AEMC

Review of Energy Market Frameworks in light of Climate Change Policies

1st Interim Report

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About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy markets. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market and elements of the natural gas markets. It is an independent, national body. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council on Energy as requested, or on AEMC initiative.

Foreword

Australia's energy markets are entering a profound and potentially rapid period of change. The Australian Government is introducing significant new policies to address the risks of future climate change that will directly affect behaviour and investment in gas and electricity markets. This will alter the structure of our energy sector over time as we move towards less carbon-intensive forms of electricity generation, and see active responses by electricity and gas consumers seeking to play a role in reducing carbon emissions. The policy environment is dynamic, with the recently published White Paper on the Carbon Pollution Reduction Scheme (CPRS) being the latest step in that process, with further announcements planned for 2009 on an expanded national Renewable Energy Target (expanded RET).

In this context, we have been asked by the Ministerial Council on Energy (MCE) to review the resilience of existing energy market frameworks in this period of change. This will allow any required changes to be made before the new policies are implemented. Our reference point for this assessment is the statutory objectives for our electricity and gas markets to deliver safe, secure, reliable and efficient supplies in the long term interests of consumers.

Energy markets in Australia have been transformed over the past fifteen years, with the creation of new market structures and the growth of competition. This is a strong starting position. Consistent with this, our analysis indicates that existing frameworks are broadly resilient to the changes flowing from the implementation of the CPRS, as set out in the White Paper. The expanded RET represents a greater challenge, in particular on the framework for extending networks to remote areas.

We will be providing our final advice to the MCE in September 2009. The consultation document we are publishing today is an important milestone in this process. In such a dynamic environment, stakeholder engagement will be vitally important in enabling the Australian Energy Market Commission (AEMC) to provide the MCE with robust advice. We look forward to receiving your views on this 1st Interim Report.

John Tamblyn
Chairman, Australian Energy Market Commission

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Executive Summary

The AEMC

The AEMC is an independent, national body with responsibility for Rule making, market development and policy advice concerning both the National Electricity Market (NEM) and elements of natural gas markets. This includes our role to provide advice on energy market issues when requested by the MCE. Our vision is to promote efficient, reliable and competitive energy markets in the interests of all Australians.

This Review

The MCE has asked the AEMC to review whether the existing rules and regulations governing behaviour in energy markets are consistent with promoting efficient, reliable, safe and secure supplies in the long term, given the changes in market behaviour from the CPRS and expanded RET. It is, in effect, a test of whether energy market frameworks are resilient to change.

The CPRS has the effect of placing a price on carbon emissions. This will particularly affect the energy sector, as it is a major emitter of carbon with a large proportion of our electricity produced by burning coal. The expanded RET provides financial incentives to build renewable generation capacity, e.g. wind farms. The introduction of these policies will inevitably lead to changes in behaviour and the entry of new participants into Australia's energy markets. The policies will affect both gas and electricity markets across all jurisdictions.

Where we identify a risk that energy market frameworks might not promote the desired outcomes of energy markets, then we are to assess the options for change. Where we establish that we are able to reduce or remove such risks by amending energy market frameworks, then we are to provide the MCE with a detailed plan for implementing the recommended changes.

This 1st Interim Report

This 1st Interim Report is a significant milestone in the process of developing our advice to the MCE. Its purpose is to identify the "stress points" in the energy market frameworks that require further attention. This will be the focus of our 2nd Interim Report in June 2009, that will assess and provide the options for change to energy market frameworks, where appropriate, to address these "stress points".

It is important to note that our starting position is the energy market frameworks as they exist today plus a number of important reforms that are well developed. These include:

- the establishment of the Australian Energy Market Operator (AEMO) – including its role as National Transmission Planner (NTP) for electricity; and

- the process of considering, and where appropriate implementing, the recommendations from the MCE on the Congestion Management Review (CMR) and Comprehensive Reliability Review (CRR), including the recommended increase of the market price cap to $12 500 per MWh.

We have identified the stress points through analysis of the current energy market frameworks, and analysis of the range of potential scenarios for change in market behaviour resulting from the CPRS and from the expanded RET. We have focused on demanding but credible scenarios from the perspective of each issue examined, drawing on the available evidence.

On 15 December 2008, the Australian Government released its White Paper on the CPRS. This provides new information that will help us further refine the scenarios that should be used to test resilience of the energy market frameworks. However, our initial assessment is that the new information contained in the White Paper does not materially affect the findings set out in this 1st Interim Report.

Key findings

Desired outcomes

There are a number of differnt facets to how we want energy markets to operate, which the frameworks should promote:

- **Reliability:** to deliver investment in different forms of new generation capacity at the right time and location, and at efficient cost. This requires efficient trade-offs between building new generation capacity, and avoiding the need for new capacity by reducing peak demand.

- **System operation:** to allow networks to be operated safely and securely keeping voltage and frequency within the desired tolerances. Where system operators intervene in markets, those interventions should be transparent, effective and not to distort the market.

- **Networks:** to support the market by providing incentives that promote investments to connect new network users and to handle changing patterns of network use that are planned effectively and delivered at efficient cost. The frameworks should also appropriately allocate the costs and risks associated with network investment.

- **Retailing:** to promote effective competition between retailers, and to protect consumers in respect of the prices they pay through regulation where effective competition is not present. Where necessary, regulation should be flexible and not stifle competition.

Resilience of existing frameworks to the CPRS

We have assessed whether existing energy market frameworks are capable of delivering these desired outcomes in the presence of the CPRS, and the behavioural changes that the CPRS may drive in energy markets. The key impact of the CPRS will be increased costs for carbon-intensive generation. This will potentially affect how existing generators operate, and change the economics of new investment in favour of lower-carbon (e.g. gas) and zero carbon (i.e. wind) technologies. It will also increase prices in wholesale markets, and related contract markets.

If the CPRS results, over time, in increased use of existing gas-fired generation and significant investment in new gas-fired generation, then there will be a large increase in the volume of gas and pipeline capacity being contracted for and traded through existing gas markets.

For the CPRS, we have reached the following preliminary conclusions:

- **Wholesale markets and investment:**

  The arrangements governing how wholesale electricity and gas are traded appear capable, without fundamental change, of promoting efficient, reliable and secure energy supplies in the context of the CPRS. In different ways, the NEM and Wholesale Electricity Market in Western Australia (WEM) provide detailed signals as to the required size, location and form of new generation capacity. The CPRS does not obviously detract from this.

  A key element in the NEM is the role of financial contracts, and in particular contracts which insure against high price events ("caps"), in signalling the need for new capacity. As long as regulation does not stifle the ability of this process to work, e.g. by setting the maximum market price too low, then the frameworks appear robust. In the WEM, the signal for new capacity is delivered more explicitly through the operation of a capacity mechanism.

  In respect of gas markets, while traded volumes might well increase substantially, the existing frameworks based on bilateral trading and complemented by the new Bulletin Board (BB) and proposed Short-Term Trading Market (STTM) appear capable of facilitating efficient gas market trading and the required investment in new capacity.

- **Short-term management of reliability:**

  There is a tight generation capacity margin in some NEM regions in the period to 2010-15, and there are risks of some capacity being retired. In part this probably reflects the timing of investment being affected by policy uncertainty about the CPRS. In this regard, there is a potential for more expansive intervention by the system operator in the short term.

  The NEM framework has a number of settings and mechanisms to assist the management of reliability in the short, medium and long term. These have recently been reviewed by the AEMC Reliability Panel, and a number of modifications have been made or are being progressed progressed (for example, the level of Value of Lost Load (VoLL)).

However, we consider that the existing framework may need to be modified further to manage more effectively the unlikely but credible contingency of an actual or anticipated large reserve shortfall in a region. It might be appropriate for additional mechanisms to be temporary. This does not appear to be an issue in Western Australia or the Northern Territory.

- **Retailing:**

  There are, however, significant risks associated with the elements of the regime for energy retail regulation. These risks are pre-existing, but are likely to materialise and increase as a result of implementing the CPRS. The CPRS introduces a new, and potentially uncertain, cost into the supply chain for wholesale electricity. In addition, higher wholesale costs also mean higher prudential costs for retailers.

  We do not consider that the current retail price regulation arrangements are sufficiently flexible to be able to cope with these potentially large and rapid changes in retailer costs. We also consider that the regulatory contingency plans for handling the financial failure of a retailer (the "Retailer of Last Resort" (RoLR) arrangements) are not adequate.

  While there are a number of processes underway to investigate potential changes to address these issues, we consider that there is a risk if these reforms are not progressed and implemented in line with the introduction of the CPRS and expanded RET.

Resilience of existing frameworks to the expanded RET

- **Transmission investment for new connections:**

  The expanded RET will stimulate investment in renewables. This is likely to be in the form of wind generation capacity in the medium term. The new forms of generation are likely to be clustered in certain geographic areas that are remote from consumers and the existing transmission network. We consider that the existing model of bilateral negotiation for new connections will not cope efficiently with multiple connection applications to the same area nor will it be likely to manage efficiently the large expected volume of new connection applications. It is likely that this may result in unnecessary costs and delays.

- **Managing network congestion:**

  Under some scenarios, the expanded RET stimulates increased network congestion within and between regions. This is particularly due to the new and different generation mix (i.e. renewables and their location decisions). Whilst there is some evidence, we are of the view that further work is required to establish the potential materiality of future network congestion resulting from the expanded RET. We consider, however, it is prudent to continue examining whether the current signals for "self-management" of network congestion are clear enough and strong enough in such an environment. This is a particularly pressing issue in Western Australia, including in relation to the consequential actions required by or on behalf of the system operator.

How stakeholders can be involved in the next stages of the Review

We are now inviting submissions on this 1st Interim Report by 20 February 2009. We are particularly interested in your views and evidence in support of the following:

- whether we are focusing on the right issues; and
- what particular options for change should we consider.

Further information on the practicalities of making a submission to the AEMC can be found on our website.

We will also be hosting a public forum before we publish our 2nd Interim Report. The date for the public forum has not yet been set, but we expect to hold it in April 2009, when we will be in a position to present our initial thoughts on options for change.

1. The Review

1.1 Background

The AEMC is undertaking a Review of Energy Market Frameworks in light of Climate Change Policies, as directed by the MCE on 13 June 2008.[1] The Review is to determine whether the existing energy market frameworks for the electricity and gas markets require amendment to accommodate the introduction of the CPRS and the expanded RET.

The Review is to:

- examine the potential impacts of the CPRS and expanded RET on both the electricity and gas markets across all jurisdictions;

- determine what adjustments may be necessary within the existing energy market frameworks, having regard to the National Electricity Objective and National Gas Objective – to deliver efficient, safe, secure and reliable energy supplies in the long term interests of consumers; and

- provide detailed advice to the MCE on the implementation of any amendments required.

The MCE has indicated that the Review is not to assess the merits of the policy design of the CPRS or expanded RET. The review of these schemes is being undertaken through other government policy processes.

Energy Market Frameworks

Energy market frameworks include the Laws, Regulations and Rules governing the national electricity and gas markets, and other laws and regulatory instruments influencing how participants in energy markets behave, including state-based instruments. An overview of the governance and institutional arrangements for the energy market can be found at www.mce.gov.au.

Over recent years, there have been a range of reforms progressed which have relevance to this Review. The changes, where supported by the MCE, are considered part of the existing energy market frameworks for the purposes of this Review.[2]

1 The MCE Terms of Reference for the Review can be found at www.aemc.gov.au.

2 The relevant reviews are listed at the end of section 1.1. The relevant Rule changes include: The National Electricity Amendment (Central Dispatch and Integration of Wind and Other Intermittent Generation) Rule 2008 No. 2 ("Semi-Dispatch" Rule).

Key assumptions

As indicated in the Scoping Paper,[3] this Review is being undertaken in parallel with the Australian Government's program for designing the CPRS and the expanded RET. Therefore, the Review is based on assumptions about the precise final form of the policies, the best available public information, and has also been tested with the Review's stakeholder Advisory Committee. The Australian Government's White Paper, released on 15 December 2008, provides clarity on the particulars of the CPRS, including the trajectories for achieving carbon reductions. We have re-examined the issues based on the new information, however a more thorough analysis of this information will be undertaken in the next phase to inform our 2nd Interim Report due for release in June 2009.

Interactions with other work by the AEMC

Many of the issues being considered under the Review impact, or at least intersect, with current work being undertaken by the AEMC and other reforms being progressed by the MCE. The MCE has requested that the AEMC take these into account for the Review.

Of specific relevance to this Review, is the AEMC Review of Demand Side Participation (DSP) in the NEM and the Total Environment Centre Inc (TEC) demand management Rule Change proposal. These projects are important to consider in parallel to this Review because the CPRS will impact on the potential costs and benefits of demand-side solutions in the market. For this reason, we have aligned the timetable of these projects to that of the Review.

As noted, there are a number of other Reviews that have been completed or are underway. The objectives of these Reviews, and outcomes where appropriate, have been taken into account in determining the materiality of the issues. The outcomes of the completed Reviews will address many of the issues highlighted in the Review and strengthen the capability of the existing frameworks to accommodate the introduction of the CPRS and, to a lesser extent, the expanded RET.

3 AEMC, *Review of Energy Market Frameworks in light of Climate Change policies: Scoping Paper,* October 2008.

The particular Reviews include:

- the AEMC Review of the NTP, including the revised Regulatory Test (known as the Regulatory Investment Test for Transmission (RIT–T));
- the AEMC Reviews of the Effectiveness of Competition in Electricity and Gas Retail Markets – Victoria and South Australia;
- the AEMC Congestion Management Review (CMR) and;
- the AEMC Reliability Panel's CRR, including the Rule Change proposal from the AEMC Reliability Panel relating to reviewing the Value of Lost Load and market floor price.

More information on AEMC Reviews and Rule changes can be found at www.aemc.gov.au.

1.2 Progress to date

Scoping Paper

In October 2008, we published our Scoping Paper for the Review. This paper identified the broad set of issues where, as a result of the new policies, there appeared to be a potential risk that continuing with existing market frameworks might result in behaviour, which is inconsistent with the relevant energy market objectives, such as the safe, secure, reliable and efficient supplies of electricity and gas. It also provided an overview of the new policies and identified existing energy markets relevant to the Review.

We sought views from stakeholders on:

- whether we had identified the scope of the issues appropriately;
- what issues are material; and
- what evidence is relevant to assessing the materiality of each issue.

This Report

This Report sets out the issues as outlined in the Scoping Paper that are considered appropriate to take forward into the next stage of the Review, together with our supporting reasoning, including comments made in submissions to the Scoping Paper. Our framework for prioritising the issues is provided in chapter 2. In some areas, we also set out some possible mitigation measures, where we consider this appropriate. For each of the issues, we ask a range of questions to get stakeholders' views on whether we are focusing on the appropriate issues and, if not, why. We are also seeking comments on the options for mitigation.

Structure of this Report

This Report is structured into three parts; that is:

- Part A – provides the analysis and conclusions of the issues in the context of the NEM and the natural gas markets of Queensland, New South Wales, Victoria, Tasmania and South Australia;
- Part B – provides the analysis and conclusions of the issues in the context of the Western Australian electricity and gas markets and;
- Part C – provides an analysis and conclusions with respect to the Northern Territory.

In addition to the Report, we are publishing a number of supporting papers. These include supplementary AEMC papers: (1) a survey of the evidence of the implications of climate change policies that has been compiled from various sources of information in the public domain; (2) on the role of the system operator; and (3) on the current arrangements for energy retailing. We are also publishing several consultancy reports commissioned by the AEMC for this Review. These papers have been used to inform the conclusions we draw in this Report.

1.3 The Review timetable

Document	Purpose	Date
Scoping Paper	To set out and seek views on the range of risks to be considered in the Review, and to seek initial views from stakeholders on possible mitigation measures.	10 October 2008
1st Interim Report	To provide a "short list" of issues that we think are appropriate to focus on, together with our supporting reasoning. We will also provide directional comments on mitigation.	**Submissions due 20 February 2009**
Public Forum		April 2009
2nd Interim Report	To update 1st Interim Report in light of the White Paper and set out what mitigation measures we intend to recommend and why.	By 30 June 2009
Final Report	To finalise the advice to the MCE on the range of mitigation measures we are recommending and why. We will also provide advice on legal and operational implementation.	30 September 2009

1.4 Stakeholder engagement

During the course of the Review we will continue to engage with our stakeholders. During this first stage, we have undertaken a range of consultations including through our stakeholder Advisory Committee,[4] stakeholder submissions on the Scoping Paper and a series of bilateral discussions. For the next stage of the Review, and as required by the MCE, we will be holding a Public Forum in April 2009. We anticipate the public forum will be an opportunity to discuss the issues which have been highlighted in the 1st interim report and the possible mitigation strategies that may be required. We also envisage that further stakeholder discussions will be required to further develop the preferred mitigation strategies.

How to make a submission

If you would like to make a submission, please send it to: submissions@aemc.gov.au or in hardcopy to:

Australian Energy Market Commission

AEMC Submissions

PO Box A2449

SYDNEY SOUTH NSW 1235

The closing date for submissions is **20 February 2009**. Submissions sent via e-mail/mail should reference the following: Company/Organisation name, 1st Interim Report, December 2008 - Reference EMO 0001.

If your submission contains results of quantitative analysis, we request that you cite sources and provide explanations or references for how the results were derived. This will enable the AEMC to give due weight to the analysis. We recognise that this material might contain information that is confidential in nature. All information, including confidential information, will be treated in accordance with the AEMC's submissions guidelines which can be viewed at www.aemc.gov.au.

4 The Review stakeholder Advisory Committee comprises energy market operators and planners, regulators, industry and energy end-user groups. The full list of Advisory Committee members and outcomes of meetings can be found at www.aemc.gov.au.

2. Approach: prioritising the issues

This chapter describes the framework adopted by the AEMC to prioritise and determine those issues that warrant further consideration and possible mitigation measures for the next stage of the Review.

2.1 Overarching objectives

Promoting efficiency

The Review is seeking to test the ability of energy market frameworks to continue to promote specific objectives. These objectives are set out in the:

- National Electricity Law (NEL) *(National Electricty (South Australia) Act 1996 (SA))*;
- National Gas Law (NGL) *(National Gas (South Australia) Act 2008 (SA))*;[5]
- *Electricity Industry Act 2004 (WA);*
- *Electricity Reform Act (NT).*

These objectives are outlined below.

Under section 7 of the NEL, the National Electricity Objective (NEO), is:

> *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, safetly, reliability, and security of supply of electricity; and*
>
> *(b) the reliability, safety and security of the national electricity system.*

Section 23 of the NGL, the National Gas Objective (NGO), states that:

> *The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas.*

Section 122(2) of the Electricity Industry Act (WA) states that the objectives of the market are:

> *(a) to promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system;*
>
> *(b) to encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors;*

5 All the Australian jurisdictions have adopted the NGL with the exception of Western Australia that is still operating under the National Third Party Access Code for Natural Gas Pipelines Systems. Western Australia is, however, in the process of adopting the NGL.

(c) to avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as those that make use of renewable resources or that reduce overall greenhouse gas emissions;

(d) to minimise the long-term cost of electricity supplied to customers from the South West interconnected system; and

(e) to encourage the taking of measures to manage the amount of electricity used and when it is used.

Section 3 of the Electricity Reform Act (NT) states that:

The objects of this Act are –

(a) to promote efficiency and competition in the electricity supply industry;

(b) to promote the safe and efficient generation, transmission, distribution and selling of electricity;

(c) to establish and enforce proper standards of safety, reliability and quality in the electricity supply industry;

(d) to establish and enforce proper safety and technical standards for electrical installations;

(e) to facilitate the maintenance of a financially viable electricity supply industry; and

(f) to protect the interests of consumers of electricity.

We interpret these objectives as predominantly relating to economic efficiency. This includes both how efficiently Australians use resources today to meet the immediate electricity and gas needs, and how efficiently new resources are committed over time (e.g. through investment) to meet the future needs of the energy markets.

Prioritising issues

The Scoping Paper identified a broad range of issues. In this 1st Interim Report we identify a smaller set of issues that we intend to analyse further with a view to identifying options for change. We have chosen this set of issues having regard to whether:

- the issue or its consequences are attributable to the CPRS or expanded RET;
- changes to energy market frameworks have the potential to make a difference;
- if the issue materialises, there will be significant economic costs; and
- there is a high probability that the issue will materialise (under a demanding but credible scenario).

We have also sought to prioritise issues which would appear potentially difficult to address through the existing routine Rule change governance mechanisms. Specifically, we have sought to focus on issues which might:

- require significant or complex changes to energy market frameworks; or
- create additional risk if they are not addressed quickly.

Our focus has been on issues which require action in the short to medium term. Climate change policies may, over time, lead to major shifts for both supply of energy and demand management. There appears to be a reasonable consensus on the likely immediate impacts up to 2020. The nature of longer term impacts is more speculative. It is not necessary to address these possible long term impacts now and there are benefits from delaying action until the nature of the long term impacts are clearer.

This is likely to result in different types of recommendations in the Final Report. It might, for example, include plans for developing and implementing any changes if deemed necessary, drafting legal text for specific issues, and observations on issues where lower level change appears to have merit.

We consider that this approach is both practical and consistent with good regulatory practice. It focuses efforts and resources on the issues that matter most while respecting the role of open and effective proccesses in developing energy market frameworks over time.

Issues for the Review

Issue 1: Convergence of gas and electricity markets

Issue 2: Generation capacity in the short term

Issue 3: Investing to meet reliability standards with increased use of renewables

Issue 4: System operation and intermittent generation

Issue 5: Connecting new generators to energy networks

Issue 6: Augmenting networks and managing congestion

Issue 7: Retailing

Issue 8: Financing new energy investment

Part A: Issues for the Review – NEM and Gas Markets

Introduction

Part A provides our analysis of the eight issues identified in the Scoping Paper for the National Electricity Market (NEM) and eastern states' gas markets.

The National Electricity Market

The NEM is an energy-only market through which wholesale electricity is traded in the eastern and southern states of Australia. It commenced operation on 13 December 1998. The scope of the NEM is defined by the interconnected transmission network that covers more than 4 000 km and runs from Port Douglas in Queensland to Port Lincoln in South Australia, and across to Tasmania via a sea-bed cable from Victoria. The market consists of five regions which are based on jurisdictional regions: Queensland, New South Wales, Victoria, South Australia and Tasmania.

National Gas Market

Australia's natural gas market is characterised by the eastern interconnected gas network and the separate Northern Territory and Western Australia markets. The eastern interconnected gas network includes: New South Wales, the Australian Capital Territory, Victoria, South Australia, Tasmania and will include Queensland when a pipeline known as the QSN link is complete. This is due to be commissioned in January 2009. Western Australia and the Northern Territory are not connected with other jurisdictions, and thus operate their own separate market schemes.

Issue A1: Convergence of gas and electricity markets

Chapter Summary

This chapter assesses the issue of increased convergence of gas and electricity markets. The CPRS and expanded RET are expected to increase the level of gas-fired generation as there is a move away from carbon intensive fuels such as coal. The interactions and reliance between the gas and electricity markets therefore becomes important. We consider that the existing frameworks are capable to cope with the changes that may result due to the CPRS and expanded RET.

Questions

A1.1 Do you agree that the convergence of gas and electricity markets is not a significant issue in the eastern states and therefore should not be progressed further under this Review? If not, what are your reasons for asking us to reconsidering this position?

What is the desired market outcome?

The desired market outcome is for market arrangements to support competitive and efficient and timely trading and investment in gas and electricity markets across a wide geographical area and for a range of demand profiles.

As demand for gas and electricity grows, the interactions and reliance between the gas and electricity markets also increases. Arrangements that consider how best to co-optimise the desired market outcome in both energy markets become increasingly important. This does not necessarily point to greater convergence in market designs, however. Rather, the arrangements require:

- sufficient flexibility and responsiveness in gas market mechanisms, like bilateral contracting for gas supply, the role of third party access to the gas network and the ability to access storage capacity that can manage greater and more volatile gas demand;
- operational procedures and processes that respond to emergency supply shortfall situations in one energy market to recognise and have regard to the potential consequential effects for the other energy market. For example, the decision to curtail supply to a gas-fired generation plant needs to take into account the impact on the electricity market of a reduction in that gas-fired plant's output; and
- incentives that deliver timely investment in gas production and transportation infrastructure to meet growing gas demand (see Chapter A3).

The CPRS and expanded RET are forecast to increase materially the level of gas-fired generation as there is a move away from carbon intensive fuels such as coal. A high level of fuel switching for electricity generation from coal to gas could increase overall gas demand. An increase in gas-fired generation to back up an increase in renewable generation, such as wind, could also contribute to a more volatile gas demand. Gas-fired generation plant is able to quickly respond to changes in supply conditions and can therefore complement the variability in wind output. This means more variable demand on gas supplies and pipeline infrastructure.

Projected increases in gas-fired generation would require access to greater volumes of gas and transportation capability, possibly at a varying rate than is currently the case. For example, upper bound forecasts suggest consumption of gas for electricity generation in the NEM could rise from 200 PJ to 600 PJ per annum in the next ten years.[6] Another study suggested that under a 20 per cent emissions reduction target an additional requirement of 5 000 MW to 7 000 MW of new gas turbine capacity may be required by 2020.[7]

Will the current energy market frameworks deliver?

Frameworks are robust

The frameworks will continue to support competitive and efficient and timely trading and investment in gas and electricity markets across a wide geographical area and for a range of demand profiles.

This is because:

- the bilateral contracting arrangements, net pool in Victoria and current gas market developments can support trading and investment in light of a greater and more volatile gas demand;
- the differences between the gas and electricity markets are not a problem per se; and
- the AEMO can manage the energy security issue at the interface, so long as it has an explicit objective and obligation to manage this risk.

The reasoning for these conclusions is presented in the following sections.

Is this an issue for further consideration?

Not a material issue

Gas market framework and interactions with the electricity market framework

The bilateral contracting arrangements for both gas supply and access can be relatively sophisticated and appear sufficiently flexible to respond to the changes in gas demand forecast under the CPRS and expanded RET.

6 McLennan Magasanik Associates (MMA) 2008 Initial Market Issues paper, pp.35-36.

7 AEMC 2008 Survey of Evidence, pp.47-50.

The Victorian market and initiatives, such as the STTM (to commence in 2010) and Bulletin Board (BB) (implemented in July 2008), provide and promote a secondary market for short-term trading that complement these contracting arrangements. The STTM and BB improve the information (i.e. short-term (daily) prices) and transparency within the gas market.

