retailer costs in a number of ways including: wholesale energy costs, network charges, market operating costs, hardship policy costs and unpaid bills, and direct retailer costs from climate change policies, like carbon permits and RECs. Increases in wholesale energy costs are likely to be the dominant contribution to cost increases.

Wholesale electricity and gas prices are both forecast to increase. There is no consensus on whether electricity price volatility will increase, though there is consensus that gas demand is likely to become more variable. Carbon price risk, which will reveal itself in wholesale energy costs, may also be a contributing factor to price volatility.

Increases in price and price volatility will correspondingly increase prudential and credit support requirements for NEM retailers[11] and gas retailers participating in the Victorian balancing market. The prudential costs for NEM retailers are likely to be substantial. This is occurring in a wider context of tighter credit markets, which other things being equal, increases the cost of providing prudential support. The short-term availability, as opposed to price, of credit support as a result of the credit crunch might also be a factor contributing to the risk of retailer financial distress. This may disproportionately affect smaller retailers, and retailers without a generation portfolio.

Inflexibility in price regulation

Each Australian jurisdiction regulates retail prices differently. This involves differences in the timing of periodic review, differences in the treatment of cost changes within period, and differences in the methodologies applied.

Where the statutory frameworks governing price regulation have provided for "pass-throughs" or "re-opener" events to manage new or increased costs resulting from "green" government policies, there is uncertainty as to whether these are sufficient to account for the cost increases and whether the decision making on these matters would be sufficiently timely. For example, retail price determinations with pass-through provisions can pick up direct and measurable costs, such as the cost of purchasing RECs for electricity retailers or carbon permits for gas retailers. However, accounting for changes to wholesale energy costs and associated hedging costs are much more difficult to manage under the existing arrangements. This is of particular importance as the wholesale energy cost is a major component in a regulated tariff, which in turn impacts on the cost of financing greater prudential coverage as wholesale prices increase.

The costs of inflexibility may be high. In the short term, non-cost reflective pricing can distort competition in retail markets. Retailers may shift costs between classes of customers or, at the extreme, may find it more profitable to lose customers than to continue to provide energy at non-cost reflective prices. Previously competitive retailers may also find themselves in unnecessary financial distress because of rising wholesale energy costs and prudential requirements which they are unable to fully recover under the regulated tariffs. In the longer term, inflexibility can affect investment, give the role of retailers in underwriting (or undertaking) investment in new generation plant. If there is uncertainty about recovering costs in the future then the appetite of retailers to forward contract may decline, which may impact on the form, timing and cost of investment.

The existing levels of flexibility in the regulatory arrangements therefore represent a significant risk for retailers given the large forecast cost increases related to the CPRS and expanded RET.

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[11] NEMMCO, "Australia's National Electricity Market – Trading Arrangements in the NEM", Executive Briefing, 2004, p.16. Available http://www.nemmco.com.au/about/000-0178.pdf.

Handling retailer failure

Large cost changes and inflexible price regulation heighten the risk of retailer failure. The consequences of such an events are potentially compounded by weaknesses in the jurisdictional RoLR arrangements for handling retailer failure. These are the processes that allocate customers to an alternative retailer and provide for the associated costs to be recovered.

The arrangements have not been tested against the failure of a retailer operating in several jurisdictions or a multi-fuel provider, nor against the external administration provisions of chapter 5 of the Corporations Act 2001 (Cth). The only RoLR event in Australia to date was a small company with electricity customers predominantly in a single jurisdiction; it was not insolvent and did not enter administration.

Barriers to demand-side participation

While there are various routes for demand-side participation in the market, the volumes of such participation are uncertain – and potentially inefficiently low. The AEMC has been reviewing the potential barriers to efficient demand-side participation, and we will be publishing our draft findings shortly.

One significant practical barrier is metering technology, and the inability of most metering to support more sophisticated "time-of-use" tariffs and other innovations requiring two-way communication between a user and a retailer or network business. The mass installation of smart meters will facilitate more opportunities for innovation. The MCE has been reviewing its policy in respect of smart metering roll-out, and Victoria has advanced plans for its distribution businesses to install a new fleet of meters within the next five years.

Information for consumers and the consumer protection framework

There are many pressures, both policy and commercial, to transform the way in which individuals, communities and businesses consume electricity. This puts significant weight on the ability of consumers to access the information they need to make informed choices.

There is a risk that consumers (or specific groups of consumers) are not sufficiently well-informed, and that this results in change imposing costs rather than delivering benefits. This may put greater weight on the framework for customer protection. We note that the MCE currently has a work program to develop a national retail framework, and this framework will need to be fit-for-purpose in safeguarding the interests of customers in a period of rapid change.

11. Concluding remarks

The theme of this paper is the ongoing reform of Australia's energy markets, and how this will be impacted by policy initiatives relating to climate change. The AEMC is in the privileged yet challenging position of examining this question in detail in order to advise State and Federal governments.

It could be argued that our energy markets have already been transformed beyond recognition over the past fifteen years as a result of competition reforms. The evidence on performance over this period is encouraging. We should not lose sight of this. However, we should also recognise that introducing a price for carbon and setting ambitious targets for renewable generation capacity will trigger a further transformation in our energy markets over the next fifteen years. This will affect generators, networks and consumers.

It is timely and important for Ministers to ask whether the current frameworks for energy markets can deliver this transformation in a way that maximises benefits and minimises the risk of disruption. Our initial findings are that existing frameworks have much to commend them, and appear capable of handling many of the challenges that a CPRS and expanded RET might bring. However, there are specific areas that may require change – and we will present our findings in this regard to Ministers in September.