Report to

Australian Energy Market Commission

An Initial Survey of Market Issues Arising from the Carbon Pollution Reduction Scheme and Renewable Energy Target

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MMA McLennan Magasanik Associates

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Project team

Scott Maves

Ross Gawler

Walter Gerardi

Lionel Chin

Paul Nidras

Salim Mazouz

Jim Stockton

Jay HortonStrategis Partners

Melbourne Office
242 Ferrars Street
South Melbourne Vic 3205
Tel: +61 3 9699 3977
Fax: +61 3 9690 9881

Brisbane Office
GPO Box 2421
Brisbane Qld 4001
Tel: +61 7 3100 8064
Fax: +61 7 3100 8067

Canberra Office
5 Patey Street
Campbell ACT 2612
Tel: +61 2 6257 5423
Fax: +61 2 6257 5423

Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

ACN: 004 765 235
ABN: 33 579 847 254

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GLOSSARY

Term	Meaning
AEMC	Australian Energy Market Commission
Black energy	Black energy refers to the energy as traded in the wholesale market. Currently black energy prices are affected by emission abatement products in NSW and Queensland, but the cost of these certificates may or may not be added to the wholesale prices depending on the context. In the future, it is expected that wholesale prices will be influenced by carbon dioxide emission permit prices.
CPRS	Carbon Pollution Reduction Scheme as proposed by the Commonwealth Government to reduce the level of greenhouse gases, including carbon dioxide, emitted in Australia
DKIS	Darwin Katherine Interconnected System
DNSP	Distribution network service provider
DSR	Demand side response
EUAA	Energy Users Association of Australia
GEC	Gas Electricity Certificates which are traded under the Queensland gas fired electricity scheme
Green energy	Green energy refers to any certificates that fund renewable or low emission energy that are directly related to the consumption of energy. Renewable Energy Certificates and Green Power Credits are current examples.
HVAC	High voltage alternating current – refers to conventional transmission technology
HVDC	High voltage direct current – refers to alternative to HVAC where the alternating current is converted to direct constant current for power transmission over long distances. The direct current is converted back to alternating current at the sending end for connection to the transmission system and conversion to customer voltage levels.
MWh	Megawatt hour
NEM	National Electricity Market
NETS	National Electricity Trading Scheme
NGAS	NSW Greenhouse Gas Abatement Scheme
REC	Renewable Energy Certificate for the Commonwealth renewable energy scheme
RERT	Reliability and Emergency Reserve Trader associated with the operation of the NEM. The RERT is a function conducted by NEMMCO to acquire additional reserve capacity when reliability standards are threatened. It currently operates up to 9 months ahead under the new reliability management arrangements.
RET	Renewable Energy Target defined in the Commonwealth renewable energy scheme
RPP	Renewable Power Percentage defines the proportion of a retailer's purchases at a bulk transmission supply node that must be covered by purchases of renewable energy certificates (RECs)
SWIS	South-west interconnected system in Western Australia that serves between Albany, Perth and Geraldton and the Goldfields

Term	Meaning
TCE	Transaction Cost Economics
TNSP	Transmission network service provider
VREC	Victorian Renewable Energy Certificate
WEM	Wholesale Electricity Market in Western Australia that serves Perth and the goldfields regions.

EXECUTIVE SUMMARY

The Australian Energy Market Commission (AEMC) has been requested to review the impact of the Carbon Pollution Reduction Scheme (CPRS) and the enhanced Renewable Energy Target (RET) on the Australian energy markets covering electricity and gas.

The AEMC engaged McLennan Magasanik Associates (MMA) to review some selected matters relating to the potential impact of the CPRS/RET policies on the electricity and gas markets. Specifically, MMA was asked to:

1. Review recent MMA modelling and analysis and identify the issues affecting the potential adequacy of the energy market frameworks. The particular focus is to encompass the wholesale and retail sectors of the gas and electricity markets.
2. Analyse the impact on organisational structure and strategy.
3. Analyse the impact on competition.
4. Analyse the impact on counter-party behaviour related to generator and retailer decisions.