Access to gas supply

Outside of Victoria, participants negotiate bilaterally for gas supply. These contracts can be quite sophisticated. To meet a more variable demand profile for instance, there is no reason why participants could not seek greater optionality and flexibility in their future gas contracts. Terms, prices and quantities can vary significantly and are generally confidential, but this can reflect participants negotiating terms that fit best with their requirements.

That being said, more complicated contracts may have higher transaction costs, that could disproportionately affect smaller gas retailers. These players may have limited negotiation capability due to their comparably small capacity requirements.[8]

The introduction of the STTM will provide an additional option for users in Sydney and Adelaide to buy or sell gas on the short-term market and also allow contracted parties to manage short-term supply and demand variations to their daily contracted quantities.[9] Currently, gas balancing occurs under the jurisdictional market rules or bilaterally, with short-term trading available subject to negotiation on contract terms. The STTM may improve the ability to procure gas supply to meet short-term changes in demand profiles.[10] This improves upon the low transparency levels around contract terms, conditions and pricing, and the transparency of gas volume and capacity availability inherent in a principally bilateral-trading market.[11]

Stakeholders considered that gas market structure, when combined with the outstanding long-term gas supply and access contracts, may affect the level of competition for gas supply and pipeline capacity.[12] In its final report and recommendations to Ministers, the Ministerial Council on Mineral and Petroleum Resources (MCMPR/MCE) Joint Working Group (JWG) considered that market structures and operation barriers would be addressed largely by current policies and projects, like the BB, STTM, establishment of the AEMO and the economic and non-economic packages through the NGL and the National Gas Rules (NGR)[13/14].

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8 As noted by the Energy Retailers Association of Australia (ERAA) (p.3), smaller gas retailers may find purchasing or selling gas to balance their positions a more costly exercise in the future than under the current demand profile. The materiality of the issue depends on the ability of small gas retailers to recover these costs, to the extent they are competitive and efficient. This cost recovery question is considered in chapter A7.

9 Energy Networks Association (ENA), p.2; Origin Energy, p.2; Stanwell Corporation, p.3; TRUenergy, p.1.

10 Jemena, p.7.

11 Babcock and Brown Power, pp.8-9; ERAA, p.3; Stanwell Corporation, p.4; Consumer Action Law Centre, p.6.

12 Babcock and Brown Power, p.9; Stanwell Corporation, p.3; TRUenergy, p.2.

13 Joint Working Group on Natural Gas Supply, Final Report of the Joint Working Group, Ministerial Council on Mineral and Petroleum Resources, Ministerial Council on Energy, Volume 1. November 2007, p.20. Available: http://www.doir.wa.gov.au/documents/Volume_1_-_JWG_Final_Report.pdf.

14 MMA, Report to the Joint Working Group on Natural Gas Supply – Natural Gas in Australia, Volume 2, Ministerial Council on Mineral and Petroleum Resources, Ministerial Council on Energy, 16 July 2007, p.75. Available: http://www.doir.wa.gov.au/documents/Volume_2_-_MMA_Report.pdf.

Access to pipeline capacity

Excluding the Victorian Principle Transmission System (PTS), participants can purchase access to pipeline capacity to guarantee transportation of a given volume of gas.[15] Given the negotiations are bilateral, parties can agree on conditions that account for the generation plant's demand pattern, e.g. base-load, mid-merit or peak.

In addition, the new BB can facilitate improved decision-making and gas trading by improving transparency and information sharing. This can assist in managing emergencies and gas system constraints.[16] The BB provides information on physical and available pipeline capacity and demand forecasts covering all major production pipeline systems in the eastern states. Participants may find it easier to trade gas capacity to meet short-term changes in their demand profile.[17] It supplements the existing contractual capacity arrangements, providing a framework and incentives to allocate existing (or invest) in additional capacity efficiently (with firm access rights).[18]

These arrangements have delivered timely investment in new gas production and pipeline infrastructure. In addition, the new Gas Statement of Opportunities (GSOO), which the AEMO is to develop, will help assist existing participants and potential new entrants to identify investment opportunities and manage their positions in the gas market.[19] We consider these arrangements can continue to deliver investment in the necessary gas infrastructure required in light of the change in gas demand under the CPRS and the expanded RET. This issue is discussed in more detail in chapter A3.

The regulatory framework also provides safety nets for negotiating access should privately-owned (uncovered) pipeline owners withhold access in an uncompetitive manner. Participants can apply to the National Competition Council (NCC) to have a pipeline covered (regulated). If the NCC considers that a pipeline should be covered, it makes a recommendation to the relevant Minister, and the Minister makes the decision whether or not the pipeline should be covered. If a pipeline is covered, the pipeline operator must submit an access arrangement, which includes prices and terms and conditions, to the Australian Energy Regulator (AER) for approval. This mitigation mechanism helps promote competition for access to pipeline services on uncovered pipelines.

15 The range of negotiated gas volumes includes: maximum daily quantity (MDQ), maximum hourly quantity (MHQ) and annual contract quantity (ACQ).

16 The Bulletin Board operates in Victoria, South Australia, Tasmania, New South Wales, the Australian Capital Territory and Queensland. Provision has been made for Western Australia and the Northern Territory should they wish to participate at a later date.

17 Jemena, p.7.

18 Australian Pipeline Industry Association (APIA), p.8; ERAA, p.10; Jemena, pp.11-12; VENCorp, p.25; Origin Energy, p.15.

19 http://www.doir.wa.gov.au/documents/Volume_1_-_JWG_Final_Report.pdf

Victorian market

Victoria operates a wholesale gas market and open access to the PTS. The Victorian net pool enables participants to trade outside of their contracted gas positions, setting prices every four hours.[20] Participants do not need to contract for pipeline capacity. As the profile for gas demand changes under the CPRS and expanded RET, the pool provides a market for participants to manage greater variance. However, a few submissions noted that the incentives for private capacity investment in Victoria may be weaker compared to the other eastern states because of the different capacity allocation arrangements.[21]

Energy market convergence

While there were mixed views between stakeholders as to whether there should be greater convergence between the gas and electricity market frameworks, the gas market participants generally commented that greater convergence was not necessary.[22] The Energy Supply Association of Australia (ESAA) and Origin Energy both noted that it was important for NEM price caps to be set at a level that recognised the value of gas but did not create incentives for arbitrage between the two markets.[23]

Very few stakeholders commented specifically on the potential for arbitrage opportunities between the gas and electricity markets. Only the Major Energy Users (MEU) offered an observation that arbitrage activities in New South Wales in July 2007 resulted in a loss of gas supply to major users.[24]

Currently, there does not appear to be any evidence suggesting a high risk of arbitrage opportunities arising from greater interdependence between the gas and electricity markets. The potential issues arising may relate to the reliability and security of supply. Making sure that the transparent pricing signals in the energy markets in times of scarce supply and high demand reflect those economic costs is important. As discussed above, the gas market is moving towards a more transparent pricing regime. Energy market participants may use these signals to make informed decisions about efficiently optimising supply in each market, taking account of their respective contractual obligations in each market.

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20 VENCorp, Guide to the Victorian Gas Wholesale Market, 1 February 2007, p.10. Available: http://www.vencorp.com.au/.

21 ERAA, p.10; TRUenergy, p.16; Origin Energy, p.15.

22 ENA (p.2), APIA (p.7), and Jemena (p.7) did not support greater convergence. The National Generators Forum (NGF) (p.5) and ESAA (p.4) supported greater consistency between the two markets.

23 ESAA, p.4; Origin Energy, p.2.

24 MEU, p.13.

Energy security

Some stakeholders noted as an important issue the risks surrounding energy security (electricity and gas supply).[25] As indicated, we expect the establishment of the AEMO to reduce greatly the potential risks associated with greater reliance on gas-fired generation to meet electricity demand.

The AEMO will only be an improvement on the current arrangements if it has an objective to co-optimise the efficient supply of gas and electricity to consumers. This is a critical issue for consideration of the AEMO board as it prepares to commence its role as energy market operator from 1 July 2009.

Currently, gas-fired generation plant load is normally dropped early when load shedding is required because the loss of large loads can help restore gas system security faster. The Victorian gas market appears to be the only one that must explicitly have regard to the implications for the electricity market when considering gas load shedding.[26] In the other eastern gas jurisdictions, the gas load shedding arrangements for gas-fired generation plant branching off transmission pipelines are governed by confidential bilateral contracts.[27] Having a single body responsible for both gas and electricity market security and reliability may increase the likelihood of considering what impact load shedding in one energy market may have on the other energy market.[28]

The level of communication between the gas and electricity market operators is a key element of this issue. Currently, there appears to be various approaches for the different jurisdictional gas operators. VENCorp, the central gas operator in Victoria, is required to advise the National Electricity Market Management Company (NEMMCO), the NEM market operator, before curtailing supply to gas-fired generation plant.[29] As the interaction and reliance between the gas and electricity markets grow, the level of communication between market operators greatly conditions the materiality of this risk. It is important for the AEMO to establish active communication links between its gas and electricity market operations.

In addition, if investors in gas-fired generation plant consider there is a risk of gas supply interruption, there are a range of risk management options to help mitigate this risk, including gas storage and dual fuel capability. There do not appear to be issues within the existing energy market frameworks that may delay consideration of these risk management options under the CPRS or expanded RET.

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25 Electricity Supply Industry Planning Council of South Australia (ESIPC), p.2; NEMMCO, p.1; Babcock and Brown Power, pp.8-9; Energy Users Association of Australia (EUAA), p.10; Origin Energy, p.2; TRUenergy, p.1; VENCorp, p.21.

26 VENCorp, Gas Load Curtailment and Gas Rationing and Recovery Guidelines, Issue 7.0, March 2003, p.6. Available: www.vencorp.com.au.

27 The load shedding arrangements for gas-fired generation plant that branch off distribution pipelines are governed by relevant distribution access arrangements.

28 Origin Energy, p.2.

29 VENCorp, Gas Load Curtailment and Gas Rationing and Recovery Guidelines, Issue 7.0, March 2003,

Issue A2: Generation capacity in the short-term

Chapter Summary

This chapter considers generation capacity reserve levels and the management of reliability risks in the short term by the system operator. There are tight reserve levels in Victoria and South Australia in the period to 2010-11. There is also some risk of capacity being retired. We consider that the existing framework may need to be supplemented to manage better the unlikely but credible contingency of an actual or anticipated large reserve shortfall in a region. It might be appropriate for additional mechanisms to be implemented, at least temporary.

Questions

A2.2 Do you agree that the ability for NEMMCO to manage actual or anticipated transitory shortfalls of capacity is a significant issue that should be progressed further under this Review?

A2.3 Are additional mechanisms required to complement the Reliability and Emergency Reserve Trader (RERT) and NEMMCO's directions powers, and what characteristics should such mechanisms have?

A2.4 Do you have any views on the detailed design and implementation of additional mechanisms?

What is the desired market outcome?

The desired market outcome is for installed generation capacity to track required levels over time through the decentralised decision-making of individual market participants. This includes decisions on when, where and what type of new generation capacity to build, and when existing generation capacity should be retired. Importantly, it also includes decisions by consumers on how much to consume at peak times (which determines the need for new generation capacity). Where there is a supporting role for system operator intervention, the desired market outcome is for the form of intervention to be effective, efficient and not to distort the ongoing operation of a competitive market.

In the short term, there is limited opportunity to respond quickly to capacity shortfalls by building new generation capacity. This is because of the significant lead times required for development and commissioning of new capacity. This chapter deals specifically with the ability of the current NEM frameworks to manage capacity adequacy given the levels of installed capacity that we currently have, or is in the process of being built.

NEMMCO has an ongoing role to monitor and publish information on the adequacy of reserve levels. This is to inform decisions by market participants, and to inform its own decisions on whether to intervene. In the very short term NEMMCO can intervene by issuing binding operational directions to individual market participants. Further ahead of time, and only if reserve levels are sufficiently low to put at serious risk the required standard for reliability, NEMMCO can contract for additional reserves of capacity to complement the levels of capacity already present in the market. This is the RERT.

The context in which the current frameworks will be tested is as follows. First, capacity reserves in South Australia and Victoria are expected to be at or below minimum reserve levels until at least 2010-11, assuming that all existing generation capacity remains in service, and no new constraints emerge on the operation of existing capacity (e.g. drought-related). Second, the Government announcement of a $3.5 billion assistance package for coal-fired generators as part of the White Paper. This assistance is conditional on existing capacity remaining in service until 2015.

Will the current energy market frameworks deliver?

Potentially require amendments

There is a risk that the current energy market frameworks will not enable NEMMCO to manage an actual or anticipated transitory shortfall of capacity effectively or efficiently. The existing RERT mechanism and directions powers are important parts of the framework. The question is: is there a need for supplementary mechanisms, even if only for a transitional period?

There is a potential need to amend the existing frameworks because:

- in the period up to summer 2010-11, there is a risk of reserve shortfalls in the combined Victorian and South Australian market regions, and in the relevant timescales this risk cannot be mitigated by bringing forward planned investment;

- while the risk of shortfall is significantly reduced as a result of the White Paper proposals on transitional assistance to coal-fired generators, there remains a risk of a further reserve shortfall emerging (e.g. resulting from a technical failure of an existing unit), and the frameworks should be resilient against this contingency; and

- NEMMCO's RERT mechanism is not designed to manage a large or sustained reserve shortfall.

We discuss the reasoning behind these conclusions in the next section.

Is this an issue for further consideration?

This is likely to be a material issue

Existing situation

In the period up to summer 2010-11, NEMMCO's 2008 Statement of Opportunities (SOO) indicates a risk of insufficient generation to meet minimum reserve levels in the combined Victorian and South Australian market regions. The purpose of the SOO is to provide information to the market on opportunities, but it is not a forecast. However, in the short term there are limits to the ability of the market to take up identified opportunities.

Given that lead times for construction of Open Cycle Gas Turbine (OCGT) plant is presently expected to be 22 months[30], there appears to be little likelihood of new scheduled generation appearing in time to mitigate the reserve shortfall identified in the SOO.

There are a number of potential explanations for the current low reserve levels. One potential influence is the deferral by market participants of investment decisions pending clarification of the policy settings for the CPRS and expanded RET. Another potential explanation is past scarcity of plant and labour in light of strong global demand for electricity infrastructure causing project delays.

However, a third explanation is that the market has delivered sufficient capacity, but the minimum reserve levels reported by NEMMCO are an imperfect indicator. In this context, this year NEMMCO identified a shortfall of close to 200 MW for summer 2008-09 in the combined Victorian and South Australian regions, but further studies established that the RERT did not need to be invoked as the probability of unserved energy remained less than 0.002 per cent.

There is also a degree of uncertainty over the actual total level of capacity in the market. The level of potential demand-side response and, to a lesser extent, volumes of unscheduled generation[31] (collectively, embedded technologies), that could potentially be drawn into the market is not routinely reported to NEMMCO. It is not therefore fully reflected in the SOO. While embedded technology options may not be economically viable when there are relatively healthy margins of larger-scale generation, market participants have strong incentives to explore such opportunities when capacity reserves are tight.[32]

In summary, the SOO clearly indicates low reserve levels in the short term in South Australia and Victoria, assuming that all existing capacity remains in the market.[33] This might not necessarily imply an actual shortfall if additional capacity can be drawn in to the market, or is already present but not visible to NEMMCO. It is, however, prudent to allow for the possibility that additional capacity might not be drawn to the market in sufficient volume absent intervention by the system operator.

30 Sinclair Knight Merz (SKM) 2008 New Generation Timelines paper, p.9: SKM refers to "simple cycle gas turbine" (SCGT) which is equivalent to the more commonly used term "open cycle gas turbine" (OCGT).

31 The SOO currently reports on the level of unscheduled generation.

32 The incentive for the market to explore such opportunities arises because of a desire to avoid potential market distortions that could arise if NEMMCO was forced to intervene in the market. Market distortions could prove costly to market participants in the long term if it results in either reduced profitability of existing infrastructure, or confusion of market signals that contribute to a failure to invest in otherwise profitable energy development opportunities. In addition, prices are likely to be high during times of supply scarcity.

33 NEMMCO's SOO assumes existing generation largely continues to be available, with retirement of 600 MW of coal-fired plant flagged for New South Wales and no retirements anywhere else in the NEM for the duration of the SOO outlook. Treasury modelling assumes that changes in Short Run Marginal Cost (SRMC) induced by carbon prices will change the merit order of plant, but does not create a signal for high emission plant to retire.

Potential for early retirement of existing plant

In the prevailing context of relatively low reserve levels in Victoria and South Australia, the withdrawal of any existing generation capacity from those regions would create some difficulties for the management of reserves. Retirement decisions will be driven by expectations of unprofitable operation given the returns required by investors, and a lack of willingness of investors to provide finance (both debt and equity) at those expected returns. A carbon price will increase absolute costs for all fossil-fuel generators, and increase relative costs for the more carbon-intensive fossil-fuel generators. These factors will reduce future profitability of carbon-intensive generators, and therefore the value of the underlying assets.

Prices in spot and contract markets for wholesale electricity are important determinants of profitability. If generation capacity is scarce, then we would expect this to be reflected in higher prices. Other things being equal, higher prices would be expected to deter plant retirement.[34] However, there is a risk that acute and rapid financial distress would trigger unexpected outcomes associated with the availability (as opposed to the price) of finance. Absent additional measures, carbon prices at the levels indicated in the White Paper would substantially impair the value of the most carbon-intensive coal-fired generators. The generators that would be most affected are located in Victoria and South Australia. However, the $3.5 billion (2008-09 dollars) assistance package to coal-fired generators, conditional on capacity remaining in the market, substantially reduces this risk.

There is, however, a "business as usual" risk of technical failure at a unit of an existing plant. If the plant type has only a short term future as a result of the CPRS (e.g. it is brown coal), then investment may not be forthcoming to restore it to service.[35] Further, the current developments in global financial markets may make it difficult to secure finance for any such investment. The risk of technical failure at a unit increases if the unit is being required to vary its output more frequently, rather than run as baseload. A relatively low carbon price in the short term reduces this risk, because it slows down the rate at which the merit order shifts (in favour of less carbon-intensive generators) over time.

In summary, although the risk of capacity being withdrawn due to financial pressures is substantially reduced by the White Paper proposals, there is a residual risk of early retirement of capacity due to technical failure. It is therefore prudent to consider whether the market frameworks are robust to this contingency, given the high probability that any early retirement would result in a material reserve shortfall if it occurred before 2010-11 in either Victoria or South Australia.

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34 Origin Energy, p.6.

35 The incentive to invest in maintenance to return a unit to service following breakdown, will be affected by the conditions surrounding the definition of "in service" that accompany the provision of assistance under the Electricity Sector Adjustment Scheme.

Characteristics of RERT

Intervention by NEMMCO through directions or via the RERT mechanism is an undesirable outcome given the risk that intervention could distort the market. Ideally, market responses in the short term and longer term should be such that interventions are not required.[36] However, it is also prudent to have in place a "safety net", given the potentially very large economic and social costs of unreliable supply. We believe that the existing RERT and directions powers should remain in their current form, as part of the market framework. For example, one of the principles of the RERT is to minimise distortion.[37] The question is whether any additional (potentially temporary) mechanisms are warranted to supplement the RERT and directions powers.

The RERT mechanism was not designed for either large amounts of capacity or relatively frequent use. It can only be invoked up to nine months ahead of time, and it therefore limits the pool of prospective offers of capacity that can be made available within those timeframes. Appropriate capacity might involve (as yet) uncontracted demand-side response, small-scale embedded generation, or bringing forward (where practicable) already planned investment. There would appear to be a limit to how much capacity can be uncovered through this process. There is also a risk of very large costs, if volumes required under the RERT are such that highly uneconomic sources of capacity are being called on (or if there is market power). Such costs are borne by retailers, and are not easily hedged.

Further, in order to assess the volume of DSP available under the current National Electricity Rules (NER), NEMMCO is only able to survey interested parties, where respondents to that survey are not under any formal obligation to identify all their DSP capability. There is, therefore, a risk that the market under-declares the actual volume of demand-side response in expectation of earning substantial profits through the RERT once it is triggered.

In summary, the existing directions and RERT powers are important parts of the regime and should remain in place. But it is prudent to assess whether additional measures are required to enable NEMMCO to manage a situation of large scale reserve shortfall – an unlikely, but credible scenario in Victoria and South Australia.[38]

36 ERAA, p.4; Ergon Energy, p.5; MEU, p.16; TRUenergy. pp.6-7.

37 NER clause 3.20.2(b)(1).

38 Babcock & Brown Power, p.12; EUAA, p.12.

Issue A3: Investing to meet reliability standards with increased use of renewables

Chapter Summary

This chapter considers the ability of the existing frameworks to support the efficient and timely delivery of new generation capacity, including to complement potentially large volumes of new wind generation capacity. Wind generation delivers energy, but can only be relied on a very limited degree to deliver energy at times of peak demand. We consider that the framework of the energy-only market is robust, and provides appropriate signals for the timing, form and location of new investment. This is supported by market participants, and by quantitative modelling undertaken by the AEMC Reliability Panel. It is, however, critically important that the processes for reviewing and amending market settings (e.g. the maximum market prices) are robust.

Questions

A3.1 Do you agree that the existing framework based on an energy-only market design with supporting financial contracting is capable of delivering efficient and timely new investment, including fast response capacity to manage fluctuations in outputs resulting from larger volumes of intermittent wind generation? If not, what are your reasons for reconsidering this position?

A3.2 Do you agree that the processes supporting the ongoing maintenance of this framework in respect of review and periodic amendment to the market settings, including the maximum market price, are robust? If not, what are your reasons for reconsidering this position?

What is the desired market outcome?

The desired market outcome is for installed capacity to track required levels of demand over time through the decentralised decision-making of individual market participants. This includes decisions on when, where and what type of new generation capacity to build, and when existing generation capacity should retire. Importantly, it also includes decisions by consumers on how much to consume at peak times. Prices play an important role in signalling the demand for capacity. These include prices in the "energy-only" spot market for electricity, and prices for contracts that are derived from the spot market. The desired outcome is therefore one in which these signals work effectively in delivering changes to the stock of installed capacity over time.

The CPRS and expanded RET do not change this broad dynamic, but they will change the environment within which it operates. The expanded RET promotes investment in renewable generation. In the medium term, this is expected to be dominated by wind. Wind plant is intermittent, meaning its installed capacity cannot be relied upon to meet demand at any given time. It delivers energy, but not capacity, to the market. Further, the energy it provides to the market is linked to prevailing wind speeds, and can vary substantially over short periods of time. Other things being equal, this should result in signals for types of generation which complement wind, i.e. deliver capacity, but not energy.

The CPRS increases the relative costs of carbon-intensive generation. It is likely to bring forward the retirement of the most carbon-intensive generation, and encourage investment in cleaner technologies. In the medium term, there is likely to be a switch towards gas generation. In the longer term, it is likely to involve other technologies such as Carbon Capture and Storage (CCS) and geothermal. Given that our review is focusing on the medium term, our primary focus in on scenarios involving greater use and expansion of the stock of gas-fired generation, and a contraction in the use of coal-fired generation.

Will the current energy market frameworks deliver?

Frameworks are robust

The energy market frameworks are likely to deliver timely and efficient investment if they are appropriately maintained.

This is because:

- The energy-only design of the wholesale spot market, and the financial contracts that are derived from it, provide effective signals on the future need for energy and capacity. This can translate itself into decisions on the timing, form and location of new generation capacity. The CPRS and the expanded RET do not alter the broad dynamic of this process, although they will affect the outcome.

- It is critically important in an energy-only market design for the maximum market price to be set at an appropriate level, and for it to be amended where necessary. The NEM has robust, evidence-based processes for this to occur.

- Submissions from market participants were supportive of the existing market design, and modelling undertaken by the AEMC Reliability Panel was consistent with the view that the existing framework is able to deliver desired outcomes if the settings are appropriate. The modelling also demonstrates the risk of inadequate investment if the maximum market price is too low.

- The existing framework for gas infrastructure investment appears to support the consequential investment in new pipelines to enable new gas-fired power generation to enter the market.

- The existing framework for electricity network planning and investment is premised on providing customers with reliable electricity supply, should that be part of the generation investment solution. These arrangements are discussed in chapter A6.

The reasoning for this position is discussed in the following sections.

Is this an issue for further consideration?

Not a material issue

Wholesale market and financial market signals

Wholesale market prices are calculated every thirty minutes for each of the five NEM pricing regions. Market participants enter contracts in expectation of what these prices will be. The value of these financial contracts (revealed in transactions, or implicit within a single business) provide sophisticated signals as to the capacity and the energy delivered to the market by generators.

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/MWh) in the spot market. In broad terms, swaps signal the value of energy and caps signal the value of capacity. Investment in new generation will be economic if the expected revenue stream from these contracts is sufficient to cover the cost of investment (including a return on capital) over the expected life of the asset. The combined signals provided through swaps and caps (and the variants of them traded in the market) can reveal what types of investment are most profitable. This is particularly relevant in the context of the expanded RET.

The expanded RET will, in the medium term, result in significant increases in installed volumes of wind generation capacity. This type of generation technology delivers energy, but not reliable capacity. This is because the output of wind generation depends on whether the wind resource is available. It cannot be relied upon to be available at peak times. Because of this, an increased use of wind generation will, other things being equal, reveal itself in greater demand for complementary generation which delivers capacity but not energy. The most economic form of generation in this context is OCGT. If the expected revenue from the sale of caps is sufficient to support investment in new OCGT plant, then we would expect it to occur. There is no obvious impediment to this occurring in the existing framework.

The CPRS is likely, in the medium term, to result in a shift from coal-fired generation to gas-fired generation. If the expected revenue stream from selling energy (swaps) and insuring against high prices (caps) is sufficient to cover the expected cost of new plant, then we would expect it to occur. The precise form of the new investment will depend on the timing of the different revenue streams. For example, if capacity is highly valued sooner compare to energy, then the most economic investment response might be an OCGT designed to be subsequently converted to a CCGT, consistent with the mode of operation shifting over time from peaking to mid-merit or base-load generation.

The CPRS’s impact on existing carbon-intensive coal-fired plant will increase the “noise” around the signals for new investment. This is because a prospective investor needs to predict the likely change in behaviour over time of existing coal-fired plant in order to value likely revenue streams. This is more difficult in the presence of the CPRS, because of the uncertainty over how and when the transition will occur. Given that coal-fired thermal plant is unsuited to frequent start-stop cycles and short-term running, permanent shutdown might be the best option. It may not be viable to maintain such plant purely to operate for a couple of hours during short-lived demand and price peaks. If existing plant retires earlier than predicted by investors, then there is a risk of capacity shortfall given the lead times involved for new investment. This issue is discussed in more detail in chapter A2.

Critical importance of appropriate regulation of market settings

Financial contracts, such as swaps and caps, are derivatives. Their value is derived from prices in the spot market. The value of the contracts, and therefore the influence they have on investment decisions, is significantly influenced by the maximum price permissible in the spot market. 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 standards of reliability.

In the NEM, the AEMC Reliability Panel has a role to review the market settings from the perspective of reliability, and propose changes when necessary. The proposed changes are assessed against the NEO, and implemented if we consider the change will promote the NEO. 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 AEMC Reliability Panel's 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. We are currently considering this proposal.

Submissions from market participants and modelling

There is significant qualitative and quantitative support to complement the conceptual reasoning as to why an energy-only market with appropriate settings can deliver efficient investment to support reliability. A number of submissions commented on the adequacy of the existing frameworks for investment, and the costs and risks of moving away from the energy-only design in the NEM towards forms of capacity market.[39]

Modelling studies undertaken by the AEMC Reliability Panel suggested an increasing risk of breaching the reliability standard if the maximum market price was retained at its current level of $10 000/MWh. Modelling commissioned by the AEMC Reliability Panel to update this analysis in the context of the introduction of the CPRS produces results consistent with the earlier conclusion.[40]

This updated modelling considered sensitivities of system reliability to variations in carbon prices, the maximum price cap and timing of the availability of low emission technologies.

39 AER, pp.2-5; Joint submission from CS Energy, Macquarie Generation, Origin Energy, Snowy Hydro, Stanwell, Tarong Energy and Eraring Energy, pp.5-7; Ergon Energy, p.3; TRUenergy, pp.12-13; VENCorp, pp.9-10; MEU, pp.17-18. Note that the MEU supported a capacity market.

40 Ergon Energy (p.6) states: "Given the Maximum Price Level (MPL) is proposed to increase to $12 500 from July 2010, this review would be to ascertain whether the climate change policies represent a material change necessitating a further future adjustment."

Modelling results indicated that variation in the maximum price cap was the dominant factor in influencing reliability – far stronger than variations in carbon prices or the availability of low emission technologies. Key findings of the modelling were as follows:

- For the range of carbon price paths studied[41] and where the maximum price cap is adjusted to $12 500/MWh and subsequently indexed to maintain its value in real terms, the energy-only market was, in principle, capable of producing the revenue necessary to support investment to meet the reliability standard on a whole-of-NEM basis. However, if the market price cap is retained at its current nominal level of $10 000/MWh, the market was unlikely to provide sufficient revenue to support enough investment to meet the standard.

- Within the range of scenarios studied, volumes of renewable generation up to the limits of penetration assumed in modelling seem able to be readily accommodated without material risk of breaching the reliability standard.

- Within the range of scenarios studied, the risks of breaching the reliability standard are not substantially affected by delays in the availability of new low-emission generation technology.

- Within the range of scenarios studied, the risks of breaching the reliability standard are not substantially affected by changes in generation capital costs or gas price paths.

The modelling did, however, highlight a risk of the reliability standard being breached in South Australia. This outcome was, however, did not eventuate when the possibility of investment in increased interconnector capability between Victoria and South Australia was allowed. Given that the findings noted above indicate that appropriate settings for the market price cap will enable such investment to occur if it is the efficient response to maintain reliability, this result also would appear to be consistent with the view that the current frameworks are robust.

Gas infrastructure investment

Greater investment in gas-fired plant will increase demand for gas. This will lead to a need to build more gas production and transportation infrastructure. Gas pipeline capacity is negotiated bilaterally. A lack of available capacity, but a demand for it, will create incentives for someone to invest in it. Because it is long term investment, most gas pipelines are underwritten using long term contracts. Because gas pipelines can offer "firm" access arrangements, this will provide certainty to gas-fired plant that fuel will be available. There are other relevant matters here such as managing the peakiness of demand, which we discuss in chapter A1.

41 CRA International modelling examined three different carbon price paths: 1) starting at $10/tonne of CO2e in 2020 and increasing by 4 per cent p.a. above inflation; 2) starting at $20/tonne of CO2e in 2020 and increasing by 4 per cent p.a. above inflation; and 3) starting at $30/tonne of CO2e in 2020 and increasing by 8 per cent p.a. above inflation.

We believe that the existing framework for delivering new pipeline capacity is capable of supporting the anticipated shift from coal to gas-fired generation resulting from the CPRS. The timing and size of the shift will be influenced by the cost of delivering new pipeline capacity (and by the gas price), but this is entirely appropriate. If gas prices and the cost of gas pipeline expansion mean that there are cheaper forms of carbon abatement, then the shift from coal to gas should be commensurately slower.

Electricity network investment

In some circumstances it will be more efficient for reliability to be met through augmentation to the transmission network, rather than by building additional generation capacity. This might be to gain access to surplus generation capacity in an adjacent region, or it might be to facilitate more effective use of capacity within a region.

The framework for network investment is discussed in more detail in chapter A6. From the perspective of reliability, we consider the existing framework of economic regulation to provide sufficient obligations and incentives to support efficient network responses. Further, we note the planned implementation of a NTP, and the planned reforms to the process of consultation and assessment around significant network investment (the RIT-T) as developments which further strengthen this regime.

Issue A4: System operation and intermittent generation

Chapter Summary

This chapter considers operation of the power system with increased intermittent generation. Changes in generation mix due to the new climate change policies may result in technical challenges for the power operating system. We consider that the existing frameworks are able to maintain a secure operating system in the context of large increases in intermittent generation.

Questions

A4.1 Do you agree that operation of the power system with increased intermittent generation is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

What is the desired market outcome?

The desired market outcome is to maintain a secure operating system that facilitates competitive energy markets in the context of large variability in generation outputs. In the NEM, NEMMCO maintains power system security by operating the market within the technical limits of the system. This prevents equipment from being overloaded. These limits are an input into the NEM's dispatch process.

Rapid, large changes in generation outputs can put pressure on the operating system. In particular, output swings greatly affect voltage and frequency levels, which must be kept within defined limits to keep the system secure and operational. The reasons for this are set out below.

- **Voltage:** Voltages that are too high or too low can result in increased power system losses, overheating of motors and other equipment and, at an extreme, system voltage collapse with consequent loss of customer load. The NER define the voltage standards within which NEMMCO must operate the power system.[42] The primary source of voltage control in the NEM is through sources of reactive power. Both NEMMCO and network service providers (NSPs) procure reactive power. NSPs procure it through generation connection agreements. NEMMCO can also procure additional reactive power from generators as a network control ancillary service (NCAS).[43]

42 See NER S5.1A.

43 NEMMCO may procure NCAS through contractual arrangements under NER clause 3.11.4. Some NCAS procured by NEMMCO does not relate directly to voltage control.

- **Frequency:** Variations in frequency beyond the tight tolerance can cause generation plant to "trip-off". Frequency is maintained by matching supply and demand. As soon as there is an imbalance, frequency will change, e.g. if demand is higher than supply, frequency will fall. Dispatch of different types of generation plant affects frequency. For example, the intermittent nature of wind generation means that its output can change quickly, causing supply-demand imbalances, which affect frequency. Wind plant also has no "inertia", so as the volume of dispatched wind plant increases, the power system becomes more sensitive to changes in the supply and demand balance. NEMMCO procures market ancillary services, usually referred to as frequency control ancillary services (FCAS), to manage frequency changes within the standards determined by the AEMC Reliability Panel.[44]

The expanded RET and, to a lesser extent, the CPRS will provide incentives to build new renewable generation capacity. Wind generation plant is expected to meet the majority of the expanded RET, with forecasts of around 6 000 MW of wind capacity by 2020.[45] Most of the wind plant is forecast to locate predominantly at sites in Victoria, New South Wales and South Australia. The analysis also indicates that new renewable generation investment is likely to "cluster", particularly in remote areas such as north-west Tasmania, the Eyre Peninsula in South Australia, the geothermal zones in South Australia (e.g. Moomba) and the western areas of New South Wales and Queensland, where solar energy is abundant.[46]

In this context, we consider whether the current energy market frameworks enable NEMMCO to maintain secure operation of the power system with greater clustering of renewable generation and greater penetration of intermittent plant, such as wind, with rapidly changing outputs.

Will the current energy market frameworks deliver?

Frameworks are robust

The frameworks enable the system operator to maintain a secure operating system that facilitates competitive energy markets in the context of large increases of intermittent generation.

This is because:

- Existing NEMMCO dispatch systems represent a solid foundation. A security-constrained dispatch, which jointly minimises the costs of meeting demand and maintaining frequency and voltage, is calculated every five minutes.

44 NER clauses 3.11.1 and 3.11.2 set out the provisions for frequency control. The AEMC Reliability Panel determines the frequency standards under NER clause 8.8.1(a)(2).

45 AEMC 2008 Survey of Evidence, p.38-39.

46 MMA 2008 Initial Market Issues paper, pp.37-38.

- A range of reforms progressed over recent years, such as the "Semi-Dispatch" Rule[47] and Australian Wind Energy Forecasting System (AWEFS), improve NEMMCO's ability to manage the power system with large increases in intermittent generation output.

- The current arrangements for setting, reviewing and amending, if necessary, technical standards (e.g. frequency and voltage levels, access standards) and procuring ancillary services and reactive power are sufficiently robust to respond to changes in the operating environment if they are required.

- Quick-start generation plants have market and commercial incentives to be available when intermittent outputs reduce to cover its contract position for high price events.

The reasoning behind this position is presented in the following sections.

Is this an issue for further consideration?

Not a material issue

Managing the power system with greater concentrations of intermittent plant

Improvements to power system operations to manage greater volumes of intermittent generation have already been identified, designed and implemented. From 1 May 2008, the "Semi-Dispatch" Rule requires all new wind generation plant greater than 30 MW to register as a "semi-scheduled generator". These improvements are incorporated into the dispatch engine, which every five minutes calculates the least cost way of using generation to meet demand while also maintaining frequency and voltage, and continuing to maintain a secure operating state across the network.

From 31 March 2009, NEMMCO will be able to integrate significant intermittent generation plant into the central dispatch process and projected assessment of system adequacy (PASA) processes in order to enhance system security and reliability. All new wind farms (and other intermittent plant) greater than 30 MW are required to register as a "semi-scheduled generator", submit and receive dispatch information in a similar manner to scheduled generation plant and limit their output at times when that output would otherwise violate secure network limits.[48]

The new AWEFS will increase the ability to accurately forecast wind generation. This will improve: the accuracy of NEM dispatch and pricing processes; load forecasts; and network stability and security. The AWEFS produces forecasts for all NEM wind farms (greater than 30 MW) in the dispatch, pre-dispatch, short-term PASA and medium-term PASA timeframes.

47 AEMC 2008, *Central Dispatch and Integration of Wind and Other Intermittent Generation,* Rule Determination, 1 May 2008, Sydney. ("Semi-Dispatch" Rule). Available: www.aemc.gov.au.

48 All wind turbines are designed with some sort of active power control, usually automated, to allow them to control their output, mainly during high wind speeds. Depending on its design, the rotor blades are turned to either increase or decrease the angle at which the wind strikes the blades, spilling the excess energy in the wind.

One of the project objectives is to extend forecasts over time to include other renewable types such as solar and tidal energy.[49] The AWEFS interface with NEMMCO's Market Management System (MMS) portal went live on 1 December 2008.[50]

Recent events in Germany and the United Kingdom, where effective system operation appears to have been hampered by a lack of transparency and control over intermittent generation plant, illustrate, the benefit of these changes.[51]

The above menioned initiatives provide NEMMCO with greater visibility and control over intermittent generation outputs, improving its ability to maintain secure operation of the power system.[52]

Responsiveness of non-intermittent generation

The spot, contract and FCAS markets provide a range of price signals to promote an appropriate level of flexible plant (and demand response) to supplement the variability and potential rapid change in wind outputs. Higher spot price volatility is likely with variable wind outputs and this provides incentives for quick start plant to be available to run, as do the prices in the FCAS market for fast-response sub-five minute services. Generation plant selling contract cover for high price events will also recognise the value of plant flexibility as it will need to be available to generate to cover its contract position. Some Stakeholders suggested that this might reduce the need for NEMMCO to procure "load following" ancillary services.[53] Chapters A2 and A3 consider the adequacy of the existing regime to deliver short and longer-term supply reliability more generally.

The semi-dispatch of wind generation and AWEFS significantly increase the flow of information to NEMMCO (and the market), particularly about what requirements for flexible operation and plant availability may be required. Other generation plant can then factor these conditions into their self-commitment times, output offers and rates of change (ramp rates).[54] One challenging circumstance may involve plant for which the cost of committing to operate are large, e.g. coal generation.[55] Evidence from South Australia indicates that thermal generation plant are currently managing this risk by offering their output at negative prices in some circumstances.

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49 See www.nemmco.com.au/psplanning/awefs.html.

50 NEMMCO Communications, NEMMCO Communication No. 3143 – Wind Generation Forecasting System MMS web interfaces in Production", e-mail, 1 December 2008.

51 As presented at the CIGRE Session 2008, Paris, 24-29 August 2008. Available: www.cigre.org/gb/events/session.asp.

52 Origin Energy, pp.8-9; NEMMCO, p.5; Australian Geothermal Energy Association, p.9.

53 Babcock and Brown Power, pp.12-15; Australian Geothermal Energy Association, p.11; ESIPC, p.6; TRUenergy, p.11; Western Power, p.5; Synergy, pp.10-12.

54 NER clauses 3.8.4, 3.8.17 and 3.8.18 and NEMMCO's spot market operation's timetable require generators to provide NEMMCO with information on their capacity profiles, energy availability, rates of change (ramp rates), and self-commitment and de-commitment times.

55 Pacific Hydro, p.10; NGF, p.9; UniQuest, p.7.

Operating the power system within secure voltage levels

Greater volumes of installed wind capacity increases the requirements for reactive power to control voltage[56] because increased wind output raises the potential for greater variations in system voltage levels. Unlike thermal generators, most wind plant do not have the facility to produce reactive power.[57] Consequently, this can increase the requirements for Transmission Network Service Providers (TNSPs) and NEMMCO to procure reactive power.

Part of this problem arises from the current flexibility in the connection access standards for new generation plant. Access standards define the level to which a new generation plant must be able to perform to be able to connect to the power system. Currently, the access standard ranges from the automatic access standard[58] to a minimum access standard.[59] While the NER prescribes a certain reactive power and voltage response capability for the automatic access standard, there are no such requirements for the minimum access standard.

That being said, the TNSP does not have to accept a connection application at the minimum access standard if it considers connecting the new plant at that standard could affect system security. NEMMCO also has an advisory role on access standards associated with system security. The TNSP can require the connecting party to install reactive power capability.[60] There are many options for minimising voltage issues:

- In South Australia, currently with the NEM's highest level of wind penetration, wind farms are required to meet the NEM automatic access standard. The South Australian regulator (the Essential Services Commission of South Australia (ESCOSA)) places this obligation in wind farm licence conditions as a way to minimise voltage problems on the power system.

- The United Kingdom, Germany, Canada and the United States have resolved voltage control issues by obliging wind farms (in their grid connection requirements) to be able to control their reactive power output to assist with controlling voltage.[61]

- Spain has dealt with the issue by providing for wind farms to vary their ratio of real power to reactive power with a bonus paid for supporting voltage control and penalties for not doing so.[62]

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56 ERAA, pp.6-9; ESIPC, p.7; Western Power, p.6.

57 Some of the newer design wind generation plant now have the facility to produce reactive power. These plants are comparatively more expensive. Other wind generation plants include static var compensators at the site to provide reactive power control.

58 The automatic access standard requires a generating unit to be capable of supplying and absorbing an amount of reactive power for any level of active power output and any voltage within certain limits. See NER clause S5.2.5.1(a).

59 The minimum access standard does not require any capability to supply or absorb reactive power. See NER clause S5.2.5.1(b).

60 For example, installing a static VAR compensator (SVC) could provide fast-acting reactive power.

61 ESIPC, Planning Council Wind Report to ESCOSA, April 2005, p.46.

62 Ibid.

The range of mechanisms within the current energy market frameworks can minimise the issues around voltage control. NEMMCO[63] and the AEMC Reliability Panel are both reviewing issues related to voltage control.[64] NEMMCO is reviewing the current arrangements for procuring network support (e.g. reactive power) more generally[65] while the AEMC Reliability Panel's Technical Standards Review is assessing the appropriateness of the automatic access standards and minimum access standards.[66] If NEMMCO or the AEMC Reliability Panel recommend improvements to those arrangements, these changes can be implemented through changes to the NER. Given this, we do not see a need for wider changes to the energy market frameworks.

Operating the power system within secure frequency levels

As the installed capacity of wind generation increases and is dispatched in place of thermal plant, the amount of inertia in the power system will also reduce. The power system will, therefore, be more sensitive to changes in frequency, particularly during a system disturbance or very rapid change in supply or demand on the power system. It will also be more difficult to manage the system frequency. There are currently no market settings relating to the provision of inertia to the power system.

NEMMCO's options for managing greater frequency variation are to dispatch greater quantities of FCAS or to increase the level of power system inertia.[67] Currently the NEM market systems co-optimise the dispatch of energy and FCAS. On the NEM mainland there are usually many base load generators connected so the levels of inertia and available FCAS are relatively high.

However, the situation in Tasmania may be different given it already has difficulties maintaining frequency control due to the high levels of wind generation, which does not provide inertia, and hydro generation, which is not naturally good at providing fast frequency control service. This is particularly true at times of light load and high import into Tasmania via Basslink when the level of inertia is low due to the relatively small quantity of connected hydro generation. Given the high opportunity cost for hydro generation, particularly in the current drought conditions, it is difficult to determine whether it would be more cost effective to provide greater levels of FCAS or more inertia, possibly through a new "inertia ancillary service" mechanism.

NEMMCO is already monitoring this issue across the NEM.[68] Furthermore, the changes that could address this issue, including amendments to the ancillary services market to provide a more cost effective solution could be brought about by Rule changes.

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63 NEMMCO, p.5.

64 For more information see the Reliability Technical Standards Review at www.amec.gov.au.

65 Required under NER clause 3.1.4(a1)(4), NEMMCO's Network Support Control Services (NSCS) Review is looking into the provision of NCAS, or NSCS more generally. The review's objectives are to: (1) identify and address issues in the current arrangements for TNSPs and NEMMCO to procure and deliver NSCS; and (2) identify, evaluate and make recommendations on potential alternative more efficient arrangements. See http://www.nemmco.com.au/powersystemops/168-0089.html.

66 AEMC 2008, AEMC *Reliability Panel Technical Standards Review*, Issues Paper, 9 May 2008, Sydney, p.4.

67 EUAA, p.15; Hydro Tasmania, pp.1-2, NEMMCO, p.6.

68 NEMMCO, p.6.

Issue A5: Connecting new generators to energy networks

Chapter Summary

This chapter considers the connection of new generators to energy networks. The expanded RET will stimulate investment in wind generation capacity. This is likely to be clustered in certain geographic areas, and remote from consumers and the existing transmission network. We consider that the existing model of bilateral negotiation for new connection will be unlikely to cope with large extensions to remote areas. There is significant risk of unnecessary costs and delays.

Questions

A5.1 Do you agree that the connection of new generators to energy networks is a significant issue that should be further progressed under this Review? If not, what are your reasons for reconsidering this position?

A5.2 Would any of the models identified in this chapter ensure the more efficient delivery of network connection services? In particular, with relation to these models:

- How should the risks of connection be most appropriately spread across new connection parties, network businesses and end use consumers?
- How do the connection charges change for connecting new generation plant and what benefits may arise?
- How do the costs for end use customers change and what benefits may arise?

A5.3 Are there any other potential models that we should consider to address this issue?

What is the desired market outcome?

The desired market outcome is that the connection of new generation to the energy networks is efficient and timely. To achieve this, the connection process needs to promote:

- the timely consideration of connection applications by TNSPs. This includes the consideration of large volumes of connection applications, and multiple connection applications in the same area;
- efficient cost-reflective pricing for new connections. This provides an efficient location signal to new connecting parties; and
- an efficient level of investment in connection assets and network infrastructure. This includes building an efficient level of network infrastructure that connects multiple connecting parties in the same location at the same time ("clustering") and also the potential for future connecting parties in the same area as existing generation plant.

The new climate change policies, particularly the expanded RET, provide incentives to build new low carbon intensive (renewable) generation. These new sources of generation will need to connect to the existing energy networks. Currently, renewable energy output provides about 15 000 GWh of electricity. The expanded RET increases renewable energy output requirements by 45 000 GWh to 60 000 GWh by 2020.[69] Modelling has forecast approximately 8 000 MW of new renewable plant by 2020 to meet this target.[70] Much of this renewable plant is forecast to be wind plant, which tends to be built in relatively small units with relatively low capacity factors (around 30 per cent).[71]

The CPRS is likely to stimulate new gas-fired generation connections due to their lower carbon intensity relative to coal-fired generation. For example, one study suggests that under a larger emissions reduction target (such as a 20 per cent reduction in emissions) an additional requirement of 5 000 MW to 7 000 MW of additional gas turbine capacity may be required by 2020.[72]

In this context we consider whether the existing energy market frameworks can deliver the efficient and timely connection of the forecast levels of new generation.

Will the current energy market frameworks deliver?

Some elements of the framework are likely to promote efficient market outcomes, while others are likely to struggle to deliver timely and efficient generation connections. Below, we first identify what elements of the framework are robust and then identify what areas are likely to require amendment.

Frameworks are robust

There are other aspects of the connection energy market frameworks that are likely to deliver efficient outcomes under the CPRS and expanded RET:

1. New gas-fired generation plants factor into their location decisions the direct costs of connecting to both the gas and electricity networks. These bilateral negotiation processes provide an efficient locational price signal as the new plant can factor into its location decision the relative direct connection costs to each energy network. Location decisions may also be informed by the level of congestion on both the gas and electricity networks, but this is a separate consideration and not a direct cost contributable to connection to the energy networks. We consider the affect of congestion on location decisions in Chapter 6.

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69 Council of Australia Governments (COAG) Working Group on Climate Change and Water, Design Options for the Expanded National Renewable Energy Target Scheme, 2 July 2008, p.4. Available: http://www.climatechange.gov.au/renewabletarget/consultation/pubs/ret-designoptions.pdf.

70 MMA 2008 Treasury paper, figure 3-6, p.39.

71 ROAM 2008 Market Impacts paper, pp.29, 32.

72 AEMC 2008 Survey of Evidence, pp.47-49`.

2. In its location decision, new generation plant may take into account the availability of excess transmission capacity (made available by generation plant exit). To the extent this occurs, this reduces the risk of some network assets becoming under-utilised or even redundant if generation plant entry and exit decisions lead to a shift in the overall location of generation.

Likely to require amendments

There are some fundamental elements of the existing energy market frameworks that are unlikely to deliver timely and efficient generation connections. The incentives introduced by the expanded RET are likely to heighten the issues related to the ability of TNSPs to process efficiently the expected large numbers of connection applications,[73] (i.e. due to large investment in wind farms). The issues include:

- The current framework may hinder commercial certainty and inefficiently increase investment costs for remote generation. This may be exacerbated where there are multiple connecting parties in the same place at the same time or the potential for future connection applications in the same areas as existing generation.

- The existing bilateral negotiation framework for connections between the TNSP and the connecting party may struggle to deliver efficient and timely investment for remote generation. This issue, however, was not considered a problem for the ongoing connection of new thermal plant.

The reasoning for these conclusions is presented in the following sections.

Is this an issue for further consideration?

Having identified the aspects of the framework that are robust and likely future amendments, we now consider whether or not these issues should be further considered. For the material issues, we highlight potential mitigation options in the final section of this chapter.

Not a material issue

New gas-fired generation plant factor into their location decisions the direct costs of connecting to both the gas and electricity networks. These bilateral negotiation processes provide an efficient locational price signal as the new plant can factor into its location decision the relative direct connection costs to each energy network. Location decisions may also be informed by the level of congestion on both the gas and electricity networks, but this is a separate consideration and not a direct cost contributable to connection to the energy networks. We consider the effect of congestion on location decisions in Issue 6.

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73 ROAM 2008 Market Impacts paper, pp.33, 38.

The bilateral negotiation arrangements in place for gas and electricity connections provide efficient locational signals. These arrangements require a connecting party to pay the direct connection costs to each the gas and electricity networks, ensuring the new generation plant factors the relative connection costs in its location decision.[74] While there was little consensus among submissions about whether the different regulatory regimes for gas and electricity skewed locational decision-making[75], we connsider the implications for "access arrangements" on locational decisions[76] in chapter A6.

In addition, the risk of redundant network assets does not appear material. Excess transmission capacity can be a location signal for new investment. Excess capacity as a result of generation plant exiting from existing coal regions may encourage growth in gas-fired technologies, depending on the associated investments in gas infrastructure, e.g. pipeline capacity and gas storage.[77] If significant assets did become redundant and the TNSP did not seek to manage the risk, like seeking to negotiate a lower cost for the network user, then NER clause S5.2.3 allows the AER to remove assets from the regulated asset base. This reduces the risk of end use consumers having to pay to maintain redundant assets.

This is a material issue

Multiple connections in the same place at the same time

The current connection framework makes it difficult for a TNSP to develop a connection solution that would be efficient for multiple connecting parties in the same location. There are two main limiting factors:

1. Each connecting party must negotiate its connection individually with the TNSP. This includes negotiating for the assets at the connection point and the extension[78] line from the generation plant to the connection point. Both of these augmentations are defined as negotiated transmission services in the NER.[79]

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74 A few submissions noted a preference to better align the connection regimes in the Victorian and other eastern state gas markets. Aurora (pp.5-6); ENA (p.10); ERAA (pp.7-8); Origin Energy (p.10).