Given a very limited period of time in which this review can be conducted, MMA has been asked to limit its assessment to an initial and preliminary review of potential issues for the energy market frameworks. Accordingly, many issues that are raised may need to be tested by further analysis and exploration. In many cases there is no recent precedent that can provide evidence of likely behaviour and the relative importance of various issues is a matter of judgement based on market modelling and observation.

To date our modelling and analysis has been prepared for clients such as the Garnaut Review, the Climate Institute, the Commonwealth Department of the Treasury, the Department of Climate Change, numerous state level departments and many market participants. Accordingly, it is largely specific to expected and likely scenarios affecting Australia. We recognise however that the energy market frameworks must be resilient to a range of less likely yet plausible scenarios. We have therefore extended our modelling observations to include further insights regarding a broader set of scenarios.

General uncertainties

There are a number of sources of uncertainty about the likely response of Australia’s energy markets to the implementation of CPRS and RET. Since these changes are unprecedented, it is not possible to rely on recent experience in the markets without a substantial amount of reinterpretation and future oriented quantitative analysis. The primary sources of uncertainty relate to:

- whether new generating capacity will be sufficient and timely to replace retiring plant and maintain bulk system reliability;

- whether the approval processes for new transmission services into remote energy supply regions can adequately recognise the opportunities to open up energy resources that are not yet commercially proven or committed but nevertheless require the new transmission infrastructure to be commercially viable;
- the ability of retailing to accommodate the impacts of significant structural changes within acceptable contract terms, particularly during a period of rapidly rising prices and price uncertainty in energy and emission abatement markets; and
- changes in the operating environment that could require enhancement to market infrastructure to address the day to day functional mechanics of contracts, assets and trading systems.

The following sections summarise important observations.

Wholesale Electricity Markets

- There are uncertainties related to reliability and security of supply as affected by potential delays to new entry and a deterioration of some coal-fired generating plant performance leading up to scheduled retirement. This may warrant further review as enhanced measures may be needed to address potential inadequacies relating to reserve trading, reliability analysis and the monitoring of plant reliability.
- Current arrangements for transmission development and pricing may not adequately support the relocation of generation clusters from existing coal based regions to regions near renewable energy resources and gas infrastructure. There are benefits in a review to consider how transmission investments can be encouraged so that new generation regions can be opened up without the risks that deep connection costs may overwhelm generation investment decisions. It may also be necessary to ensure that network charges are allocated to market participants so that the economic potential is maximised for replacement generation in the locations where coal fired capacity is retired.
- Better information on the cost, value, timing and location of transmission projects may be required to support a more active market in demand-side response and in embedded generation resources. Whereas the value of participation by distributed resources may markedly increase under CPRS and RET, there is currently minimal public information to assist planning of these resources by private investors. The information is largely held by TNSPs and DNSPs and is not published in a form that is useful for planning the aggregation of distributed resources. Rather it is provided on a project by project basis with lead times that are insufficient for long-term planning.
- Greater fluctuations in power flows and gas demand due to a much greater contribution from variable wind and solar sourced generation could enhance the value of day ahead trading markets in gas supply, gas transportation and electricity.