75 Ergon Energy (p.8), Jemena (p.11), Grid Australia (p.12) and VENCorp (p.17) considered connection charges was only one of many locational price signals while the ERAA (p.7) and TRUenergy (p.14) considered them to be a key locational incentive.

76 ERAA, p.7; TRUenergy, p.12.

77 MMA 2008 Initial Market Issues paper, p.33.

78 An extension is an augmentation of a power line or facility outside the present boundaries of the transmission network owned or controlled by the network service provider (NSP).

79 The negotiated arrangements are a negotiate/arbitrate model, which means that parties are required first to seek to negotiate charges and other terms of connection and binding dispute resolution is available if an agreement cannot be reached. Generators can construct and own their extension facilities, or appoint another party to undertake this task.

2. The NER defines connection information as confidential, thereby preventing TNSPs from discussing one connecting party's information with any other prospective connecting parties.[80] The connection costs for the individual connecting party are currently, therefore, a function of the distance from the existing transmission network and the types of dedicated assets necessary for connection at the connection point. This creates incentives for generation plant to locate as close as 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. However, the confidentiality requirements prevent the TNSP from revealing to any applicant the presence of other applicants in the area. This means than even if a TNSP wanted to build a single connection asset and then allocate the costs directly attributable to each generator, it would be unable to provide each applicant with the reasoning behind this most efficient connection option. While the confidentiality requirements are designed to protect the commercial interests of connecting parties, it may actually be in the commercial interests of those same parties to consider these potentially more cost effective connection options. That being said, in bilateral meetings, some stakeholders commented that generators discourage co-ordinated connections as a way to protect their commercial interests. There is an important balance between facilitating more efficient and cost effective connections and maintaining commercial sensitivities.

Connection assets and the risks of predetermining their optimal size

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

TNSPs may not be willing to take on this risk. If the predicted generation does not eventuate, the TNSP would have a connection asset but no one to recover the cost from, leaving the TNSP with a "stranded asset". It is also unlikely that the initial connecting party would be willing to pay for the excess connection to facilitate future connection of a competitor, even if it could obtain a return when selling access to the connection asset.

The high costs of connecting may dissuade first mover incentives for remote generation plant.[81] While a cost-sharing scheme may partly alleviate this problem, there is still a risk of stranded connection assets.[82] The current NER may also discourage merchant funded connection or transmission assets.[83]

80 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.

81 ENA, p.11; Ergon Energy, p.9; Pacific Hydro, p.10; Uniquest, p.12.

82 ERAA, p.8; ESIPC, p.8.

83 Origin Energy, pp.11-13; Pacific Hydro, pp.10-11.

This is because the regulatory regime that applies to these investments is unclear, and they face the same stranded asset risks, affecting the ability to earn a sufficient risk premium. Merchant investors will not undertake such projects where the risks are significant.

End use customers do not bear any risk of stranded connection assets for connections built under the negotiated framework. The connecting party and TNSP share that risk. They do, however, bear some risk of stranding for connection assets built prior to the commencement of the negotiated framework (before 16 November 2006). Currently, those connection assets form part of the TNSP's regulated asset base. Through transmission use of system (TUOS) charges, consumers pay for the use of that regulated transmission network. Consumers' share of this risk is not material, however, for the reasons discussed below.

Processing a high volume of connection applications

Stakeholders agreed that TNSPs will find it difficult to process the high volume of expected connection applications, particularly given the requirements to consider each connection application individually and the NER confidentially requirements.[84] Recent estimates indicate that there are approximately 180 existing and prospective future wind farms.[85] Assuming the same number of new farms apply for connection each year, TNSPs may be expected to handle an extra ten or so connection applications each year; they currently receive around three a year.[86] 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.[87]

What are the possible mitigation options?

At this stage, we consider there are four broad options for addressing the shortcomings in the existing connection framework. These options retain, to varying degrees, some of its desirable features, including:

- efficient locational price signals as generators pay for the dedicated assets they require for connection (i.e. generators take account of the forward-looking cost of network assets that their connection would cause);

- prospective generators bearing the risks associated with investing in suitable connection assets; and

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84 Aurora Energy, pp.5-6; AER, p.7; Australian Geothermal Energy Association, p.15; Babcock and Brown, p.9; ESIPC, p.8; ENA, pp.11-12; ERAA, p.8; Jemena, p.11; NGF, p.12; NEMMCO, p.7; Origin Energy, p.11; TRUenergy, p.13; Clean Energy Council, p.7.

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

86 This estimate is based on a cursory examination of the TNSP Annual Planning Reports.

87 MMA 2008 Initial Market Issues paper, pp.37-38.

- bilateral negotiations providing a framework to agree terms suiting commercial need (e.g. commit the TNSP to deliver a project by an agreed date or be subject to liquidated damages).

The four broad options are:

- **Option 1:** Maintain the current regime of bilateral negotiations for network connection, but permit each TNSP to declare an "open season" for new connection applications in specified geographical areas. Connection applications made outside this "open season" would not be accepted. The definition of when and where the open seasons would apply would be consulted on by TNSPs through their respective Annual Planning Review processes (and the National Transmission Network Development Plan (NTNDP)[88]).

- **Option 2:** Separate the investment task in respect of each "cluster" into two parts: (a) a network extension to create a "hub" for each cluster; and (b) connection assets to connect individual generators to the "hub". The latter, (b), would continue to operate under the existing bilateral negotiation framework (subject to the hub being built). The former, (a), would be subject to a new regime for planning, charging and revenue recovery. This would involve:

  – candidate extensions (Network Extensions for Remote Generation or NERGs) being identified, but only proceeded with if an economic test (to be defined in the NER and consistent with the NEO) was met;

  – the economic test would involve (financially-backed) commitments by prospective generators to pay charges for use of the NERG. If these total commitments covered a pre-defined proportion of the estimated capacity cost of building the candidate extension (say, 50 per cent), then the economic test would be met;

  – charges to generators for using the NERG would be levied by the relevant TNSP and set (but not subsequently changed in real terms) at a level sufficient to recover the full cost of the extension if all of the anticipated future volume of generation (assumed in identifying it as a candidate extension in the first instance) actually connected; and

  – once the economic test was met, the project would be triggered as a contingent project from the perspective of the relevant TNSP's revenue allowances. This would mean that the risk of the anticipated volumes of generation not connecting – and the asset being underutilised – is borne by consumers, rather than the "first-mover" generators (as would be the case under the existing arrangements). In this context, the economic test represents protection for consumers in this risk-sharing.

88 The National Transmission Planner will be responsible for publishing the NTNDP, which will map out development strategies under a range of scenarios for the efficient delivery of transmission capability across national transmission flow paths.

- **Option 3:** As for option 2, except the economic test would be met if the National Transmission Planner deemed it to be met.

- **Option 4:** As for option 3, except the charges for using each NERG would be recovered from the generality of consumers in each TNSP's area (as is currently the case in respect of the shared network more generally) rather than the remote generators in the area serviced by the NERG. A variant of this model would be for the charges to be funded by an external source, e.g. Infrastructure Australia Fund.

As an aside, while we do not discuss them in the context of this issue, we are aware that adoption of any of these (or similar) options would exacerbate the current issues related to inter-regional TUOS charges. We consider issues relating to inter-regional TUOS charges further in chapter A6.

Issue A6: Augmenting networks and managing congestion

Chapter Summary

This chapter considers the ability of the existing frameworks to promote efficient use of and investment in the electricity network through decentralised decision making by individual market participants. This includes looking at how network congestion is managed and the materiality of the costs it imposes. While the expanded RET, under some scenarios may increase network congestion within and between regions, particularly due the new and different mix of generation, the analysis currently available is inconclusive as to whether this will lead to material increases in congestion. We are undertaking further analysis to determine the materiality of this problem. However, there are a number of factors that imply the potential for a problem with the existing market frameworks, specifically whether the current signals for "self-management" of network congestion are clear enough and strong enough in the new environment where congestion may be more material.

Questions

A6.1 Do you agree that the issue of network congestion and related costs requires further examination in this Review to determine its materiality? This includes considering whether the existing frameworks provide signals that are clear enough and strong enough in the new environment where congestion may be more material. If not, what are your reasons for reconsidering this position?

What is the desired market outcome?

The desired market outcome is for energy market frameworks to promote efficient use of and investment in the network through decentralised decision-making by individual market participants. This requires generators to have the right financial incentives on how to use the network, and where to locate new generation capacity. It also requires regulated networks to have the right incentives to operate and invest in networks over time. The incentives are created through regulatory obligations, market prices and network charges, and through the allocation and management of trading risk.

A key consideration in assessing actual outcomes against the desired market outcome is how network congestion is managed, and the materiality of the costs it imposes. Network congestion occurs when the cheapest mix of generation cannot be used to meet demand because of an inability of the network to handle the consequent flows of electricity. It is both a direct financial incentive, and a potential leading indicator of inadequate financial incentives. First, the presence of congestion might discourage a new generator from building at a particular location, because it represents a risk of not being able to generate the desired volumes of electricity. Second, if congestion is imposing significant costs on the market, then it might indicate that market participants are not paying due regard to the costs of congestion when they make locational decisions. The costs of congestion might relate to an inability to use the cheapest mix of generation, the costs of managing trading risk, or the costs of unnecessary network investment.

There is a minimum level of network congestion that is efficient. To build sufficient network so that it is never constrained will be prohibitively expensive. An alternative to building out the congestion is to manage it more effectively. The market framework, therefore, should deliver incentives that promotes behaviour that avoids unnecessarily high costs of managing congestion. While historic congestion costs in the NEM have been relatively low, the implementation of the CPRS and expanded RET will test this. These policies will shift the location of generation over time quite profoundly, as coal-fired generation is replaced with gas-fired generation, and as renewable generators connect in new parts of the network.

Will the current energy market frameworks deliver?

Likely to require amendments

The analysis currently available is inconclusive as to whether the CPRS and expanded RET will lead to material increases in congestion. We are undertaking further analysis to determine the materiality of this problem. However, there are a number of factors that imply the potential for a problem with the existing market frameworks. This is because:

- The CPRS and expanded RET will accelerate and alter patterns of investment in generation capacity over time, and the value of this investment will be very high. The expanded national RET is likely to be the stronger influence in the period to 2020, with the CPRS having longer term impacts as the carbon price increases and as new technologies become more commercially viable;

- the consequential investment costs on supporting network infrastructure will also be high;

- any weakness in the incentives for efficient investment and location decisions could increase the materiality of network congestion with significant implications for total costs to consumers. Hence, factors that might have been immaterial historically might be material concerns in the context of the CPRS and expanded national RET. The absence of robust charging arrangements for transmission investment to support greater inter-regional trade has already been identified in this context[89]; and

- in a more rapidly changing environment, the costs of managing the risks associated with congestion might be heightened, and the allocation of risks (and the tools available for managing it) might not be adequate.

We discuss the reasoning behind these conclusions in the next section.

89 The Hon Martin Ferguson, Chair MCE, Letter to Dr Tamblyn, Chairman AEMC re "National Transmission Planning Arrangements – Final Report", 5 November 2008. See www.mce.gov.au

Is this an issue for further consideration?

Likely to be a material issue

Level of congestion under the CPRS and expanded RET

The available evidence is not clear on the impact of the climate change policies on the likelihood of material and persistent congestion. We are continuing to investigate the materiality of the problem.

The consensus amongst stakeholders was that the introduction of new generation plant, largely driven by the expanded RET, would cause more congestion on the network.[90] For the most part, however, stakeholders did not provide evidence as to whether or not the problem would be material. That being said, ESIPC noted that not only was South Australia experiencing an increase in network congestion from wind plant investments, but that the congestion was having a market impact.[91]

There is modelling evidence to suggest that the congestion problem may be an issue both between and within regions. The location of new wind plant is considered the main driver behind changes in inter-regional flows[92] and increases in the incidence of intra-regional congestion.[93] The analysis is inconclusive on whether or not these changes may result in congestion materially affecting market outcomes.

Locational signals for new generation plant

It is important to have market signals that promote efficient locational decisions for the significant levels of new generation investment forecast under the CPRS and expanded RET. Some of the factors influencing generation location decisions include: cost of connection and extension assets (negotiated transmission services); the expected price in a region (otherwise known as the Regional Reference Price (RRP)) (and the likely price separation between regions); transmission loss factors; and the availability of fuel.

What is important is the collective ability of these market signals to drive efficient decisions over time. If we conclude that they do not, then the policy question is what element should be amended, and how. This should be determined by the relative costs and benefits, against the NEO. In this context, we note that stakeholders commented more extensively on the arrangements for transmission charging and access than the arrangements for wholesale pricing.

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90 Aurora Energy, p.6; ESIPC, p.9; ENA, p.12; Ergon Energy, p.9; Hydro Tasmania, p.2; Major Energy Users, p.9, 24; Origin Energy, p.18; Pacific Hydro, p.11; Synergy, p.14; TRUenergy, p.14; VENCorp, p.25.

91 ESIPC, p. 9.

92 ROAM 2008 Market Impacts paper, pp.36-40; MMA 2008 Initial Market Issues paper, pp.28-30.

93 AEMC 2008 Survey of Evidence paper, section 8. p.80.

Cost of connection and extension assets

As discussed in chapter A5, the current connection framework in the NEM requires new connecting parties to negotiate connection directly with a TNSP. The costs of connection include the costs that are directly contributable to their connection, e.g. their connection and extension assets.

This represents a relatively sharp locational signal. It is, however, limited to connection and extension assets.

Wholesale market pricing and settlement arrangements

In the NEM, all generators in a region receive the same price (the RRP). There are five regions, and prices are calculated every thirty minutes. The price is the marginal cost of meeting demand at a particular point in each region (the Regional Reference Node (RRN)).

Congestion can mean that the cost of meeting demand at the RRN is different to the cost of meeting demand at other points in the region. This is because congestion can limit the mix of generation that is capable of being used to meet demand at a particular point. This can create a trading risk for generators. There is a risk of a generator being required to generate less than it wants to at the prevailing regional price ("constrained-off"), or being required to generate when it does not want to at the prevailing regional price ("constrained-on"). The prospect of this occurring is a form of market signal.

If separate prices were calculated at more points on the network, the market signal derived from the risk of being constrained-on or-off would be reduced in strength. But direct price signals would be stronger. At the extreme, a price could be calculated separately for each point on the network ("nodal pricing"). This provides strong locational signals, but also creates significant additional trading risks. This is the risk of price differences between the generator's location and the locational at which a contract with a retailer is struck. This is known as "basis risk", and currently exists between NEM regions but not within regions.

Transmission access

Transmission access rights (physical or financial[94]) are an example of a risk management instrument. In the NEM, there is currently an "open access" transmission regime. This means that transmission access is allocated according to dispatched capacity rather than generation plant having guaranteed access rights to capacity on the shared network. That being said, in principle, the NER do provide for a generation plant to negotiate with a TNSP "financially-firm access" to the shared network. This is set out in NER rule 5.4A.

94 As a risk management instrument, financial transmission rights provide their holders with a revenue stream derived from the differences in nodal prices that occur when transmission limits bind.

In practice, however, there are a number of issues with NER rule 5.4A. Essentially, while the provision allows a generation plant to negotiate with the TNSP a set power transfer capability to the shared network, the TNSP's ability to deliver this service is limited by its lack of control over system operation. This is due to TNSPs being unable to control dispatch and influence flows across the network, therefore being unable to guarantee efficiently a particular generation plant firm access to the network.[95] As such, TNSPs are dissuaded from negotiating firm access with generation plant, particularly because NER rule 5.4A allows the generation plant to seek compensation from the TNSP if the negotiated level of firm access is not available.

Because NEM generators do not have firm access rights, they face a risk that the "quality" of their network access is adversely affected by the actions of other market participants. Other market participants do not factor in this risk management cost when they make locational decisions. This is therefore an area of the current framework where market signals are relatively weak, compared to frameworks that are used in other markets. However, this "quality" of transmission service is reflected in network charges. Currently, NEM generators do not face transmission use of system charges.

Transmission loss factors

Another form of market signal is transmission loss factors. For generation plant, Static Loss Factors (SLFs) reflect the amount of energy that is lost (e.g. in the form of heat) in the process of transporting energy from the generation plant to the RRN. Distance and voltage can affect losses, with losses being greater over longer distances and lower voltages.[96] SLFs provide a financial incentive for generators to locate at points, e.g. close to major loads, which result in lower losses.

While a SLF may inform a location decision, stakeholders indicated there may be a significant degree of uncertainty regarding the losses that NEMMCO applies from year to year.[97] Network flows, and therefore losses, can be significantly affected by new generation connections, particularly at relatively constrained parts of the network. For example, TRUenergy has cited an example of a year-on-year change of 25 per cent in the SLF.[98]

If SLFs are volatile year-on-year, then the effect of the locational signal is diminished, because it is not clear what is being signalled. This will be a consequent cost to managing SLF volatility. The impact on SLFs for other market participants is not factored in when an individual market participant makes a locational decision.

95 The TNSP could guarantee access by building a substantial amount of network capacity, but this is likely to be an inefficently expensive response.

96 Losses are a function of the square of the voltage, so are significantly higher at lower voltages.

97 Australian Geothermal Energy Association, p.6; ENA, p.13; ERAA, p.11; Ergon Energy, p.11; MEU, p.26; NGF, p.12; Origin Energy, p.16; Synergy, p.15; TRUenergy, p.17; Clean Energy Council, p.9.

98 TRUenergy, p.17. As an example, this would translate to a year-on-year change in a loss factor from 0.98 to 0.97. In the best-case scenario of dispatch volumes being unaffected, this would represent a reduction of 0.5 per cent in gross spot market revenue for the generation plant. It would be a must larger proportion of profit.

TNSP planning arrangements and responsibilities

Rapid increases in generation investment under the CPRS and expanded RET may place new challenges on TNSPs. The aim of the existing transmission planning arrangements is to ensure the efficient and timely supply of electricity to customers. This is achieved through Rule based and jurisdictionally-determined levels of reliability (reliability obligations). TNSPs can also undertake projects that deliver market benefits. Primarily, these are projects that influence the dispatch of generation so that electricity can be delivered more efficiently. TNSPs are not obliged to undertake projects that deliver market benefits. Prior to undertaking either of these projects a TNSP is required to undertake the Regulatory Test.[99]

The primary focus of network planning is on reliability projects that address demand-driven congestion. This focus presents a potential issue under the CPRS and expanded RET.[100] Should there be more supply side driven congestion, due to new generation entering the market and new network flows from existing generation, there is likely to be an increased need for market benefits projects. The framework for assessing projects and the incentives on TNSPs will influence whether projects that deliver market benefits will be undertaken.

Most market benefits projects are expected to be treated as contingent projects.[101] While the contingent project framework removes the previous disincentive for TNSPs to undertake market benefits projects, it now leaves them financially neutral. This is because it only allows for cost recovery.[102] Stakeholders are concerned that this may mean that TNSPs may delay consideration of and investment in these types of projects. [103] In this light, TNSPs may need to consider a revised approach for network planning and investment going forward.

The current Regulatory Test appears sufficiently flexible to account for benefits from transmission projects that flow from the expanded RET and the CPRS.[104] The impact of the CPRS can be incorporated as a cost while the relative costs of renewable generation plant will reflect the value of Renewable Energy Certificates (RECs).[105] However, there may be benefit in clarifying the treatment of the climate change policies in the Regulatory Test. A supporting consultancy paper provides more information on this issue.[106]

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99 The existing Regulatory Test looks at projects that: (1) maximise the net economic benefit to all those who produce, consume and transport electricity in the market (market benefits projects); or (2) minimise the present value of costs of meeting reliability requirements (reliability projects).

100 Babcock & Brown, p.9; Ergon Energy, p. 9; Grid Australia, p.17; Hydro Tasmania, p.2; Origin Energy, p.14; Pacific Hydro, pp.11-13; Stanwell, p.2; and UniQuest, p.11.

101 A contingent project is a project that is uncertain but may be required to achieve the TNSP's capital expenditure objectives. The revenue allowance is contingent on various triggers being met. See NER rule 6A. 8.

102 This includes an allowance for a reasonable return for the risks employed to be recovered.

103 Grid Australia, pp.15-16; Origin Energy, p.7; Pacific Hydro, pp.11-13; UniQuest, p.11.

104 Grid Australia (pp.18-19) and VENCorp (p.17) commented that they were not sure the Regulatory Test captured environmental benefits.

105 See Allen 2008 Renewables and RIT-T paper.

106 Ibid.

Market benefits projects may be more likely under the proposed RIT-T which will also be sufficiently flexible to account for the expanded RET and the CPRS.[107] The RIT-T merges the existing two limbs of the Reliability Test, removing the potential artificial incentive for TNSPs to focus only on the reliability aspects of transmission projects. The RIT-T also includes the ability to estimate the "option value" benefit of transmission investment. This flexibility may allow TNSPs to consider projects that: (1) take into account future transmission requirements, such as building more line capacity today that takes account of expected future requirements like new connections; or (2) value options that defer investment to provide time to look into a range of future augmentation options, such as the short term use of demand management. The concurrent "Review of Demand Side Participation in the NEM" considered the particular issues around demand-side participation and the RIT-T in Stage 1 of the review.[108]

The NTP[109] and the AEMC, through the Last Resort Planning Power (LRPP), may also have a role in identifying investments that may provide market benefits. The NTP's role will have responsibility for planning with respect to national transmission flow-paths and can look beyond regional issues. This remit is likely to include consideration of possible interconnector upgrades. The LRPP[110] is a mechanism for triggering cost-benefit assessments of potential projects where the TNSP has not acted, providing transparency and moral persuasion for TNSPs to identify and test potential new transmission projects.

The NTP, LRPP and RIT-T provide a framework under which market benefits projects can be more actively considered in the future. There is still a question as to whether these reforms provide sufficient incentives for TNSPs, given their overarching objective is to plan the network to meet reliability obligations that are customer-driven.

TNSP operations

The current regulatory arrangements apply a service performance target incentive scheme to TNSPs. The purpose of the scheme is to provide incentives to make the network available at times that it is most valued by the market. Incentives in this regard attempt to reward (or penalise) TNSPs for behaving in ways that increase (or decrease) the value that users gain from the network, such as scheduling outages at off-peak times. The NER put a limit on the bounds of risk and reward to between one and five per cent of regulated revenue.[111]

107 The MCE has provided the AEMC with Rule changes to implement the RIT-T as well as the National Transmission Planner. See: www.mce.gov.au.

108 The Alternative Technology Association, p.2; Total Environment Centre, pp.4-5.

109 The MCE proposed a Rule change to implement the NTP. See www.mce.gov.au.

110 Under NER clause 5.6.4 the AEMC can direct a TNSP to identify a potential transmission project and apply the Regulatory Test if there is a significant network problem identified but no one is looking at addressing it.

111 The current scheme, as determined by the AER, sets the maximum increment or decrement a TNSP may earn is 1 per cent.

The arrangements do not, however, provide TNSPs with broader incentives to maximise line ratings or available network capability (either through the service incentive scheme or through financial obligations to generators and customers). While TNSPs have an agreement[112] to maximise operational line ratings using dynamic ratings NEM-wide where possible, it is only voluntary and does not apply to network capability.

Strengthening the incentives to maximise available network capability and line ratings can improve the use of the existing network. All other things being equal, this can allow for better management of congestion and potentially delay the need for network augmentations.

Transmission charging arrangements

The current regional model of transmission charging does not handle the costs of "inter-regional" investment well.[113] The current pricing arrangements allow for TNSPs to recover the costs of building and operating the network from customers within their own region. There are limited arrangements for charging customers in adjoining regions for the costs of augmentations or network operation that deliver market benefits in those adjoining regions (inter-regional TUOS). At present, there is only one inter-regional TUOS arrangement in place.[114]

Concentrations of renewable energy sources, and therefore investment, in certain regions may lead to an increase in power exports from those regions than would otherwise occur in absence of the CPRS and expanded RET. Where there are no arrangements for inter-regional TUOS, customers in the exporting region would pay for network investments to facilitate those exports and would also face higher energy costs as well. Customers in the importing region would benefit from lower energy costs without having to pay for the network assets enabling the power transfers.[115]

Neither customers in the exporting nor importing regions would face transmission charges that properly reflect the network assets they are using and the benefits they derive. As inter-regional flows increase, the scale of the inefficiency becomes larger.

As requested by the MCE[116], we consider a need to improve the existing inter-regional transmission pricing arrangements, particularly in light of the climate change policies.[117]

112 TNSPs have agreed to a NEM wide approach to determining static and dynamic operational ratings and have agreed to maximise line ratings by using dynamic ratings where possible.

113 AER, p.8; Australian Geothermal Energy Association, p.16; ESIPC, p.2; Origin Energy, p.15; VENCorp, p.18.

114 Victoria and South Australia are the only jurisdictions that have an arrangement for inter-regional charging.

115 This assumes power flows from lower-priced regions to higher-priced regions.

116 The Hon Martin Ferguson, Chair MCE, Letter to Dr Tamblyn, Chairman AEMC, 5 November 2008. See www.mce.gov.au

117 AER, p.8; Australian Geothermal Energy Association, p.16; Babcock & Brown Power, pp.15-16; ESPIC, p.1; EUAA, p.9; Grid Australia, pp20-21; Origin Energy, p.8; VENCorp, p.18.

Issue A7: Retailing

Chapter Summary

This chapter considers the jurisdictional price regulation and RoLR arrangements. The CPRS and expanded RET introduce new and potentially uncertain costs into the supply chain for wholesale energy. These higher costs also mean higher prudential costs for retailers. We do not consider that the current retail price regulation arrangements are sufficiently flexible to be able to cope with the potentially large and rapid changes in retailer costs. We also consider that the regulatory contingency plans for handling the financial failure of a retailer arrangements (RoLR) are not adequate. While there are a number of processes underway to investigate potential changes to address these issues, we consider there is a risk if these reforms are not progressed and implemented in line with the introduction of the CPRS and expanded RET.

Questions

A7.1 Do you agree that the current inflexibility in the retail price regulatory arrangements is a significant issue that should be progressed further under this Review? If not, what are your reasons for this position?

A7.2 Do you agree that the limitations with current RoLR arrangements are a significant issue that should be progressed further under this Review? If not, what are your reasons for this position?

A7.3 Are there any additional options that could supplement the processes currently under investigation to address these issues?

What is the desired market outcome?

The desired market outcome is for the energy market frameworks to promote and support healthy competitive retail markets that deliver efficient prices and services to energy customers. Competition between retailers will, over time, reveal different businesses and business models to be more profitable than others. This, in turn, is likely to see some retailers exit the market, while other businesses may grow in size and some new businesses may enter the market.

A key element of the framework is to ensure competitive retailers can charge cost-reflective prices. Where competition is not fully effective and jurisdictional retail price regulation is in place, these arrangements need to be sufficiently flexible to respond to large changes in costs that are beyond a retailer's control, such as those forecast under the CPRS and expanded RET.

To the extent that retailers do exit the electricity and gas market, the energy market framework should have a contingency plan in place to protect customers should that retailer's exit be quick or unexpected. Retailers are the interface between the end consumer and the supply chain, managing the risk and transaction costs of purchasing wholesale energy and transporting it to customers. A "safety net", such as the existing mechanism of the RoLR, can help minimise the risk that a consumer will be exposed to the risks previously managed by its retailer, by providing a process to transfer that customer to an alternative retailer.

A retailer's own costs are a very small proportion of its total costs. The bulk of its costs represent the costs of buying wholesale energy, including prudential obligations, and network charges, which an individual retailer has only limited control over. Wholesale electricity costs are likely to increase under the CPRS and expanded RET.[118] Wholesale gas prices on Australia's eastern seaboard are also likely to converge towards international parity, although the pace of this will be influenced by the timing of Liquefied Natural Gas (LNG) terminal developments.[119]

The White Paper assumes that these higher costs will be passed through to consumers. It estimates retail electricity prices will consequently increase by around 18 per cent and retail gas prices by 12 per cent. Across all households, this would lead to an average increase in spending of $4 per week on electricity and $2 per week on gas and other household fuels.[120]

We consider in this issue whether the energy market frameworks for retailing are able to accommodate these changes while maintaining the effectiveness of retail competition and viability of retailers.

Will the current energy market frameworks deliver?

Framework is not sufficiently flexible

The current arrangements for jurisdictional price regulation are unlikely to promote and support the desired market outcome. This is because:

- there is likely to be a large cost increase for retailers;
- the current regulatory arrangements do not appear sufficiently flexible to enable retailers to manage these cost increases. The consequential costs of this inflexibility are high; and
- the current RoLR arrangements are inadequate and, if tested, may impose substantial costs on the energy markets; and
- while there are existing processes investigating potential changes to address these issues, there is a risk of the recommended changes being implemented too late.

This is therefore a material problem and warrants further consideration in this Review. The reasoning for these conclusions and possible mitigation options are presented in the following sections.

118 AEMC 2008 Survey of Evidence, p.64.

119 AEMC 2008 Survey of Evidence, pp.28-29.

120 Australian Government, Carbon Pollution Reduction Scheme - Australia's Low Pollution Future, White Paper, Volume 2, December 2008, p.17-3.

Is this an issue for further consideration?

This is a material issue

Changes in 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 for the reasons discussed below. The supplementary AEMC 2008 Retail Arrangements paper provides more detail on energy retailer costs.

- **Wholesale energy prices increase.** Wholesale electricity and gas prices are both forecast to increase.[121] There is no consensus on whether electricity price volatility will increase, though there is consensus that gas demand is likely to become more variable.[122]

- **Prudential and credit support requirements increase.** Increases in price and price volatility will correspondingly increase prudential and credit support requirements for NEM retailers[123] and gas retailers participating in the Victorian balancing market. The prudential costs for NEM retailers are likely to be substantial. NEM prudential requirements can take account of any "re-allocation" transactions or offsets expected in the immediate future. For example, requirements may be offset by financial contracts with generators, subject to the generator agreeing. In addition, we are currently considering a Rule change proposal about using Futures contracts in a similar way.[124] Stakeholders commented that the current financial climate may make it more difficult for retailers to obtain prudential coverage[125] and that this may lead to retailer exit.[126] Options that help NEM retailers manage prudential requirements will become increasingly important as wholesale costs rise.

- **Risk management instrument costs increase.** Higher wholesale energy prices may increase the costs of risk management instruments. The demand for these instruments is likely to increase at the same time that fuel prices for gas-fired peaking plant (that generally provide insurance coverage for high spot prices). While there is currently a lack of liquidity in the contract market beyond 2010 due to policy uncertainty around the climate change policies, this is likely to resolve itself once the CPRS policy is clarified.[127]

121 AEMC 2008 Survey of Evidence, pp.64-70.

122 AEMC 2008 Survey of Evidence, pp.73-75.

123 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.

124 See the proposed National Electricity Amendment (Futures Offset Arrangements) Rule 2008 proposed by Australian Power & Gas, Infratil Energy Australia and Momentum Energy. Available: http://www.aemc.gov.au/electricity.php?r=20080204.095152.

125 ENA, p.15.

126 Origin Energy, p.17; Synergy, p.16.

127 Australian Power and Gas, pp.2-3; ERAA, p.12; Origin Energy, p.17; Synergy, p.16, TRUenergy, p.18.

- **Lack of working capital.** Stakeholders also advised that the direct costs of the CPRS and electricity market volatility related to its introduction may lead to cash flow problems for energy market participants.[128] Depending on the design of the CPRS permit auctions, generators may face issues in sourcing sufficient working capital to allow them to purchase their required permits. Gas retailers, who also have direct permit obligations, may face similar problems. Although electricity retailers will not face direct obligations, substantial increases in wholesale electricity prices may also require them to have access to additional amounts of working capital to purchase electricity from the market pool. The extent of this problem will depend upon the ability of retailers to source additional credit support which, given the current financial climate, may be a material problem.[129]

Retail price regulation flexibility is variable

Inflexible and time consuming regulatory processes are a risk to retailer viability. Every Australian jurisdiction regulates retail prices differently and the flexibility within these arrangements varies.[130] For example, the form of price regulation in some jurisdictions may prevent the efficient pass through of increased costs. Under the CPRS, this could create a point of tension should the price of carbon permits change over the 12 auctions each financial year[131] but the form of price regulation is unable, or not sufficiently flexible, to capture these variable costs. This may be particularly relevant for non-host retailers.[132]

This issue is discussed in more detail in Chapter 3 of the our Second Final Report of the Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia.[133]

Victoria is the first jurisdiction to legislate to remove price regulation from 1 January 2009.[134] This is likely to place Victorian retailers in a reasonable position to competitively set prices that reflect the new higher costs under the CPRS and expanded RET.

128 Stanwell Corporation, p.4; ESAA, p.4.

129 While the NSW regulator, IPART, currently includes an allowance for the cost of working capital, it is unclear whether the allowance will assist in managing volatility under the CPRS. See: IPART, "Promoting Retail Competition and Investment in the NSW Electricity Industry – Regulated Electricity Tariffs and Charges for Small Customers 2007-2010, April 2007, p.56.

130 The AEMC 2008 Retail Arrangements paper describes the jurisdictional price regulation regimes.

131 Australian Government, CPRS White Paper, p.9-12.

132 AER, p.8

133 AEMC 2008, *Review of the Effectiveness of Competition in Electricity and Gas Retail Markets in South Australia*, Second Final Report, 18 December 2008, Sydney.

134 *Energy Legislation Amendment (Retail Competition and Other Matters) Act 2008* (Vic).

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. 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.[135] However, accounting for changes to wholesale energy costs and associated hedging costs are much more difficult to manage under the existing arrangements, particularly given the wholesale cost component is the most substantial one in a regulated tariff, as is accounting for the cost of financing greater prudential coverage as wholesale prices increase.

Households only see price increases, however, if regulated tariffs are amended to provide for the cost pass through. At a minimum, delays in adjusting the regulated tariffs may mean that retailers are under-recovering costs by as much as 18 per cent for electricity customers and 12 per cent for gas customers.[136] This is an unsustainable situation for retail businesses.

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.[137] Previously competitive retailers may also find themselves in unnecessary financial distress because of rising wholesale energy costs and prudential requirements. Prudential costs might be magnified further by developments in global credit markets.

In the longer term, inflexibility can affect the incentives for making investment decisions. If there is uncertainty about recovering costs in the future then the appetite of retailers to forward contract may decline. If investment decisions are delayed, the risk of energy supply shortfalls may increase.[138]

As such, the existing levels of flexibility in the regulatory arrangements represent a significant risk for retailers given the large forecast cost increases related to the CPRS and expanded RET.[139]

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135 While it may be simpler to identify the cost for gas retailers for purchasing carbon permits compared to electricity retailers, there are other related costs that may not be as easy to quantify. One cost may be the administrative costs of purchasing the permits. Another is the costs of "unaccounted for gas" in pipelines. It is unclear how pipeline operators will distinguish between gas losses and metering errors for the purposes of purchasing carbon permits to cover unaccounted for gas. The initial thinking is pipeline owners will pass these costs through to their customers, including retailers.

136 Australian Government, CPRS White Paper, p.17-3.

137 In meetings with stakeholders, anecdotal evidence indicated that some non-host gas retailers have actively encouraged non-profitable customers to return to the regulated offer.

138 See chapter A3 for a discussion on investment decisions.

139 AER, p.8; Babcock and Brown Power, p.17; Australian Power and Gas, p.2-3; ENA, p.14; ERAA, p.11; ESAA, p.3; Ergon Energy, p.11; Jemena, p.13; NGF, p.16; Origin Energy, p.4; Scott George, p.8; Synergy, p.16; TRUenergy, p.17.

Retailer of Last Resort arrangements may compound the problem

The RoLR 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.[140]

The problems with the existing RoLR schemes include: the high cost of sourcing wholesale energy (and prudential coverage) at short notice; delays in customer information transfer to RoLR; limited cost recovery arrangements; the lack of RoLR arrangements for gas; and inconsistency between jurisdictional RoLR schemes.[141]

These issues are magnified, the larger the size of the failed retailer increases. So too is the level of disruption and major inefficiencies as the market is brought back to some form of stability. There are several medium sized[142], privately owned, non-host (and non-RoLR) retailers in the different regions of the NEM, whose exit could place a substantial burden on the RoLR. In addition, only one jurisdiction has given consideration to the failure of a 1st tier retailer; it is likely that the sheer size of the event could cause severe disruption and major inefficiencies as the market was brought back to some form of stability.

The impact of a "host" retailer exiting the market where it is the sole electricity host retailer (and, as in South Australia, also acting as the RoLR[143]) could be particularly disruptive.[144]

There is also the possibility that retailer financial distress or failure may occur prior to commencement of the CPRS and expanded RET, triggering RoLR much sooner than expected. If a vertically integrated generator-retailer ("gentailer") finds the generator component of its business facing the risk of insolvency[145], this could also trigger insolvency of the retailer arm depending on the business's structure. This would trigger a RoLR event under the Rules, the importance of having a national RoLR framework in place as soon as possible.[146]

140 AEMC 2008 Retail Arrangements paper, p.18.

141 AEMC 2008 Retail Arrangements paper, pp.16-17.

142 For this review, "medium sized" retailers has been taken to mean those retailers with between 100 000 and 1 million customers. Source: NERA Economic Consulting, "The Wholesale Electricity Market in Australia – a Report to the Australian Energy Market Commission", March 2008, p.51.

143 ESTA Utilities is officially the RoLR in South Australia but has subcontracted this role to AGL. See A the AEMC 2008 Retail Arrangements paper for further detail.

144 ENA, p.14.

145 See Chapter 2A for a further discussion on this issue.

146 In order to minimise possible disruption to the market, it is recommended that a national RoLR framework by operational at least 15 months prior to the start of the CPRS and expanded RET, i.e. by 1 March 2009.

The costs to the energy market will be higher if a retailer fails and the RoLR does not work well. This is widely recognised as a weakness in the market arrangements. For example, the MCE is currently developing a national RoLR framework for inclusion in the National Energy Customer Framework.[147] The CPRS and expanded RET increase the potential cost of this weakness in the regulatory regime.

What processes are investigating potential changes to address the issues?

While the issues in the current arrangements create a more risky operating and investment environment, there are a number of processes underway to investigate potential changes to address these issues. There is a risk, however, that any recommended changes may be implemented too late to manage the issues heightened by the commencement of the CPRS and expanded RET.

- MCE recommendation for the CPRS costs pass-through: The MCE commented on the importance of flexibility at its December 2008 meeting, noting that carbon-cost pass-through in retail energy markets was important to the function of the CPRS. At that meeting, Ministers agreed to propose to COAG that it amend the AEMA to specify that, where retail prices are regulated, energy cost increases associated with the CPRS shall be passed through to end-use consumers.[148] However, noting that the recommendation was only announced on 12 December 2008, a work program to implement this policy position remains to be established and progressed.

- MCE-SCO development of a national framework for RoLR: The MCE is currently developing a national framework for RoLR. The MCE anticipates releasing a policy paper around March 2009, which will likely outline a proposed national framework.[149] It anticipates that the Second Exposure Draft on the National Energy Consumer Framework, due in mid 2009, will include provisions to implement the national RoLR framework. Any potential delays in this timetable could mean that the recommended changes to the RoLR framework may not be in place before the start of the CPRS and expanded RET.

- AEMC Reviews of Effectiveness of Competition and Regulatory Reset Periods: The MCE's policy position is for energy price regulation to be removed in jurisdictions where competition is found to be effective.[150] We have now completed reviews in Victoria and South Australia but it is unlikely to have complete reviews in other jurisdictions prior to 1 July 2010. Even if all the reviews were complete, there is a time lag between presenting our final recommendations to the relevant state or territory government and that government making its final decision on the matter. As such, future decisions to remove price regulation are unlikely to be made in sufficient time to alleviate the problems that retailers are likely to face as costs increase in light of the climate change polices.

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147 Further information on the status and content of this review is available in the AEMC 2008 Retail Arrangements paper, p.18.

148 Ministerial Council on Energy, 17 Meeting Communiqué, December 2008, Adelaide, p.2.

149 The policy report will respond to the consultancy report prepared by NERA Economic Consulting (NERA) and Allens Arthur Robinson (AAR): NERA and AAR, "Retailer of Last Resort – Review of Current Jurisdictional Arrangements and Development of a National RoLR Framework", Report prepared for the MCE Retail Policy Working Group, 30 September 2008.

150 As set out in the COAG Amended 2006 Australian Energy Market Agreement (2006 AEMA), the MCE policy framework is to remove price regulation over time when there is effective competition between retailers in each jurisdiction.

Issue A8: Financing new energy investment

Chapter Summary

This chapter considers the potential changes to the total value of investment in the energy sector as a result of CPRS and the expanded national RET. It also considers the extent to which current energy market frameworks influence how the required level of investment may be financed. The CPRS and expanded national RET will require a large step increase in investment in the energy sector. We believe that existing frameworks support the efficient financing of this additional investment. Robust market designs and stability and predictability in the regulatory regime are key factors in this regard. This view also reflects, in part, the Electricity Supply Assistance Scheme included in the CPRS White Paper, and its implications for the environment for investment. We note that the cost, availability and form of finance will be influenced by a wider set of factors, including in response to recent developments in global financial markets.

Questions

A8.1 Do you agree that the current energy market frameworks do not impede the efficient financing of the significant increase in investment implied by CPRS and expanded national RET? If not, what are your reasons for this position?

What is the desired market outcome?

The desired market outcome is for the required level and form of new investment in supply side infrastructure in energy markets to be financially viable at reasonable cost, and that energy market frameworks do not increase unnecessarily the risks and costs of investment.

The desired market outcome will need to be delivered by a mix of government-owned and privately-owned bodies, by regulated and unregulated businesses, and across both gas and electricity. It will required significant injections of both equity and debt finance, from investors and lenders in Australia and overseas.

The context for this is a very large, step-change in the value of new investment as a result of CPRS and the expanded national RET. The CPRS is likely to result, over time, in a shift from coal-fired generation to gas-fired generation and renewables. The precise form of the new investment will depend on the timing of the different revenue streams. The expanded RET will result in significant increases in renewables. This is likely to be in the form of wind generation capacity. Investment in electricity generation over the past ten years has averaged around $1.5 billion per year.

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 over ten years on new thermal plant to replace coal-fired generation retirements over the same period.[151] 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.[152] Forecasts suggest that this expenditure will continue or may increase.

The context also reflects the wider environment for investment. This encompasses the recent development in global financial markets, and the medium term implications for financing. Importantly, it also includes the precise form of the CPRS set out in the White Paper, including the Electricity Sector Adjustment Scheme (ESAS) and its implications for the environment for investment in energy infrastructure.

Will the current energy market frameworks deliver?

We believe that the existing energy market frameworks support the efficient financing of the significant additional investment implied by CPRS and the expanded RET. This is because:

- Frameworks for regulated investment are robust, and have been demonstrated to be capable of sustaining significant capital investment programs;
- The wholesale market designs and the supporting governance arrangements provide a robust environment within which unregulated investment options can be assessed and implemented – and there is significant evidence of investment being delivered in practice.
- The energy sector in Australia would appear to be relatively well positioned in terms of the broad investment environment, including as a result of the final form of the CPRS and ESAS set out in the White Paper.

We discuss the reasoning behind these conclusions in the next section.

Is this an issue for further consideration?

Frameworks are consistent with efficient financing of new investment

The environment for investment has changed substantially in recent months. While the full implications of developments in global financial markets remain highly uncertain, there are some likely consequences. First, a more conservative approach to debt financing, with lower average gearing and more exacting debt covenants. Second, increases in risk premia to remove the perceived under-pricing of risk. Third, potential reductions in the risk-free rate. In this context, it is even more important that additional factors within the specific frameworks for energy markets do not make the financing task more difficult.

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151 Firecone 2008 Investment paper, p.1.

152 Ibid.

Frameworks for regulated investment

There is currently a well defined regulatory regime for investment in new electricity generation and transmission capacity. This regime is provided for within the market Rules and establishes the standards to be met, revenues required to recover efficient costs, and appropriate incentives for performance improvement. In the gas sector, there are different levels of economic regulation for pipelines.[153] To date have, the funding of these regulated assets been considered low risk and are considered to offer a revenue profile consistent with the needs of relevant investors.[154]

Noting this, a number of stakeholder have suggested that there are provisions within the current regulated regime that could be improved to increase certainty for recovery the costs of investment.[155] However, these comments relate to how the framework is applied, rather than the design of the frameworks themselves.

There is significant experience of the recent past of the regime supporting significant capital investment programs, and the framework of regulatory consultation and decision-making appears to be robust to more extensive capital expenditures programs if such investment is required and efficient.

Frameworks for unregulated investment

Whilst the electricity and gas market designs are different, including for the Western Australia and Northern Territory, these markets contain a range of mechanisms and signals to ensure to promote efficient investment in, reliable and secure energy supplies.

The ability of the frameworks to deliver the revenue that sustains efficient investment in new generation capacity is discussed in more detail in chapters A3 and B3, and in chapter A1 and B1 in the related context of gas markets. This discussion illustrates that different types of market design can deliver the desired market outcomes. The NEM adopts an energy-only wholesale market design, while the WEM provides explicitly for capacity payments. Both of these markets design have effective and transparent governance arrangements. This is an important component part in providing predictability of revenue streams to support new investment.

These frameworks have delivered significant investment over the past ten years. Investment in electricity generation over the past ten years has averaged around $1.5 billion per year. Investment in gas pipelines in the period 2000 to 2006 has seen the network increase by around 6 000 kilometres at a total cost of around $2.5 billion.

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153 Full regulation applies to certain covered pipelines. Under full regulation, a service provider is required to submit (in an access arrangement) the tariff and non-tariff terms and conditions of access to the services provided by the pipeline for the AER's approval. Other covered pipelines may be subject to light handed regulation. In this case, a service provider need not submit an access arrangement to the AER. However, it must provide certain terms and conditions of access on its website. Other pipelines are not subject to regulation and are not subject to the economic regulation provisions of the NGL and NGR.

154 See S3 2008 Financing Paper.

155 Aurora Energy, p.8; Australian Geothermal Energy Association, p.20; ENA, p.16.

Broader investment climate

The energy sector competes with other sectors in the Australian economy for finance for investment, and with other markets globally. Robust regulatory frameworks and market designs are a key factor in creating the appropriate environment for new investment. However, there are also significant wider influences.

The CPRS White Paper contributes to the more general investment climate in two ways. First, it provides more certainty on the range of likely carbon prices under the CPRS, and therefore the consequences for different investment options. This is likely to increase the ability of investors to make decisions. Second, the ESAS provides an estimated $3.5 billion in support of adversely affected coal-fired generators. This is intended to enhance the environment for future investment. Perceptions of policy risk are particularly significant for the expanded national RET because much of the investment would be uneconomic without the revenue provided through the RET.

PART B: Issues for the Review – Western Australia

Introduction

This Part provides our analysis of seven of the eight set of issues identified in the Scoping paper for Western Australia. (We consider Issue 8 to be broader than any specific market, and this is therefore covered by chapter A8.) Western Australia, whilst a signatory to the overarching Australian Energy Market Agreement, independently operates its own electricity and gas markets.

Overview of energy markets in Western Australia

Western Australia's electricity supply industry is comprised of several distinct systems, none of which are interconnected to the NEM. The South-West Interconnected System (SWIS) around Perth and the south-west of the State is by far the largest of these, and is the only system in Western Australia to support a wholesale market. This Part therefore focuses on arrangements in the WEM in the SWIS.

Western Australia has the largest gas reserves in Australia, with substantial offshore gas fields in the Carnarvon, Browse and Bonaparte basins. Importantly, a large proportion of Western Australia's gas production is exported as LNG.

Interaction with other initiatives

It is important to note that many of the issues discussed in this Part for Western Australia have already been identified by market institutions in Western Australia. In particular, the Economic Regulation Authority (ERA) released a discussion paper in June 2008 that considered a range of issues related to the WEM[156], and has subsequently reported to the Minister for Energy. The Office of Energy has been undertaking a Retail Market Review, which reported, in part, in April 2008.[157] Additionally, a Renewable Energy Working Group (REWG) has been set up under the auspices of the WEM Market Advisory Committee to give further consideration to many issues related to Renewable Energy.

Therefore, where we identify an issue that is well defined in Western Australia or is specific to that jurisdiction, and for which a clear mitigation course has already been identified, we note this but assume that this can be resolved by the relevant institutions in the jurisdiction (i.e. the ERA, the Office of Energy, or through a change to the WEM Rules).

However, issues that are broader in nature, less well developed or which have significant parallels with issues in the national arena, we propose to include in this Review, and therefore set out possible mitigation options in this Part and request views. We may, nevertheless, ultimately conclude that any resulting measures should be best implemented through jurisdiction specific institutions.

156 ERA, "*Discussion Paper: Annual Wholesale Electricity Market Report to the Minister for Energy*", 5 June 2008.

157 Office of Energy, "*Draft Recommendations Report - Electricity Tariff Arrangements*", April 2008.

Issue B1: Convergence of gas and electricity markets

Chapter Summary

This chapter examines the convergence of gas and electricity networks in Western Australia. We consider that, due to relatively high gas prices in Western Australia, the CPRS is likely to prompt little fuel switching from coal to gas for baseload or high merit generation. However, the expanded RET is likely to lead to an increased role for low-merit gas-fired plant to back-up the increased amount of intermittent wind generation. There are potential issues regarding short-term access to gas supplies and pipeline capacity, but if these become material it is likely they will be addressed through specific initiatives in the jurisdiction.

Questions

B1.1 Do you agree that the convergence of gas and electricity markets in Western Australia is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

What is the desired market outcome?

The desired market outcome is for market arrangements to support competitive and effective trading and investment in gas and electricity markets across a wide geographical area and for a range of demand profiles.

As demand for gas and electricity grows, the interactions and reliance between the gas and electricity markets also increase. Arrangements that enable how to best co-optimise the desired market outcome in both energy markets become increasingly important. This does not necessarily point to greater convergence in market designs, however. Rather, the arrangements require:

- sufficient flexibility and responsiveness in gas market mechanisms, like bilateral contracting for gas supply, the role of third party access to the gas networks and the ability to access storage capacity that can manage greater and more volatile gas demand; and

- operational procedures and processes that respond to emergency supply shortfall situations in one energy market to recognise and have regard to the potential consequential effects for the other energy market. For example, the decision to curtail supply to a gas-fired generation plant needs to take into account the impact on the electricity market of a reduction in that gas-fired plant's output.

Under the CPRS and expanded RET there is unlikely to be a material increase in gas-fired generation as a base load fuel in Western Australia because gas is comparatively a very expensive fuel, with gas prices at international parity levels.

Any increase in gas-fired generation is likely to be back up for an increase in renewable generation, such as wind. This could also contribute to a more volatile gas demand on what is considered an already limited pipeline network.

Will the current energy market frameworks deliver?

Frameworks are robust

Current energy frameworks seem well placed to continue to support competitive and effective trading and investment in gas and electricity markets in Western Australia, with Western Australian institutions already considering any issues in this area. This is because:

- New entry into the market for baseload or high merit generation in Western Australia is currently predominately coal-fired due to the relatively high gas prices, and this is likely to continue under the CPRS.

- Under the expanded RET, there is likely to be an increasing role for low-merit gas-fired plant to back-up wind generation. A number of pre-existing issues regarding short-term access to gas supplies and pipeline capacity have been identified, and it is likely that if these become material they will be addressed through specific initiatives in the jurisdiction.

- Due to the dominance of one gas pipeline in Western Australia, there is a potential security of supply issue. However, with the ability of gas-fired generators to run on distillate, and the increasing amount of coal-fired generation entry, it seems unlikely that the introduction of the CPRS and expanded RET will exacerbate the current situation.

The reasoning for supporting these conclusions is presented in the following sections.

Is this an issue for further consideration?

Not a material issue

Fuel switching

The incidence of fuel switching as a result of the CPRS will be a function of the relative prices of gas and coal.[158] Gas tends to be more expensive in Western Australia than in east coast jurisdictions, due to its linkage to international gas prices as a result of exporting LNG. The ERA has noted indications that gas prices in Western Australia more than doubled between 2006 and 2007, to reach $5.50 to $6/GJ. This compared to about $3/GJ in Victoria and New South Wales, and about $2.50/GJ at that point in time in Queensland.[159]

Western Australia has significant coal resources, with over 40 per cent of the total installed capacity in the SWIS being coal-fired.[160] The relatively high gas prices in

158 Fuel switching in this context is an increase in the use of gas relative to coal for electricity generation as a result of changes in new investment from coal-fired to gas-fired generation.

159 ERA, Discussion Paper: Gas Issues in Western Australia, June 2007, p.8. Available: http://www.era.wa.gov.au

160 See:http://www.energy.wa.gov.au/cproot/1268/11070/Generation%20capacity%2005082008.pdf

Western Australia have led to a large cost difference between gas-fired and coal-fired generation, such that much of the current new entry into the SWIS generation market is coal-fired.

As a result of the coal-gas cost spread being greater in Western Australia than in the NEM, the marginal abatement costs under the CPRS will be different, to the extent that coal seems likely to maintain its cost advantage. The lowest-cost option for Western Australian generators is therefore likely to be for them to pay for carbon permits, as opposed to switch fuel to gas, as would be the case in the NEM.

As a result, the cost of generation in Western Australia would increase, but there would be no fuel-switching, and therefore no change to the current situation as regards new generation entry by baseload or high-merit plant. In this respect, the existing market frameworks would seem robust against the introduction of the CPRS.

Gas-fired generation as a back up to wind

Fuel switching in the short-term in Western Australia is likely, however, as a result of the expanded RET. Currently, the most mature and viable zero-emission technology is wind. Given that Western Australia has a high number of areas of good wind resource, the incremental cost of renewable generation over and above wholesale prices is, on average, lower in Western Australia than in the NEM. This is likely to result in significant entry by wind generation in Western Australia.

However, one implication of this likely high level of wind generation will be an increased requirement for back-up generation to be available when wind turbines are not able to generate. Gas-fired generation is the most appropriate technology to fulfill this role (in the absence of significant hydro resource in Western Australia), due to its ability to quickly ramp output up and down. This will require access to gas supplies and transportation capacity on a variable basis.

The primary gas pipeline in Western Australia is the Dampier to Bunbury Natural Gas Pipeline (DBNGP). Access to the DBNGP is currently regulated under the *National Gas Code* by the ERA,[161] and the pipeline has undergone significant capacity expansions over the last few years. However, it has been reported that securing access to capacity on the DBNGP is becoming increasingly difficult,[162] and this view was backed up by a stakeholder who suggested that the DBNGP is fully contracted for capacity, and is unlikely to have spare capacity until 2016.[163] While the DBNGP could be upgraded if the capacity was fully contracted (for instance, by a baseload generator), the existing pipeline is highly congested such that intermittent gas plant may not be able to acquire non-firm transportation capacity.

The opportunities for obtaining short-term gas supplies and access to gas pipelines may be more limited in Western Australia than in the jurisdictions participating in the BB and STTM. However, there is a process for trading capacity on the DBNGP, and there was, for a period, a gas bulletin board in Western Australia.

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161 Implementation of the National Gas Law in Western Australia is subject to pending legislation in the Parliament of Western Australia.

162 Ibid, p.44.

163 Synergy, p.4.

Under the access arrangements for the DBNGP, there is both a nominations process and a trade or transfer process. Under the nominations process, shippers must specify their nominations for a gas day by no later than 14:00 on the previous day. The pipeline operator must notify the shippers of daily nominations for the gas day by no later than 16:00 on the previous day.

Following the Varanus Island incident on 3 June 2008, and the resulting shortages of gas supplies in Western Australia, a gas bulletin board was put in place by the Independent Market Operator (IMO) in Western Australia. This bulletin board provided a platform where trade between buyers and sellers whose bids/offers overlapped were facilitated on a voluntary basis. Gas was exchanged at Dampier, and therefore traders were required to make their own transport arrangements. This service was thus more akin to the STTM than to the BB recently implemented on the east coast.

However, as a result of the partial resumption of gas supplies from Varanus Island, and no gas being offered for sale on the bulletin board since 29 August 2008, the IMO recommended to the Office of Energy (OOE) that the bulletin board be closed down. This was accepted and the bulletin board ceased operation on 13 October 2008.

Although the bulletin board was introduced as a result of exceptional circumstances, its closure could indicate a lack of demand for this type of service at the current time, although it could equally be reflective of difficulties potential buyers have in accessing capacity to the DBNGP.

However, in its 2008 annual market report Discussion Paper, the ERA identified a specific issue with the current frameworks for the short-term trading of gas and electricity in Western Australia in that there is a inconsistencies between the respective timings of pipeline nominations on the DBNGP and submissions for the Short-Term Energy Market (STEM) in the WEM.[164] Those participants that source gas from the DBNGP for generation in the WEM and who wish to participate in the STEM must make STEM submissions in the morning of the Scheduling Day (which is the day before the Trading Day). However, participants only receive confirmation of the availability of capacity on the DBNGP at 16:00 on the Scheduling Day (see above). These participants must therefore make STEM submissions based on estimates of gas availability for the following day.

Participants that do not receive their expected quantities of gas may be required to operate on liquid fuel, having submitted STEM bids and offers on the assumption they would operate on gas. This situation can have implications for the financial positions of these market participants. The ERA has raised various options for addressing this disconnect, such as moving the STEM closer to real time and introducing multiple gate closures. A further option would be to revise the operational processes on the DBNGP.

A risk that the existing gas markets in Western Australia are not flexible and responsive enough to handle the increased volumes and highly variable supply requirements of gas generation, was raised by a stakeholder, who also suggested that

164 ERA, Discussion Paper: Annual Wholesale Electricity Market Report to the Minister of Energy, 5 June 2008, p.25.

this is exacerbated by the limited gas storage facilities in the State.[165] It was suggested that, in the absence of adequate gas storage, short-term gas markets/swaps and adequate non-firm gas transportation arrangements, peaking generators will need to either book firm capacity and make long-term fixed bilateral commitments, resulting in an economic inefficiency to be borne by the market and end use consumers or be dual-fuelled and use distillate, with the associated environmental impacts.[166]

Clearly, if the only method of providing gas to gas-fired peaking plant resulting from an increase in intermittent renewable generation in Western Australia was through the provision of additional pipeline capacity then this would result in significant additional costs. However, it is not clear that there is any fundamental reason as to why there is relatively little gas storage capacity in Western Australia, and therefore any reason as to why the market would not respond to provide additional capacity should it be required.

It would also seem possible that gas-fired peaking generators would place more value on gas at times at which they have a demand than some other consumers of gas with long-term supply and pipeline access contracts. Therefore, there may be merit in providing additional short-term markets for gas and pipeline capacity. Western Power suggested that for the current levels of around 200 MW of wind capacity, there is a requirement for about 60 MW of gas turbine capacity for load following purposes.[167] According to Synergy, as there is currently over 1300MW of wind capacity seeking connection to the SWIS, it might be that in the future there will be significantly more demand for short-term gas trades.[168] Consequently, the ERA has already given consideration to addressing the current timing imbalance between STEM submissions and operational procedures on the DBNGP.

Security of supply

An increasing reliance on gas-fired generation in general, and on the DBNGP in particular, could also lead to issues with respect of security of supply. This was illustrated by the Varanus Island incident, which resulted in the loss of 35 per cent of the State's gas supplies, and led to the recommissioning of a number of coal-fired generators.

The dominance of one pipeline in delivering gas to generation and demand centres was noted. It was suggested by a stakeholder that insufficient gas supplies would result in a shift to distillate generation.[169] Given this likely response, and the increasing amount of coal-fired generation entry into the SWIS, it seems unlikely that the introduction of the CPRS and expanded RET will exacerbate any security of supply issues in Western Australia.

165 Synergy, p.4.
166 Synergy, p.5.
167 Western Power, p.5.
168 Synergy, p.8.
169 Synergy, p.6.

Issue B2: Generation capacity in the short-term
Issue B3: Investing to meet reliability standards with increased use of renewables

Chapter Summary

This chapter considers two issues in respect of Western Australia: generation capacity reserve levels in the short-term; and the longer term ability of the existing frameworks to support the efficient and timely delivery of new generation capacity, including to complement potentially large volumes of wind generation capacity. We consider that the capacity market has resulted in the presence of adequate generation reserves in the short-term, and appears to be well placed to attract new investment in the longer term. However, wind generation delivers energy, and can only be relied to a very limited degree to deliver energy at times of peak demand. We have consequently identified a potential risk of an under-provision of back-up generation. It is, therefore, critically important that the processes for reviewing and amending market settings (e.g. the allocation of capacity credits) are robust.

Questions

B2.1 Do you agree that generation capacity in the short-term in Western Australia is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

B3.1 Do you agree that investing to meet reliability standards with increased use of renewables in Western Australia is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

What is the desired market outcome?

The desired market outcome is for installed generation capacity to track required levels over time through the decentralised decision-making of individual market participants. This includes decisions on when, where and what type of new generation capacity to build and when existing generation capacity should retire. Importantly, it also includes decisions by consumers on how much to consume at peak periods. The WEM, unlike the NEM, has a capacity market in addition to an energy market. The objective of the capacity market, the Reserve Capacity Mechanism, is to ensure that the SWIS has adequate installed capacity available from generators and demand-side management options so as to:

- meet the forecast peak demand after the outage of the largest generation unit and while maintaining some residual frequency management capability, in nine years out of ten; and

- limit energy shortfalls to 0.002% of annual system consumption.[170]

The Reserve Capacity Mechanism aims to remove the need for high and volatile energy prices that are required in an energy-only market (such as the NEM) to provide adequate revenue to cover the capital costs of peaking plant and to trigger new investment. Energy prices are instead capped to relatively low levels (compared to the NEM),[171] with the Reserve Capacity Mechanism contributing to generator capital costs. The intention is that these payments can fully fund capital costs for peaking plant, and can contribute towards a baseload generator's capital costs.

Under the Reserve Capacity Mechanism, each retailer is allocated a share of the total capacity necessary to meet the above reserve capacity target. It is then required to secure Capacity Credits to cover that obligation. A Capacity Credit is effectively installed generation or demand-side management registered with the IMO. Retailers can either procure these credits bilaterally or purchase them from the IMO. The IMO may run an annual auction on behalf of retailers to procure additional credits if the total capacity requirement is not met through bilateral trade.

The CPRS and expanded RET are likely to change both the levels of capacity that will be required and the type of capacity that is made available. In this chapter we consider whether the existing framework in Western Australia is able to accommodate these changes, both to ensure sufficient generation capacity in the short term (chapter B2) and to lead to appropriate investment to meet the reliability standards with the increased use of renewables (chapter B3).

Will the current energy market frameworks deliver?

Frameworks are robust

We consider that the energy market frameworks in Western Australia are robust and will deliver sufficient generation capacity in the short-term and new investment in the longer term to meet reliability standards, particularly with the increased use of renewable generation.

- The WEM, through the Reserve Capacity Mechanism, has successfully provided incentives for the entry of new generation in the short-term. Sufficient capacity is currently "locked-in" to meet the reserve capacity target until October 2011.

- The Reserve Capacity Mechanism also, therefore, appears to be well placed to attract new investment in the longer term. While we have identified a specific issue with regards to the allocation of Capacity Credits to intermittent generation, and a consequential risk of an under-provision of back-up generation, we believe that this can be reviewed and, if necessary, addressed through the Rule change process that is a feature of the current framework in Western Australia.

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170 IMO, Wholesale Electricity Market Design Summary, September 2006, p.29.

171 The Maximum STEM Price in the WEM is $286/MWh (with an Alternative Maximum STEM Price of $763/MWh for facilities operating on liquid fuel e.g. distillate or oil). This compares to a maximum price, the market price cap (VoLL) in the NEM of $10 000/MWh. (The AEMC Reliability Panel has recommended that VoLL be increased to $12 500/MWh and is preparing a Rule change to submit to the AEMC to this effect.)

Is this an issue for further consideration?

Not a material issue

Generation capacity in the short-term

The Reserve Capacity Mechanism in the WEM is administered by the IMO. Each year the IMO prepares a Statement of Opportunities that projects capacity requirements for the SWIS for each of the next ten years. The Statement of Opportunities is used to set the actual Reserve Capacity Requirement for the period October to September starting in the second year following the release of the report. For the July 2008 report, this period was from October 2010 to September 2011.

The July 2008 Statement of Opportunities was the fourth such annual report to be published by the IMO. It identified a Reserve Capacity Requirement for the 2010-2011 Reserve Capacity Year of 5 146 MW.[172] In August 2008, the IMO announced that a total of 5 258.55 MW of Capacity Credits had been assigned.[173] To date, no Reserve Capacity Auctions have been required.

The Reserve Capacity Mechanism appears successful at attracting new investment and providing incentives for plant availability. For example, increasing Reserve Capacity Requirements have been met by significant new generation entry. As noted in chapter B1, there are currently a number of coal-fired generators planned or under construction. A number of gas-fired, predominately peaking plant, and a number of wind farms, as discussed elsewhere in this Part B, are also planned or under construction.

Any uncertainty over the potential introduction of climate change policies appears not to have had a material effect on generation investment in the WEM. There is, therefore, not a short-term reliability issue in Western Australia.

Investing to meet reliability standards with increased use of renewables

The introduction of the CPRS and, in particular the expanded RET, is likely to lead to a significant increase in the amount of renewable generation, especially wind farms, connected to the SWIS. It has been suggested that there is already 1 300 MW of wind capacity seeking connection to the SWIS.[174]

Wind generation is intermittent and it is this quality, rather than its renewable nature, that may potentially pose a reliability issue. This is because significantly less reliance can be placed on intermittent generation being available to generate at times of system peak demand. This issue is exacerbated in Western Australia as peak demand occurs in summer when there are high temperatures, and wind speeds are generally lower at such times. Therefore, the Reserve Capacity Mechanism needs to provide incentives for sufficient back-up capacity to be available such that the reserve capacity target can be met.

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172 IMO, Statement of Opportunities, July 2008, p.4.

173 See:http://www.imowa.com.au/Attachments/RC_Attachments/SummaryofCapacityCreditsfor2008 Reserve Capacity Cycle.pdf

174 Synergy, p.9.

Under the WEM Rules governing the Reserve Capacity Mechanism, existing intermittent generators are entitled to Capacity Credits based on their average sent out generation over the preceding three years.[175] For new intermittent generators, the amount of credits is based on an expert's opinion of what the generator's sent out energy would have been, had the unit been in operation over that period.[176] For example, the 80 MW Emu Downs Wind Farm has been allocated 31.105 MW of Capacity Credits (equivalent to 38.9% of rated capacity).[177]

However, there is no guarantee that an intermittent generator would be able to make its average level of output available at times of system peak demand. Indeed, as highlighted above, there may be reasons why generation at peak is likely to be less than average. Therefore, wind generation may be allocated too many Capacity Credits, with the consequence that too few credits are procured from back-up plant. As the amount of wind capacity connected to the SWIS increases as a result of the expanded RET, it is possible that the risk of reliability targets not being met may increase.

It may, therefore, be appropriate to review the Capacity Credit methodology and assess whether revised assumptions regarding intermittent generation are necessary. For instance, in Western Power's submission to the ERA on its 330 kV electricity transmission upgrade from Pinjar to Geraldton, Western Power and its consultants CRAI considered the likely contribution to peak summer demand of the 90 MW Walkaway Wind Farm, located close to Geraldton. They concluded that "based on data from South Australian wind farms, Western Power estimates that the Walkaway Wind Farm can provide approximately 5 MW of firm peak capacity".[178] (This is equivalent to 5.6 per cent of rated capacity.)

However, although we believe that there would be merit in a review, we have concluded that the energy market frameworks in Western Australia remain robust in this instance, given that the methodology is contained in the WEM Rules. Any revised methodology could be set out in a self-contained rule change and the option of proposing a rule change is open to any party. We also understand that the Office of Energy is already considering this issue.[179]

A further issue raised by a stakeholder in response to the Scoping Paper was that the regulated retail tariffs, currently capped below cost-reflective levels, will act to limit the investment in generation, particularly renewable schemes, going forward. While the evidence in terms of the amount of prospective generation does not seem to fully support this view, we agree with the stakeholder:

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175 Rules 4.11.1(d) and 4.11.3A.

176 Rule 4.11.1(e).

177 http://www.imowa.com.au/Attachments/RC_Attachments/SummaryofCapacityCreditsfor2008 Reserve Capacity Cycle.pdf

178 CRA International, Reinforcement Options for the North Country Region: Public Version, 30 March 2007, p.7.

179 Frontier 2008 WA and NT Market Implications paper, p.49.

> that it is critical that the costs arising from the schemes be allowed to flow through fully to wholesale and retail electricity prices to create the required incentives for demand reduction and other efficiency measures.[180]

As such, we believe this issue would most effectively be addressed at cause, and we consider the issue of regulated retail tariffs being capped below cost-reflective levels in chapter B7.

180 Synergy, p.6.

Issue B4 – System operation and intermittent generation

Chapter Summary

This chapter considers operation of the SWIS with increased intermittent generation. Changes in the generation mix due to the climate change policies may result in technical challenges for the power operating system. We consider that the existing regime in the WEM of having a single participant bear the main responsibility for balancing the system is not sustainable in light of the likely increased presence of wind generation.

Questions

B4.1 Do you agree that, given an increasing amount of intermittent generation, system operation in Western Australia is a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position?

B4.2 Would any of the options identified in this chapter improve the efficiency of the balancing process in the WEM? In particular, we would welcome views on:

- the practicality of introducing a competitive balancing regime;
- other solutions (such as moving gate closure or introducing centralised wind forecasting) that could reduce the impacts in the balancing market of forecasting errors; and
- the most appropriate charging regime for ancillary services in the WEM.

B4.3 Are there any other potential models that we should consider to mitigate this issue?

What is the desired market outcome?

The desired market outcome is to maintain a secure operating system that facilitates competitive energy markets in the context of large variability in generation outputs. In the WEM, system management maintains power system security by operating the market within the technical limits of the system. Rapid, large changes in generation outputs can put pressure on the operating system. In particular, output swings greatly affect voltage and frequency levels, which must be kept within defined limits to keep the system secure and operational. The reasons for this are set out below:

- **Voltage:** Voltages that are too high or too low can result in increased power system losses, overheating of motors and other equipment and, at an extreme, system voltage collapse with consequent loss of customer load. The WEM Rules define the voltage standards within which System Management must operate the power system.[181] System Management proposes requirements for dispatch support services, and procures these from Verve Energy and other market participants.[182]

- **Frequency:** Variations in frequency beyond the tight tolerance can cause generation plant to "trip-off". Frequency is maintained by matching supply and demand. As soon as there is an imbalance, frequency will change, e.g. if demand is higher than supply, frequency will fall. Dispatch of different types of generation plant affects frequency. For example, the intermittent nature of wind generation means that its output can change quickly, causing supply-demand imbalances, which affect frequency. Wind plant also has no "inertia", so as the volume of dispatched wind plant increases, the power system becomes more sensitive to changes in the supply demand balance. System Management proposes requirements for and procures ancillary services, such as load following, spinning reserve and load rejection reserve, from Verve Energy and other market participants to manage frequency changes.[183]

As noted in Part A, the expanded RET and, to a lesser extent, the CPRS will provide incentives to build new renewable generation capacity. Wind generation plant is expected to meet the majority of the expanded RET, with forecasts of around 1 GW of wind capacity by 2020 in Western Australia.[184] Given that Western Australia has a high proportion of productive wind sites relative to other areas of the country, Western Australia is likely to move to greater wind generation earlier than the NEM.[185] Other zero-emission technology, such as solar, geothermal and tidal technologies, are only likely to mature in the longer term for Western Australia.[186]

In this context, we consider whether the current energy market frameworks enable System Management to maintain secure operation of the power system with greater clustering of renewable generation and greater penetration of intermittent plant, such as wind, with rapidly changing outputs.

Will the current energy market frameworks deliver?

Likely to require amendments

The current energy market framework in Western Australia may not result in the maintenance of a secure operating system that facilitates competitive energy markets in the context of large variability in generation outputs. This is because:

181 WEM Rules, clauses 3.3, 3.4, and 3.5.

182 System Management may procure dispatch support services through ancillary service contracts with market participants other than Verve Energy, after obtaining the approval of the Economic Regulation Authority under clauses 3.11.8A and 3.11.8B. Dispatch support service is any other ancillary service that is needed to maintain power system security and reliability that are not covered by the other ancillary service categories.

183 WEM Rules clauses 3.9 and 3.10 set out the provisions for load following, spinning reserve and load rejection reserve ancillary services.

184 Frontier 2008 WA and NT Market Implications paper, p.45.

185 Frontier 2008 WA and NT Market Implications paper, p.43.

186 Frontier 2008 WA and NT Market Implications papers, p.42.

- The existing regime of having a single participant bear the main responsibility for balancing the system is not sustainable in light of the increased presence of wind generation, as this is likely to increase the need for system balancing services.

- In addition, wind farms receive an administered price for "spilling" onto the system, unlike other generators who would receive a less advantageous price for such an "unauthorised deviation". Therefore, with only 200 MW of current wind capacity, there is an issue at certain times, principally overnight, in that System Management needs to turn down or shut down plant, none of which wants to be shut down, but little of which is priced cost-reflectively. With the considerable increases in wind capacity likely to result from the expanded RET, this situation is likely to be significantly exacerbated.

Is this an issue for further consideration?

This is a material issue

Stakeholders commented that system operation was a major issue for Western Australia, and is likely to become a more significant issue as greater wind generation capacity is installed.[187]

Impact on the dispatch of scheduled generators

A particular issue in Western Australia is operating the system when wind plant generates a significant proportion of the supply. This is because other plant may need to be turned down to ensure system security and reliability. This is a dilemma for System Management as output from other plant may need to be reduced. The basis on which System Management makes these decisions may not be transparent.

This may already be an issue. Overnight load in the SWIS is only about 1000 MW and there is approximately 200 MW of wind generation connected to the system.[188] Wind generators will wish to generate whenever they can as their fuel costs are zero and they receive RECs for generating leading to negative short-run marginal costs.

Baseload conventional generators are also unwilling to shut down overnight as it can be technically difficult and potentially costly to do so and restart the next day, particularly given the age of much of the coal plant. To the extent that the sum of these generators' minimum stable export limits exceeds 800 MW, either wind farms or baseload generators will need to be shut down to match supply to demand.

However, even where overnight load is high enough on average to sustain coal-fired plant operated above minimum stable levels, System Management may decide to turn down or shut down coal-fired generators and start up more flexible gas turbines, in order to compensate for the volatility of output from the wind plant.

System Management has discretion to intervene in wind power dispatch to manage dispatch while maintaining power system security and reliability under chapters 3 and 7 of the WEM Rules. If wind is backed off by System Management in balancing,

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187 Western Power, p.2; Synergy, p.9.
188 Frontier 2008 WA and NT Market Implications paper, pp.45-46.

the plant is paid for its foregone output based on its pay-as-bid price.[189] However, it is understood that System Management will focus on reducing wind output if it considers that security would be jeopardised by turning down conventional generation.[190]

In its report to the AEMC, Frontier Economics identified "a need for a more transparent process governing how System Management intervenes in merit order dispatch to turn down both wind and conventional generation for system security reasons",[191] and stakeholders agreed that this issue needed to be addressed.[192]

Impact on balancing

In the WEM, System Management's primary tool for system balancing is to instruct Verve Energy to alter its scheduled output. Verve Energy will be paid the Marginal Cost Administrative Price (MCAP – an administered price based on the STEM price) if it is required to increase its generation above its scheduled position, and has to pay MCAP if required to generate less than scheduled. For instructed balancing deviations, generators other than Verve Energy are settled on a pay-as-bid basis.

By contrast, unauthorised deviations are settled by generators:

- receiving the Upward Deviation Price (UDAP), which is lower than MCAP, for any excess output; or
- paying the Downward Deviation Price (DDAP), which is higher than MCAP, to cover any insufficient output.

The exception is wind generation, which is permitted to "spill" onto the system, and receive MCAP.

Therefore, Verve Energy would receive no additional compensation if System Management decides to shut down inflexible coal-fired plant and start (more expensive) flexible gas turbines overnight to cope with the variability of wind generation. Equally, if wind energy displaces conventional generation, Verve Energy is effectively required to pay MCAP for the output of these plants.

As MCAP may be significantly greater than Verve Energy's costs of generating, it is quite possible that these arrangements may result in inefficient dispatch. The connection of additional wind generation to the SWIS is likely to further increase Verve Energy's exposure to balancing and potentially further reduce efficiency.

Impact on ancillary services costs

An increase in intermittent generation due to the expanded RET could lead to an increased use of frequency and voltage-related ancillary services.

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189 IMO, Wholesale Electricity Market Design Summary, September 2006, p.55.
190 Frontier 2008 WA and NT Market Implications paper, p.47.
191 Frontier 2008 WA and NT Market Implications paper, p.48.
192 Western Power, pp.5-6; Synergy, p.12.

The required amount of load-following reserve is understood to have increased from about 30 MW to 60 MW[193] and will increase further as more wind plant connects to the SWIS. Western Power confirmed that "for current levels of almost 200 MW of wind capacity, around 60 MW of gas turbine capacity would be required for load following purposes", and that, in this role, gas plant "runs at very low efficiency and hence high cost".[194] The costs of these ancillary services are recovered from load and non-scheduled generation on a pro rata basis.[195] Wind plant may not pay for the additional frequency ancillary services costs they impose as the output of wind plants can be more variable and unpredictable than customer load. It has also been suggested that wind plant do not fully pay for the network voltage control ancillary services costs they impose, because these are recovered based on metered consumption.

Given this, we consider that it may be appropriate to review the charging regime for WEM ancillary services in relation to the costs imposed by the operation of intermittent plant. Western Power agreed that additional costs imposed by intermittent generation, "should be identified, appropriately attributed to causers and users and efficiently recovered".[196]

What are the possible mitigation options?

One potential approach to improving the efficiency of the balancing arrangements would be for the WEM to move to a competitive balancing regime. In such a regime, Verve Energy would be treated like any other generator in that any rescheduling of its output upwards or downwards would be settled on the basis of its pay-as-bid price. One stakeholder, Synergy, was of the view that allowing "all generators to offer balancing via incremental offers and decremental bids" would be "a more efficient approach".[197] However, Verve Energy has a significant share of the market, and the ERA, in considering this issue, has noted that, at this early stage of the market, "achieving a competitive balancing market would be difficult".[198]

In light of this issue, and in the absence of further structural reform on the generation side of the market, in its report to the AEMC, Frontier Economics suggested alternative approaches. It considered that the potential inefficiencies from balancing "could also be addressed to some degree through better control over the dispatch of wind generation and more cost-reflective recovery of load-following costs".[199] It also identified a need "to facilitate the more transparent turning down of wind plant dispatch where failing to do so could require conventional plant to shut down."[200]

Other potential alternative mitigating approaches were raised by Synergy, which suggested that more accurate information would better enable Verve Energy to plan

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193 Frontier 2008 WA and NT Market Implications paper, p.51.
194 Western Power, p.5.
195 IMO, Wholesale Electricity Market Design Summary, September 2006, p.23.
196 Western Power, p.5.
197 Synergy, p.11.
198 ERA, Discussion Paper: Annual Wholesale Electricity Market Report to the Minister for Energy, 5 June 2008, pp.26-27.
199 Frontier 2008 WA and NT Market Implications paper, p.49.
200 Ibid, p.48.

the starting and stopping of its plant, decreasing its operating costs. This could be achieved through moving gate closure closer to real time, which it considered "would allow retailers and generators to adjust their positions to reflect the implications of changed weather forecasts on generation capabilities."[201] Alternatively, it suggested that the introduction of centralised wind generation forecasts in the WEM would also improve the accuracy of information available.

201 Synergy, p.10.

Issue B5: Connecting new generators to energy networks

Chapter Summary

This chapter considers the connection of new generators to energy networks in Western Australia. The expanded RET will stimulate investment in wind generation capacity. This is likely to be clustered in certain geographic areas, and remote from consumers and the existing transmission network. We consider that the existing model of bilateral negotiation for new connection will be unlikely to cope with large extensions to remote areas. There is significant risk of unnecessary costs and delays.

Questions

B5.1 Do you agree that the connection of new generators to energy networks in Western Australia is a significant issue and therefore should be progressed further under this Review? If not, what are your reasons for reconsidering this position?

B5.2 Should incentives be provided for Western Power to ensure the timely delivery of connections, and, if so, how should risk be most appropriately shared under such a scheme?

B5.3 Could improvements be made to the queue management process in Western Australia which do not conflict with the non-discrimination provision in the Wholesale Market Objectives?

B5.4 In a Western Australian context, would any of the models identified in Chapter A5 ensure the more efficient delivery of network connection services?

B5.5 Are there any other potential models that we should consider to mitigate this issue?

What is the desired market outcome?

The desired market outcome is that the connection of new generation to energy networks in Western Australia is efficient and timely. To achieve this, the connection process needs to promote:

- the timely consideration of connection applications by Western Power, especially if there are a large volume of connection applications, or if there are multiple connection applications in the same area;
- efficient cost-reflective pricing for new connections, so that potential connecting parties are given efficient locational signals; and
- an efficient level of investment in connection assets and network infrastructure, including building network infrastructure connecting multiple parties at the same location at the same time ("clustering") and taking into account the potential for future connecting parties in the same area as existing generation plant.

One challenge in Western Australia is that it appears likely that a large number of wind plant will seek to connect to the network. The expanded RET is likely to lead to a great deal of investment in renewable plant, principally wind plant. Modelling has suggested that there will need to be approximately 8 000 MW of new renewable plant across Australia by 2020 to meet the target of 60 000 GWh of electricity generated by renewable plant. Western Australia has many areas with good wind resources, and can be considered to have a particularly "wind-friendly" regulatory regime, with wind farms receiving firm access rights to the transmission system and being paid an administered price for "spilling" on to it.

In this context we now consider whether the current energy market frameworks in Western Australia can deliver efficient and timely connection of the forecast levels of new generation.

Will the current energy market frameworks deliver?

Likely to require amendment

There are some fundamental elements of the existing energy market frameworks that are unlikely to deliver timely and efficient generation connections. This is because the current framework for connecting new generation in Western Australia is already stressed by the number of connection applications and it is likely to be further stressed by increasing numbers of wind plants seeking connection. The key points in this assessment are that:

- Western Power has already adopted a queuing policy to assess the volume of applications, and some developers have to wait up to 12 months before their application is considered;
- the "unconstrained" network planning approach requires complex assessments of connection applications and it can take up to 18 months for Western Power to assess the application and provide a network access offer; and
- under the bilateral negotiation framework, there is a high risk of inefficient network investment extending to regions in which different parties develop generation or are likely to develop generation.

The supporting reasoning for these conclusions is presented in the following sections.

Is this an issue for further consideration?

This is a material issue

Stakeholders considered that the planning approach and connection process were material problems for Western Australia, particularly under the expanded RET. It was considered that this is a key issue for further consideration.[202]

202 Western Power, p.2; Synergy, p.13.

Planning approach

The "unconstrained" planning approach employed in the SWIS has led Western Power to connect only new generators where and when the network can accommodate the full output of the connected generator(s). The merits, or otherwise, of an unconstrained model when compared to a constrained approach (such as that used in the NEM) are considered in chapter B6. However, by linking the provision of the "local" generation connection to the deeper reinforcement required to allow for unconstrained access to the shared network, the complexity, and therefore time required, for both the assessment of the application and the construction of the resulting network augmentation is greatly increased.

Under this unconstrained approach, Western Power undertakes a number of modelling steps, a cost assessment and, potentially, an approvals process before potentially making a network access offer. This can take up to 18 months. The unconstrained planning approach can also affect the cost of the new connection, and therefore potentially also the generator's locational decision, through the "deep" connection costs charged.

In its report to the AEMC, Frontier Economics noted that the unconstrained planning approach is responsible for "causing delays to the connection process".[203] Given the current linkage between the assessment of the shared network and the generation connection, we propose to give further consideration to this issue as part of a joint progression of Issues 5 and 6 with respect to Western Australia, and this clearly could impact upon the connection process.

Connection Process

There is already a high volume of connection applications in Western Australia.[204] This is likely to be exacerbated by applications from wind farms prompted by the expanded RET, particularly because wind generators are, on average, smaller than thermal generators: new wind generation projects in the SWIS tend to have capacities in the range 80-130 MW, compared to 250-400 MW for thermal power stations.[205] In addition, wind plants tend to have relatively low capacity factors (around 30 per cent).[206]

Western Power has already adopted a queuing policy to assess connection applications strictly in the order in which they are received. Western Power has informed a number of applicants that it cannot commence processing their applications at this stage, or cannot do so for 6 to 12 months.[207] There is already over 1 300 MW of wind capacity seeking connection to the SWIS.[208] With greater numbers of applications likely from wind generators, this issue is likely to intensify.

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203 Frontier 2008, WA and NT Market Implications paper, p. 51.

204 For example, the IMO has stated that 13 new generation projects are due to connect to the SWIS before October 2011. IMO, "Statement of Opportunities", July 2008, p.9.

205 IMO, Statement of Opportunities, July 2008, p.9.

206 ROAM 2008 Market Impacts paper, pp.33, 38.

207 ERA, Discussion Paper: Annual Wholesale Electricity Market Report to the Minister for Energy, 5 June 2008, pp.18-19

208 Synergy, p.9.

The Reserve Capacity Mechanism impacts the connection process. New generators are only entitled to be assigned capacity credits in the capacity market if they have a network access offer. Developers may therefore apply for access for generation projects in very early stages of development. This can result in a larger number of less developed access applications being assessed by Western Power, leading to a queue. International experience suggests that, once they have been established, queues become self-perpetuating, as developers submit a larger number of projects at an earlier stage of development in order to secure their position in the queue.

There is a further impact. A developer that has obtained a network access offer and has capacity credits contingent on their plant being connected to the network bear the risk of having to make reserve capacity refunds if Western Power fails to make an actual network connection by the start of the relevant capacity year.

Although the ERA understands that there has not yet been a situation in which the operation of a new facility has been delayed as a result of a delay in the delivery of a network connection,[209] Western Power noted that locations proposed for new renewable generation tend to be in areas that would require significant capacity upgrades.[210]

It therefore seems likely that there is an increased risk that Western Power will not be able to deliver all new connections in a timely manner as a result of the renewable generation applications triggered by the expanded RET and attracted by the good wind resource and benign regulatory regime. Relevant international experiences may be informative.[211]

Stakeholders further agreed that planning additional investment in the network will be difficult, due to uncertainty surrounding the scale and timing of new renewable investments, and that this could "lead to delays in identifying the need, and obtaining planning consents, for the construction of new or reinforced infrastructure."[212]

Another significant issue was the potential for inefficient network development resulting from the bilateral negotiation regime. Essentially the same two issues identified in the NEM are also present in the SWIS:

- multiple connections in the same place at the same time, with the difficulties in co-ordinating an efficient connection between multiple parties. This is because the first generation developer would have to pay all the costs of extending the network, and all subsequent generation developers use this network at lower cost; and

209 ERA, Discussion Paper: Annual Wholesale Electricity Market Report to the Minister for Energy, 5 June 2008, p.19.

210 Western Power, p.6.

211 In Great Britain, which also has a net pool and employs a similar unconstrained planning approach, the mandatory Renewables Obligation led to a rush of connection applications from wind farms at the periphery of, or remote from, the existing transmission system, and completion dates in many connection offers far in excess of developer's aspirations, often 10 or more years in the future.

212 Synergy, p.13.

- the difficulty in predetermining the optimal size of connection assets where additional new remote generation is likely but not ready at the time of the first connection application.

What are the possible mitigation options?

Co-ordination of multiple and potential future connections

Stakeholders in Western Australia recognised the above two issues of co-ordinating multiple connections, and suggested that "Western Power needs to have effective incentives to connect new generation and develop infrastructure at an early stage, ahead of firm commitments from generators."[213] Consideration would need to be given as to how the upfront investment by Western Power would be funded, and as to how risk would be shared.

In chapter A5 we set out four potential models that could address the issues in relation to network connections: an "open season" approach (Option 1); a connection "hub" approach (Option 2); and variants of the "hub" approach with different economic test and charging features (Options 3 and 4). These options are equally as applicable to the SWIS, and we therefore intend to also consider them in a Western Australian context.

Incentives for timely connections

Given the potential for Western Power to be unable to deliver network connections in line with developers' aspirations, and the likelihood that this risk will be exacerbated under an expanded RET, it may be appropriate to consider the provision of incentives to promote the timely delivery of network connections.

Western Power has previously identified that network connection delivery risk could be dealt with through the use of liquidated damages, but noted that, if an allowance in the customer's capital contribution were factored in to cover liquidated damages, any over-recovery of revenue from the customer would be taken off Western Power's allowable revenue resulting in a tariff decrease to other customers. Conversely, any under-recovery would be made up under the revenue cap resulting in other users picking up the shortfall via network tariffs.[214]

Any incentive scheme could therefore be designed around this mechanism, such that, if it failed to meet a pre-defined target, Western Power would have some exposure to the under-recovery, but equally, in the event it out-performed the target, would retain some of the over-recovery. Clearly, careful consideration would have to be given to the appropriate target under such a scheme, together with the factors sharing risk between Western Power and its customers, along with any caps and collars.

213 Synergy, p.13.

214 Western Power, Annual Wholesale Electricity Market Review: Submission to the Economic Regulation Authority, 18 July 2008, p.4.

Queue Management

A clear sign that the connection process in Western Australia is already under stress is the fact that a queuing process has been introduced. Currently, Western Power assesses applications in the order in which they are submitted.

Under the progression of Issues 5 and 6 for Western Australia, we intend to give consideration to potential methods of queue management. This could, for instance, give greater weight to the readiness of the project, or to its size or technology employed (i.e. whether or not it was renewable). However, international experience suggests that it can be difficult to formulate rules that do not also raise concerns with regards to undue discrimination between applicants, and we note that one of the Wholesale Market Objectives is to avoid discrimination against particular energy options and technologies.

Issue B6: Augmenting networks and managing congestion

Chapter Summary

This chapter considers network augmentation in Western Australia, and the ability of the existing frameworks to promote efficient use of and investment in the network. In the SWIS, the inability to resolve congestion in a cost-reflective manner, and therefore evaluate the costs of this against network augmentation, can result in inefficient over-investment in the transmission network and consequent delays to the connection of new generators. The expanded RET is likely to exacerbate this situation by leading to a significant amount of renewable generation wishing to connect to the system at the periphery of the transmission network with low capacity factors.

Questions

B6.1 Do you agree that network augmentation in Western Australia is a significant issue that should be further progressed under this Review? If not, what are your reasons for reconsidering this position?

B6.2 Would any of the options identified in this chapter improve the efficiency of network augmentation in the SWIS? In particular, we would welcome views on:

- the practicality of including an evaluation of congestion costs in planning network augmentations;
- other assumptions made as part of the planning process (such as the capacity factor of wind generation); and
- the most appropriate locational signals for generation in the SWIS.

B6.3 Are there any other potential models that we should consider to mitigate this issue?

What is the desired market outcome?

The desired market outcome is for energy market frameworks to promote efficient use of and investment in the network. Market signals provide incentives to participants, such as generation and network businesses, and new investors, in both generation plant and merchant transmission, about how to use and invest in the network's capability to transport energy. End use customers, as the principal beneficiaries of the network, should pay transmission charges that reflect the shared network used to transport their energy.

The decisions participants make about how they use and invest in the network are decentralised under the current regime. The regulated network business in the SWIS will respond to network issues that arise from generation plant and customer (load) consumption and location decisions. The existing energy market framework signals relevant to this discussion include:

- **Generation locational signals:** costs of connection and extension assets; transmission access; transmission loss factors; and availability of fuel.

- **Network signals:** planning arrangements and responsibilities; operations; and charging arrangements.

These signals become increasingly important under the CPRS and the expanded RET. In Western Australia, the main effect of these policies is likely to be a substantial increase in wind plant and back up gas generation connecting to the network. The prevailing power flows across the network will therefore depend on the locational decisions of this new generation.

The transmission network in the SWIS is planned on an "unconstrained" basis, which means that Western Power will only connect new generation if the prevalence of network congestion is not increased or else will undertake network upgrades prior to the connection of the generation to maintain the "unconstrained" nature of the network. The amount of network augmentation required is therefore determined by the location of the connecting generation, and this augmentation is delivered at the same time as the generation connection in a co-ordinated manner.

We therefore consider whether, in light of the climate change policies, the existing framework signals can deliver efficient use of and investment in the network.

Will the current energy market frameworks deliver?

Framework is not sufficiently flexible

The current arrangements for augmenting the shared network in Western Australia are not sufficiently flexible to deliver the desired market outcome in light of the climate change policies. This is because of:

- the inability to resolve congestion in a cost-reflective manner and therefore evaluate the costs of this against network augmentation, which can result in inefficient over-investment in the transmission network and consequent delays to the connection of new generators; and

- the fact that the situation will be exacerbated by the significant amount of renewable generation wishing to connect to the system as a result of the climate change policies, which is likely to be at the periphery of the transmission network and have low capacity factors.

We discuss the reasoning behind these conclusions in the next section.

Is this an issue for further consideration?

This is a material issue

Planning approach

As noted in chapter B5, Western Power employs an "unconstrained" approach to network planning. The precise meaning of this term is not defined in any published documents. However, based on correspondence between Western Power staff and

Frontier Economics, it derives from the requirement in the Technical Rules for Western Power to plan, design and construct its power system to ensure that power system stability and performance can be met under the worst credible load and generation patterns and the most critical credible contingency events, without exceeding any component ratings or the allocated power transfer capacity.[215] This, in turn, has led Western Power to connect only new generators where and when the network can accommodate the full output of the connected generator(s). This contrasts with the approach employed in the NEM, but to a large extent this difference is reflective of the contrasting characteristics and development of the two markets.

The NEM is a "gross pool", into which eligible generators are required to offer their output. NEMMCO dispatches the market every five minutes with the objective of minimising the cost of dispatch based on bids and offers from generators and larger load customers. Generators consequently face the risk that they might not be dispatched for their desired output. A generator's "right" to use the transmission network therefore depends on whether it is dispatched by NEMMCO or not. This is termed an "open access" regime. Importantly, if congestion is present on the transmission network, a generator may not be dispatched, even if its offer price is below the RRP that would be paid for supply. Therefore, under the "constrained" network planning approach used in the NEM, a generator may be connected to the network even though the transfer capability of the shared network may be insufficient to ensure that it is dispatched when its offer price is below RRP.

The WEM is a "net pool", where the majority of electricity is traded through bilateral contracts. Generators are self dispatched by making a Bilateral Submission to the IMO. All Bilateral Submissions must be balanced, in the sense that the total energy to be supplied to the network by the generator must match the total energy forecast to be taken from the network by customers who are counterparties to the generator. To the extent that supply does not match demand in real time, System Management is able to schedule Verve Energy plant, and, if necessary, issue dispatch instructions to other market participants, to balance the system. In this market, therefore, generators have a firm right to export onto the system to the level of their desired output.

However, the unconstrained planning approach can lead to inefficient over-investment in the transmission network, as it may be more efficient to allow some congestion to occur than to augment the network (i.e. if the costs of managing the congestion were less than the cost of augmenting the network). In its report to the AEMC, Frontier Economics concluded that "there is little doubt that the unconstrained planning approach leads to inefficient over-investment".[216] In a market with firm access rights it is possible to permit an efficient level of congestion by compensating parties required to reduce output. In Western Australia there is, however, currently no market mechanism to allow for the management of constraints in a cost-reflective manner.

In its submission to the AEMC 2008 Scoping Paper, Western Power suggested that some savings could be made over the current approach, in particular "by assuming that intermittent generators and scheduled generators are not simultaneously operating at full output". However, it further noted that:

215 Frontier 2008 WA and NT Market Implications paper, p.9.
216 Frontier 2008 WA and NT Market Implications paper, p.51.

> this would involve the development and management of network constraints, which would require a market mechanism to determine which generator runs if both intermittent and scheduled generators were available.[217]

Given that the average capacity factor of wind generation is typically around 30%, and that wind generators very rarely operate at full output, it seems likely that there is significant scope for reviewing the appropriateness of these assumptions. The other stakeholder to address this issue in a specifically Western Australian context, Synergy, also commented on the "current requirement for 100% coverage of generation capacity… even when the plant is intermittent and will not require that network capacity all of the time". Synergy noted that there are therefore "no clear rules for sharing network access where capacity is constrained" and advocated the consideration of network access sharing arrangements.[218]

We consider that there is a need to review the unconstrained planning approach employed, and the assumptions used in planning, particularly in light of the likely entry of significant amounts of low capacity factor renewable plant under the expanded RET.

Locational signals

It is important to have market signals that promote efficient locational decisions for these significant levels of new generation forecast under the climate change policies. This is especially the case where the shared network is being reinforced on an unconstrained basis. Although it is important that the costs of network augmentation are efficiently balanced against the likely costs of congestion, it is even more important that these costs are signalled to the new generator to be taken account of in the decision as to where to locate. Some of the factors influencing generation location decisions include: the availability of fuel; the cost of connection and extension assets (see chapter B5); and transmission loss factors.

It was suggested by a stakeholder that further locational signals, over and above these, are required in the WEM. Synergy expressed concern:

> that economic efficiency in the design and construction of the electricity transmission system may not occur until the WEM and the network both send localised price signals to asset owners, which incentivise them to construct at the point where the network and the electricity market most require the generation.[219]

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217 Western Power, p.6.
218 Synergy, p.15.
219 Synergy, p.14.

However, this stakeholder also believed that the recalculation of loss factors, the downwards adjustment of the gross volume produced by the generator to reflect the proportion of energy lost (e.g. as heat) in the transmission network, represented a material risk. Synergy commented that an:

> ability to lock in a loss factor at the time of investment is required to ensure adequate stability in the investment environment. Currently any project located in a network area with an attractive loss factor, is likely to have another project locate nearby soon afterwards. Investment by a second plant is likely to drive down the loss factor significantly, eroding any benefits factored in by the first project in their viability assessment.[220]

We therefore consider that there is a need to review the locational signals present in the SWIS in parallel with a reassessment of the planning approach employed, to ensure that the locational decision, as well as the network response to this in terms of the resulting amount of network augmentation, is fully efficient.

What are the possible mitigation options?

Revised planning approach, including an evaluation of congestion costs

Given that, in some cases, it may be more efficient to allow congestion to occur than to augment the network, it should be possible to move to a more efficient planning approach which includes an evaluation of congestion costs. However, this would first require the introduction of a market mechanism to allow for the management of constraints in a cost-reflective manner, and there would be significant difficulties and costs in implementing such an approach. In correspondence with Frontier Economics, Western Power noted that this would require:

- development, management and implementation of constraint equations by System Management; and
- review of the role and functioning of the Reserve Capacity Mechanism, as the IMO could not be confident that all capacity that is accredited would be able to meet load at peak times.[221]

There also appears to be scope for reviewing the assumptions made in the network planning process relating to the output of generators, and these could be specified in a more explicitly defined set of planning standards. This could reduce the amount of incremental network capacity required to connect additional wind generation, thereby facilitating the connection of additional renewable generation in a more efficient and timely manner.

The introduction of a more formal congestion management regime in the SWIS could therefore facilitate the sharing of access, as well as allowing for network investment to be avoided if the cost of doing so was greater than the costs of resolving any resulting congestion. This would potentially allow some connections to progress more quickly, and would produce savings for consumers overall (i.e. congestion management related

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220 Synergy, p.15.

charges would be less than the amount by which investment related charges would have increased). However, implementation costs are likely to be significant.

A further step that could be considered would be to de-link the provision of the "local" generation connection from the reinforcement of the shared network (even if this reinforcement was more cost-effective than resolving the resulting congestion). Under this model, the generator would be permitted to generate as soon as the local connection was complete, irrespective on the status of the deeper reinforcement. The resulting congestion costs could either be socialised or targeted cost-reflectively at the generator causing them (although this would likely be a non-trivial exercise). This model would allow for the most rapid connection of generators, but may prove unattractive due to resulting costs.

Locational signals

To mitigate the lack of locational signals in WEM, a stakeholder suggested that there would be merit in assessing "the appropriateness of establishing zonal pricing in the WEM."[222] It is not clear how a zonal pricing model would be consistent with the current WEM net pool arrangements in which nearly 95 per cent of electricity is traded bilaterally.[223] However, it would be possible for locational signals to be given through transmission pricing, for instance through locational generation TUOS charges reflective of the costs of reinforcing the system.

As a further development, a model in which generators paid either a locational short run marginal cost derived charge based on congestion costs caused or a locational long run marginal cost derived charge based on investment costs undertaken to provide firm access would approximate a Locational Marginal Price type market with Financial Transmission Rights.

221 Frontier 2008 WA and NT Market Implications paper, p.51.
222 Synergy, p.14.
223 IMO, Wholesale Electricity Market: Electricity Trading 2006/07, July 2007, pp.16-17.

Issue B7: Retailing

Chapter Summary

This chapter considers energy retailing in Western Australia. The existing jurisdictional price regulation arrangements are not sufficiently flexible or adequate to enable retailers to manage and recover costs, and this situation will be exacerbated by the large cost increases related to the CPRS and expanded RET. While there are existing processes investigating potential changes to address this issue, there is a risk of the recommended changes being implemented too late. This is therefore a material problem.

Questions

B7.1 Do you agree that the current inflexibility in the retail price regulatory arrangements in Western Australia is a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position?

B7. 2 How can further work undertaken in this Review be best incorporated with the Office of Energy's ongoing Electricity Retail Market Review?

What is the desired market outcome?

The desired market outcome is for the energy market frameworks to promote and support healthy competitive retail markets that deliver efficient prices and services to energy customers. Where competition is not effective or possible, the desired market outcome is for retail price regulation to provide a framework for determining regulated customer tariffs that are cost-reflective and sufficiently flexible to respond to large changes in costs that are beyond a retailer's control. To the extent that retailers do exit the energy markets, a "safety net" mechanism should be in place to protect customers should those exits be quick or unexpected.

In Western Australia, the former Government's energy policy objective was to "implement appropriate market and regulatory arrangements to achieve a competitive, dynamic and sustainable energy sector"[224]. To implement this policy, the Government disaggregated the vertically integrated State-owned generation, network and retail business into three separate parts. It also established the WEM.

Western Australia has yet to introduce Full Retail Contestability (FRC). Retail competition is therefore limited to customers that consume more than 50 MWh per annum. This means that only around 15 000 customers, or 1.5 per cent of total customers in Western Australia, are contestable.[225] However, because these customers

224 Office of Energy, Electricity Retail Market Review: Draft Recommendations Report, April 2008, p.7.
225 ERA, 2006/07 Annual Performance Report: Electricity Retailers, January 2008, p.10.

are large users of electricity, they may represent up to 60 per cent of total energy consumption.[226]

Given the early stage in the development of retail competition in Western Australia, there are regulated tariffs for all customer groups. The State-owned host retailer, Synergy, supplies electricity to all non-contestable customers in the SWIS (i.e. those consuming less than 50 MWh).

A retailer's own costs are a very small proportion of its total costs. The bulk of its costs represent the costs of buying wholesale energy, including prudential obligations, and network charges, which an individual retailer has only limited control over. The CPRS and expanded RET are likely to affect wholesale energy costs, which highlights the importance of flexible retail tariffs.

If retail tariffs are not flexible and are set below costs, retailing electricity may not be a profitable business activity, inhibiting new entry and causing the exit of existing retailers. Where there is no competition and market exit is not possible, the only retailer (normally State-owned) will face substantial financial losses. To minimise these financial losses, the retailer may cross-subsidise between different customer classes. Customers will also have inefficient incentives around their consumption levels because the price for electricity does not reflect its true value.

We consider in this chapter whether the energy market frameworks for retailing in Western Australia are able to accommodate these changes in light of the ongoing reform process in the retail market in that jurisdiction.

Will the current energy market frameworks deliver?

Framework is not sufficiently flexible

The current market frameworks will not deliver efficient prices and services to retail customers in Western Australia following the introduction of the CPRS and expanded RET.

- Electricity retailing is already a major issue in Western Australia. Contestability has yet to be introduced for the majority of customers, and regulated retail tariffs are not cost reflective. Further, there is no regulated process for regular tariff reviews.

- The CPRS and the expanded RET will further exacerbate the situation, given the lack of flexibility for retailers to manage and recover the cost increases that will result from these climate change policies.

This is therefore a material problem and warrants further consideration in this Review and in conjunction with relevant Western Australian market institutions. The reasoning for these conclusions and possible mitigation options are presented in the following sections.

226 Ibid., p.10.

Is this an issue for further consideration?

This is a material issue

Cost-reflective regulated retail tariffs

In Western Australia, electricity retail tariffs are regulated by the Minister for Energy.[227] These tariffs have been frozen for some time, and are generally recognised as being far below cost reflective levels. Residential tariffs have not increased since 1997-1998 (excluding the introduction of GST in 2000-2001), reflecting a real price reduction to 2009-2010 of about 30 per cent. Small business tariffs have not increased since 1991-1992, translating to a real price reduction of about 38 per cent to 2009-2010, and large business tariffs were unchanged between 1991-1992 and July 2007.

Under its Electricity Retail Market Review, the Office of Energy has recommended that, to return retail tariffs to cost-reflective level, residential tariffs should increase by 47 per cent in 2009-2010, and tariffs for other small use customers should increase by between 21 per cent and 44 per cent.[228] The Office of Energy additionally forecast that tariffs would require a further increase of 15 per cent in 2010-2011. Of this further 15 per cent increase, 11 percentage points represents an indicative estimate for the cost increase associated with the introduction of the CPRS.[229]

The former Western Australian Government rejected the Office of Energy's recommendation, instead opting for a 10 per cent increase for residential customers in 2009-2010, with further annual increases to be phased in over a six to eight-year period.[230] The new Government has yet to make any further announcement on this issue.

Tariff review process

Western Australia does not currently have a process for periodic tariff reviews.

As part of the recommendations of its Electricity Market Retail Review, the Office of Energy therefore also proposed that, to give greater certainty to investors and consumers, a regulated process for regular tariff reviews should be implemented.

It was proposed that tariffs should be regularly reviewed by the ERA as an independent regulatory authority, and that the ERA would be responsible for the final determination of the tariffs. Tariffs would be reviewed on at least a triennial basis, with annual adjustments made, based on parameters the ERA determined at each periodic tariff reset.[231]

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227 The regulated retail tariffs in the SWIS are specified in the Energy Operators (Electricity Retail Corporation) (Charges) By-laws 2006.

228 Office of Energy, Draft Recommendations Report – Electricity Tariff Arrangements, April 2008, pp.3-7.

229 Ibid., p.10.

230 See: http://www.mediastatements.wa.gov.au/ArchivedStatements/Pages/CarpenterLaborGovernmentSearh.aspx?ItemId=129961&minister=Carpenter&admin=Carpenter

231 Office of Energy, Draft Recommendations Report – Electricity Tariff Arrangements, April 2008, pp.28-

The decision by the previous government to reject the recommendation to increase tariffs to cost-reflective levels in 2009-2010, and instead, phase these in over six to eight years, could be taken as evidence that it was their intention to retain responsibility for determining tariffs for at least this transitionary period. The position of the new Government is not clear.

To the extent that regulated tariffs remain non cost-reflective, the introduction of the CPRS and the expanded RET are likely to exacerbate the existing issues facing the market. While retailers are unable to recover the additional costs resulting from the introduction of these policies, State-owned participants unable to exit the market will make even greater losses, inefficient cross-subsidies will intensify, and retail entry into Western Australia will continue to be highly unattractive.[232]

Retailer of Last Resort

Given the competitive situation in Western Australia, there is unlikely to be the exit of a retailer with any significant numbers of customers. The potential robustness of the RoLR processes is therefore of much less consequence in Western Australia than in other jurisdictions.

What processes are investigating potential changes to address the issues?

Office of Energy Reform Process

As discussed above, the Office of Energy has recommended that regulated retail tariffs be returned to cost reflectivity and that a regulated process for regular tariff reviews be introduced.[233] These would, in any case, be important steps to prevent the State-owned retailer from experiencing further financial losses[234] and to remove any inefficient cross-subsidies. Cost-reflective tariffs would also provide more efficient consumption incentives for customers. These improvements are also essential pre-requisites for the introduction of further competition.

However, such reforms would also potentially provide a framework for the cost-reflective pass-through of the additional costs that retailers will incur under the CPRS and expanded RET. The proposal that the ERA would be required to annually adjust retail tariffs based on parameters that it determines at each periodic tariff reset may provide the flexibility required to pass-through the likely varying costs of the CPRS and expanded RET, whilst still providing price transparency and stability.

Under its Electricity Retail Market Review, the Office of Energy is due to consider the potential introduction of FRC.[235] Subject to the development of effective competition and the removal of retail tariff regulation, this would allow retailers to competitively set prices, reflective of all costs, and revise them in a fully flexible manner. However,

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232 Synergy, p.16.

233 Office of Energy, Draft Recommendations Report – Electricity Tariff Arrangements, April 2008.

234 Under the Vesting Contract between Synergy and Verve Energy, these losses are essentially passed through to Verve Energy.

235 Office of Energy, Electricity Retail Market Review: Issues Paper, December 2007.

given the existing position in Western Australia this is unlikely to be implemented in the short-term.

In addition, the MCE commented on the importance of flexibility in its December 2008 meeting, noting that carbon-cost pass-through in retail energy markets was important to the function of the CPRS. At that meeting, Ministers agreed to propose to COAG that it amend the AEMA to specify that, where retail prices were regulated, energy cost increases associated with the CPRS shall be passed through to end-use consumers.[236] However, noting that the recommendation was only announced on 12 December 2008, a work program to implement this policy position remains to be established and progressed.

236 Ministerial Council on Energy, 17 Meeting Communiqué, December 2008, Adelaide, p.2.

PART C: Issues for the Review – Northern Territory

Introduction

This Part provides our analysis of seven of the eight issues identified in the Scoping paper for the Northern Territory. (We consider Issue 8 to be broader than any specific market, and this is therefore covered by chapter A8.) The Northern Territory, whilst a signatory to the overarching Australian Energy Market Agreement, independently operates its own electricity and gas markets. The gas transmission and distribution market is regulated by the AER.

The CPRS and expanded RET will have unique effects on the Northern Territory energy market frameworks compared with Western Australia and the NEM. As a consequence Issues C1-6 are covered jointly in this Review for the Northern Territory as they do not impact materially on the Northern Territory energy market frameworks. Issue C7 is covered separately as it has material implications.

Overview of energy markets in the Northern Territory

The Northern Territory's electricity market is comprised of three separate relatively small regulated systems, the largest of which is the Darwin to Katherine system. Over 99 per cent of electricity in the Northern Territory's regulated systems is generated using gas-fired plant.[237]

The Northern Territory has virtually no coal deposits, and, due to a lack of climatic suitability, has virtually no resources for wind generation or other large-scale renewable generation technologies (although photovoltaic and thermal solar generation is used on a small scale in remote regions).

There are three key gas reserves: the Amadeus, Browse and Bonaparte basins, and LNG is exported from the Bonaparte basin. Roughly 90 per cent of natural gas in the Territory is used for electricity generation, with most of the remaining 10 per cent being reticulated to commercial and industrial customers in Alice Springs and Darwin.

Interaction with other initiatives

Regulation of the Northern Territory's electricity supply and electricity network industries is the responsibility of the Utilities Commission. The Utilities Commission's broad mandate is to ensure the promotion and safeguard of competition and fair and efficient market conduct. In the absence of a competitive market, the Utilities Commission's primary role is to stimulate the conditions of competitive conduct by preventing the misuse of monopoly power in the regulated markets for which it is responsible.

237 Utilities Commission, Annual Power System Review, December 2007, p.25.

Issues C1-C6: Northern Territory

Chapter Summary

This chapter examines the effects that the introduction of the CPRS and expanded RET will have on the Northern Territory's energy market frameworks in respect of:

- the convergence of gas and electricity markets;
- generation capacity in the short-term;
- investing to meet reliability standards with increased use of renewables;
- system operation and intermittent generation;
- connecting new generators to energy networks; and
- augmenting networks and managing congestion.

There will be a limited impact in the Northern Territory in relation to these issues due to the Territory's current and future likely reliance on gas generation.

Questions

C1.1 Do you agree that the convergence of gas and electricity markets in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

C2.1 Do you agree that generation capacity in the short-term in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

C3.1 Do you agree that investing to meet reliability standards with increased use of renewables in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

C4.1 Do you agree that system operation and intermittent generation in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

C5.1 Do you agree that connecting new generators to energy networks in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

C6.1 Do you agree that augmenting networks and managing congestion in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

What affect will the CPRS and expanded RET have?

The introduction of the CPRS and expanded RET for the most part will have a limited effect on the Northern Territory's energy market frameworks. This is because there is unlikely to be fuel-switching in the Northern Territory as:

- gas-fired generation accounts for 99 per cent of the energy in the Northern Territory's regulated systems as there are no significant coal deposits;[238] and
- there are virtually no wind generation sites due to a lack of climatic suitability. However, solar generation is used on a small scale in remote areas.[239]

In the Northern Territory, the CPRS and expanded RET are likely to lead to higher wholesale electricity prices and higher retail costs.

- Wholesale electricity prices are likely to increase because gas-fired generation will need to purchase carbon permits to cover their emissions. This will increase the fuel cost for these generators.
- Retail costs are also likely to increase due to higher wholesale electricity prices and requirements under the expanded RET to purchase RECs.

Will the current energy market frameworks deliver?

Issue C1 – Convergence of gas and electricity markets

Current energy market framework is robust

The dominant fuel for electricity generation in the Northern Territory is gas. Also roughly 90 per cent of natural gas in the Northern Territory is used for electricity generation.[240] Given that there is already a high interdependence between the gas and electricity markets in the Northern Territory and that there will not be fuel switching, the introduction of the CPRS and expanded RET will not have a significant impact on the current arrangements.

Issue C2 – Generation capacity in the short term

Current energy market framework is robust

There is no evidence to suggest that the uncertainty around climate change policies has delayed generation investment decisions in the Northern Territory. As such, the introduction of the CPRS and expanded RET is unlikely to adversely affect the reliability of electricity supply in the short-term.

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238 Utilities Commission, Annual Power System Review, December 2007, p.25.
239 Frontier 2008 WA and NT Market Implications paper, p.109.
240 Ibid., p.112.

Issue C3 – Investing to meet reliability standards with increased use of renewables

Current energy market framework is robust

Due to the lack of potential sites to facilitate wind generation in the Northern Territory, the introduction of the CPRS and expanded national RET is unlikely to create any problems associated with this issue in the Northern Territory energy market frameworks.

Issue C4 – System operation and intermittent generation

Current energy market framework is robust

The CPRS and expanded RET are unlikely to affect system operation in the Northern Territory. The lack of potential wind generation sites means the Northern Territory will not experience the same issues around managing intermittent generation as the NEM and Western Australia.

Issue C5 – Connecting new generators to energy networks

Current energy market framework is robust

The CPRS and expanded RET are unlikely to lead to an increase in new renewable generation locating in the Northern Territory due to the lack of potential renewable sites. As such, the current bilaterally negotiated connection agreement model is unlikely to be tested. In this regard it appears that the current arrangements will be able to support the introduction of the CPRS and expanded RET.

Issue C6 – Augmenting networks and managing congestion

Current energy market framework is robust

The introduction of the CPRS and expanded RET are unlikely to increase the current levels of congestion and requirement for augmentation. This is because there is unlikely to be any new generation locating in the Northern Territory and there will not be any change in the dispatch merit order as 99 per cent of generation is gas-fired. The current arrangements are therefore sufficiently robust to withstand the introduction of the CPRS and expanded RET.

Issue C7: Retailing

Chapter Summary

This chapter considers the jurisdictional price regulation arrangements for electricity retailing in the Northern Territory. It is uncertain whether these arrangements are sufficiently flexible or adequate to enable retailers to manage and recover the large costs increases related to the CPRS and expanded RET, as this is dependent on whether tariffs specified in Electricity Pricing Orders are set at a cost-reflective levels. This, therefore, may be a material problem and warrants further consideration in this Review.

Questions

C7.1 Do you agree that the retail price regulatory arrangements in the Northern Territory may be a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position?

What is the desired market outcome?

The desired market outcome is for energy market frameworks to promote and support healthy competitive retail markets that deliver efficient prices and services to energy customers. Where competition is not effective or possible, the desired market outcome is for retail price regulation to provide a framework for determining regulated customer tariffs that are cost-reflective and sufficiently flexible to respond to large changes in costs that are beyond a retailer's control. To the extent that retailers do exit the energy markets, a "safety net" mechanism should be in place to protect customers should those exits be quick or unexpected.

In general, a retailer's own costs are a very small proportion of its total costs. The bulk of its costs represent the costs of buying wholesale energy, including prudential obligations, and network charges, which an individual retailer has only limited control over. Under the CPRS and expanded RET, the strong reliance on gas-fired generation coupled with the lack of viable low-emission alternatives means the Northern Territory is exposed to increasing wholesale generation costs. This is particularly the case as the cost of carbon increases. The Northern Territory is also relatively exposed to the REC price as it may not be able to source sufficient credits locally. This highlights the importance of flexible retail tariffs.

If retail tariffs are not flexible and are set below costs, retailing electricity may not be a profitable business activity, inhibiting new entry and causing the exit of existing retailers. Where there is no competition and market exit is not possible, the only (state-owned) retailer will face substantial losses. The retailer may, where possible, cross-subsidise between different customer classes. Customers will also have inefficient incentives around their consumption levels because the price for electricity does not reflect its true value.

Currently, the Power and Water Corporation (PWC) is the only retail provider in the Northern Territory. While electricity contestability is limited to customers with a consumption over 750 MWh per annum, in practice, large industrial and businesses consumers must accept the contract terms offered by PWC, or less often, generate their own electricity. Large consumers can have the Utilities Commission review their contract terms to determine if the price and service standards are fair and reasonable.[241]

Non-contestable retail tariffs and charges are regulated by the Government, via an Electricity Pricing Order issued by the Regulatory Minister.

We consider in this chapter whether the energy market frameworks for retailing in the Northern Territory are able to accommodate these changes in light of the ongoing reform process in the retail market in that jurisdiction.

Will the current energy market frameworks deliver?

Framework may not be sufficiently flexible

It is uncertain whether or not the current market frameworks will deliver efficient prices and services to retail customers in the Northern Territory following the introduction of the CPRS and the expanded RET.

Whether the process for setting non-contestable retail tariffs can deliver efficient prices depends on whether the new Electricity Pricing Order sets tariffs at a cost-reflective level, in light of the increased costs relating to the CPRS and expanded RET.

Therefore, this may be a material problem and warrants further consideration in this Review. The reasoning for these conclusions are presented in the following sections.

Is this an issue for further consideration?

This is a material issue

Cost-reflective regulated retail tariffs

The increased costs incurred under the CPRS and the expanded RET will need to be recovered by PWC. The current Electricity Pricing Order expires on 30 June 2009. The materiality of this issue depends on whether the new Electricity Pricing Order will set cost-reflective tariffs that account for the increased costs related to the CPRS and expanded RET. This is important in light of the Northern Territory Government's scheduled introduction of FRC by April 2010.[242] New entry into the Northern Territory retail market will be less attractive if the new entrants are unable to compete effectively because they cannot recover their costs.

241 Northern Territory Treasury.

242 AER, State of the Market Report 2008, 20 November 2008, Melbourne, p.215.

We have therefore concluded that this issue warrants further consideration alongside the arrangements in the Northern Territory to ensure that, where regulated retail tariffs remain in place, the process for determining them can adequately allow for the increased costs that are likely to result from the climate change policies.

In addition, the MCE commented on the importance of flexibility in its December 2008 meeting, noting that carbon-cost pass-through in retail energy markets was important to the function of the CPRS. At that meeting, Ministers agreed to propose to COAG that it amend the AEMA to specify that, where retail prices were regulated, energy cost increases associated with the CPRS shall be passed through to end-use consumers.[243] However, noting that the recommendation was only announced on 12 December 2008, a work program to implement this policy position remains to be established and progressed.

Retailer of Last Resort

Given the competitive situation in the Northern Territory, it is unlikely that the monopoly Government-owned retailer will exit the market. The potential robustness or the RoLR processes is therefore of much less consequence in the Northern Territory than in the NEM.

243 Ministerial Council on Energy, 17 Meeting Communiqué, December 2008, Adelaide, p.2.

APPENDIX A: GLOSSARY

ACQ	Annual Contract Quantity
AEMA	Australian Energy Market Agreement
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APIA	Australian Pipeline Industry Association
AWEFS	Australian Wind Energy Forecasting System
BB	Bulletin Board
CCS	Carbon Capture and Storage
CMR	Congestion Management Review
COAG	Council of Australian Governments
CPRS	Carbon Pollution Reduction Scheme
CRR	Comprehensive Reliability Review
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DDAP	Downward Deviation Price
DSP	Demand Side Participation
ESCOSA	Essential Services Commission of South Australia
ESIPC	Electricity Supply Industry Planning Council of South Australia
ENA	Energy Networks Association
ERA	Economic Regulation Authority
ERAA	Energy Retailers Association of Australia
ESAA	Energy Supply Association of Australia
ESAS	Electricity Sector Adjustment Scheme
EUAA	Energy Users Association of Australia

Expanded RET	Expanded national Renewable Energy Target
FCAS	Frequency Control Ancillary Services
FRC	Full Retail Competition
GJ	Gigajoule
GSOO	Gas Statement of Opportunities
GW	Gigawatt
GWh	Gigawatt hour
IMO	Independent Market Operator
LNG	Liquefied Natural Gas
LRPP	Last Resort Planning Power
MCAP	Marginal Cost Administrative Price
MCE	Ministerial Council on Energy
MCMPR/MCE JWG	Ministerial Council on Mineral and Petroleum Resources/ Ministerial Council on Energy Joint Working Group
MDQ	Maximum Daily Quantity
MEU	Major Energy Users
MHQ	Maximum Hourly Quantity
MMA	McLennan Magasanik Associates
MMS	Market Management System
MPL	Maximum Price Level
MT PASA	Medium term Projected Assessment of System Adequacy
MW	Megawatt
MWh	Megawatt hour
NCAS	Network Control Ancillary Service
NCC	National Competition Council
NEL	National Electricity Law
NEM	National Electricity Market

NEMMCO	National Electricity Market Management Company
NEO	National Electricity Objective
NER	National Electricity Rules
NERG	Network Extension for Remote Generation
NGF	National Generators Forum
NGL	National Gas Law
NGO	National Gas Objective
NGR	National Gas Rules
NSP	Network Service Provider
NTNDP	National Transmission Network Development Plan
NTP	National Transmission Planner
OCGT	Open Cycle Gas Turbine
OOE	Government of Western Australia Office of Energy
PASA	Projected Assessment of System Adequacy
PJ	Petajoule
PTS	Principle Transmission System
PWC	Power and Water Corporation
REC	Renewable Energy Certificate
RERT	Reliability and Emergency Reserve Trader
REWG	Renewable Energy Working Group
RIT-T	Regulatory Investment Test for Transmission
RoLR	Retailer of Last Resort
RRN	Regional Reference Node
RRP	Regional Reference Price
Rules	National Electricity Rules and National Gas Rules
SCGT	Simple Cycle Gas Turbine

SKM	Sinclair Knight Merz
SLF	Static Loss Factor
SOO	Statement of Opportunities
SRMC	Short Run Marginal Cost
STEM	Short Term Energy Market
STTM	Short Term Trading Market
SWIS	South West Interconnected System
TEC	Total Environment Centre
TNSP	Transmission Network Service Provider
TUOS	Transmission Use of System
UDAP	Upward Deviation Price
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital
WEM	Wholesale Electricity Market in Western Australia

APPENDIX B: LIST OF ISSUES AND QUESTIONS

NEM Issue	Questions
A1. Convergence of gas and electricity markets	Do you agree that the convergence of gas and electricity markets is not a significant issue in the eastern states and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
A2. Generation capacity in the short-term	Do you agree that the ability for NEMMCO to manage actual or anticipated transitory shortfalls of capacity is a significant issue that should be progressed further under this Review? Are additional mechanisms required to complement the Reliability and Emergency Reserve Trader (RERT) and NEMMCO's directions powers, and what characteristics should such mechanisms have? Do you have any views on the detailed design and implementation of additional mechanisms?
A3. Investing to meet reliability standards with increased use of renewables	Do you agree that the existing framework based on an energy-only market design with supporting financial contracting is capable of delivering efficient and timely new investment, including fast response capacity to manage fluctuations in outputs resulting from larger volumes of intermittent wind generation? If not, what are your reasons for reconsidering this position? Do you agree that the processes supporting the ongoing maintenance of this framework in respect of review and periodic amendment to the market settings, including the maximum market price, are robust? If not, what are your reasons for reconsidering this position?
A4. System operation and intermittent generation	Do you agree that operation of the power system with increased intermittent generation is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
A5. Connecting new generators to energy networks	Do you agree that the connection of new generators to energy networks is a significant issue that should be further progressed under this Review? If not, what are your reasons for reconsidering this position? Would any of the models identified in this chapter ensure the more efficient delivery of network connection services? In particular, with relation to these models:

NEM Issue	Questions
	• How should the risks of connection be most appropriately spread across new connection parties, network businesses and end use consumers? • How do the connection charges change for new connecting generation plant and what benefits may arise? • How do the costs for end use customers change and what benefits may arise? • Are there any other potential models that we should consider to mitigate this issue?
A6. Augmenting networks and managing congestion	Do you agree that the issue of network congestion and related costs requires further examination under this Review to determine its materiality? This includes considering whether the existing frameworks provide signals that are clear enough and strong enough in the new environment where congestion may be more material? If not, what are your reasons for reconsidering this position?
A7. Retailing	Do you agree that the current inflexibility in the retail price regulatory arrangements is a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position? Do you agree that the limitations with current RoLR arrangements are a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position? Are there any additional options that could supplement the processes currently under investigation to address these issues?
A8. Financing new energy investment (also applies to Western Australia and the Northern Territory)	Do you agree that financing, as an individual issue, should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?

WA Issue	Questions
B1. Convergence of gas and electricity markets	Do you agree that the convergence of gas and electricity markets in Western Australia is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
B2. Generation capacity in the short-term	Do you agree that generation capacity in the short-term in Western Australia is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
B3. Investing to meet reliability standards with increased use of renewables	Do you agree that investing to meet reliability standards with increased use of renewables in Western Australia is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
B4. System operation and intermittent generation	Do you agree that, given an increasing amount of intermittent generation, system operation in Western Australia is a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position? Would any of the options identified in this chapter improve the efficiency of the balancing process in the WEM? In particular, we would welcome views on: • the practicality of introducing a competitive balancing regime; • other solutions (such as moving gate closure or introducing centralised wind forecasting) that could reduce the impacts in the balancing market of forecasting errors; and • the most appropriate charging regime for ancillary services in the WEM. • Are there any other potential models that we should consider to mitigate this issue?
B5. Connecting new generators to energy networks	Do you agree that the connection of new generators to energy networks in Western Australia is a significant issue and therefore should be progressed further under this Review? If not, what are your reasons for reconsidering this position? • Should incentives be provided for Western Power to ensure the timely delivery of connections, and, if so, how should risk be

WA Issue	Questions
	most appropriately shared under such a scheme? • Could improvements be made to the queue management process in Western Australia which do not conflict with the non-discrimination provision in the Wholesale Market Objectives? • In a Western Australian context, would any of the models identified in Chapter A5 ensure the more efficient delivery of network connection services? • Are there any other potential models that we should consider to mitigate this issue?
B6. Augmenting networks and managing congestion	Do you agree that network augmentation in Western Australia is a significant issue that should be further progressed under this Review? If not, what are your reasons for reconsidering this position? Would any of the options identified in this chapter improve the efficiency of network augmentation in the SWIS? In particular, we would welcome views on: • the practicality of including an evaluation of congestion costs in planning network augmentations; • other assumptions made as part of the planning process (such as the capacity factor of wind generation); and • the most appropriate locational signals for generation in the SWIS. • Are there any other potential models that we should consider to mitigate this issue?
B7. Retailing	Do you agree that the current inflexibility in the retail price regulatory arrangements in Western Australia is a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position? How can further work undertaken in this Review be best incorporated with the Office of Energy's ongoing Electricity Retail Market Review?

NT Issue	Questions
C1. Convergence of gas and electricity markets	Do you agree that the convergence of gas and electricity markets in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
C2. Generation capacity in the short-term	Do you agree that generation capacity in the short-term in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
C3. Investing to meet reliability standards with increased use of renewables	Do you agree that investing to meet reliability standards with increased use of renewables in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
C4. System operation and intermittent generation	Do you agree that system operation and intermittent generation in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
C5. Connecting new generators to energy networks	Do you agree that connecting new generators to energy networks in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
C6. Augmenting networks and managing congestion	Do you agree that augmenting networks and managing congestion in the Northern Territory is not a significant issue and therefore should not be progressed further under this Review? If not, what are your reasons for reconsidering this position?
C7. Retailing	Do you agree that the retail price regulatory arrangements in the Northern Territory may be a significant issue that should be progressed further under this Review? If not, what are your reasons for reconsidering this position?

Appendix C: List of supporting papers to the Review

AEMC Staff Papers

Survey of evidence on the implications of climate change policies for energy markets (AEMC 2008 Survey of Evidence).

Current arrangements for energy retailing in Australia (AEMC 2008 Retail Arrangements Paper).

Role of System Operator in Electricity and Gas Markets (AEMC 2008 System Operator Paper).

Supporting Consultant Reports

An Initial Survey of Market Issues Arising from the Carbon Pollution Reduction Scheme and Renewable Energy Target (McLennan Magasanik Associates) (MMA 2008 Initial Market Issues Paper).

Impacts of climate change policies on generation investment and operation (Frontier Economics) (Frontier 2008 Generation Investment and Operation paper).

Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements (Frontier Economics) (Frontier 2008 WA and NT Market Implications paper).

Market impacts of CPRS and RET (ROAM Consulting) (ROAM 2008 Market Impacts paper).

Timelines for Generation in the NEM (SKM) (SKM 2008 New Generation Timelines paper).

Historic and projected energy sector investment (Firecone) (Firecone 2008 Investment paper).

Financing of future energy sector investments in Australia: The potential effects of the Carbon Pollution Reduction Scheme and Renewable Energy Target (S3 Consulting) (S3 2008 Financing paper).

Climate change policies and the application of the Regulatory Investment Test for Transmission (Allen Consulting Group) (Allen 2008 Renewables and RIT-T paper)

Request for Advice from AEMC Reliability Panel

Update to Comprehensive AEMC Reliability Review quantitative assessment to account for CPRS and MRET (AEMC Reliability Panel) (Reliability Panel 2008 Advice)