Wholesale Gas Markets

- Demand for gas from new power generation sources could increase[1]. Whilst a good part of this increase will be for base load and high intermediate duty, there may also be additional requirement for gas-fired generation to supply peak load and to back up variable generation resources such as wind. In some areas this may increase the fluctuations in gas demand on an intra-day basis, which could raise demand for peak shaving gas supply assets such as gas storage or LNG liquefaction/vaporisation plants, particularly in systems with limited active line pack capacity. The trading arrangements for gas supply and transmission may need to be more dynamic to manage the resulting constraints and to provide the correct signals for risk management and inter-market coordination in the gas and electricity sectors.
- Gas could be the transitional fuel in power generation. Transitional constraints could emerge within the gas infrastructure, particularly if investment lags develop, having implications for both the gas and electricity markets. In the event of these congestion problems, there may be potential for participants that control gas supply, transportation, storage, and generation assets to directly influence market outcomes.
- The ability of smaller producers to access "common infrastructure" such as treatment plants, storage, compression and LNG plants may become increasingly important in order to maintain competition in the gas sector, and to ensure that efficient gas market outcomes are transferred to the electricity and energy retail markets.
- Attempting to pass on carbon costs through existing contractual arrangements may result in contractual disputes. They are generally likely to be seen as additional imposts and passed on to customers, but this is not always the case. Standard price benchmarks to facilitate the management of the cost of carbon through the energy supply chain could be helpful.
- Integrated gas and electricity system planning processes may need to be made more robust, particularly to accommodate a departure from traditional incremental growth assumptions towards new processes that can accommodate the large and coordinated infrastructure investments that could be needed to support shifts in generation centres to new regions having renewable generation resources and significant gas infrastructure.
- System security requirements may be such as to require additional or new storage to be built, possibly with regulated pricing.

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1 According to the Treasury modelling, gas demand for power generation over the long term may increase under scenarios with modest cuts as there is switching to gas-fired generation. But the modelling also shows that a decline in electricity demand as permit prices increase can eventually result in lower demand for all fuels including natural gas. Thus in the scenarios with greater cuts in emissions, demand for gas for electricity generation falls relative to the reference case by 2050. Note also that demand for gas in other sectors may fall (the Treasury modelling shows an overall fall in gas mining in all CPRS scenarios modelled), potentially outweighing any gain in demand from the electricity sector.

Retail Markets

- The retail market will accumulate upstream cost pressures and market volatility, and may also be affected by contradictory regulatory provisions at the state level, impacting cost pass through and customer protection obligations. In particular:
    - We anticipate an increase in wholesale market prices and settlements volatility in both gas and electricity. Volatility could increase through inconsistent patterns of retirement and new investment, exercise of market power, and by an incompatibility in the spot market design logic with the changed operational and contractual realities affecting participants. This could disturb the efficient function of the contract markets, and heighten prudential, counter-party and credit risks within the organised and bilateral markets, reducing hedging opportunities for retailers.
    - It may become politically unacceptable in some states for small mass-market customers to experience large price increases. Price controls and more onerous customer protection arrangements may result. Small retailers with a customer portfolio bias towards this segment may experience difficulty, presenting implications for retailer of last resort arrangements, and causing some industry consolidation.
    - Demand management may become a significant transition strategy to manage energy scarcity in a scenario of investment delay and early coal unit retirement. Large controllable loads may therefore benefit with increased service innovation and price competition.
    - We have identified incentives towards horizontal integration, including dual fuel, appliance sales and installation and other bundled ancillary offers to cross-subsidise low margins in the mass market, and to seek advantage from potential government programs relating to energy efficiency rebates and incentives.
    - Greater integration into generation could occur under some circumstances, in part to overcome disturbances affecting the contracts market, and to benefit from, or to hedge, wholesale market price volatility that could otherwise squeeze the retail function.
    - Large national, dual fuel and vertically integrated utilities could increase market share if financial market instruments do not evolve to handle the uncertainties.
    - Some segments of the retail market may face limited competition, requiring more robust market monitoring and market power mitigation arrangements.

Potential issues that could benefit from further review

Most of these observations would only become problems if competition and reliable supply at the wholesale level were significantly eroded. Therefore the immediate focus should be addressing those emerging processes that could stumble under the current energy market frameworks. Sufficient regulation is needed to ensure that uncertainty is reduced where it arises from energy market policy objectives and frameworks. However, sufficient opportunity must be maintained in the energy market frameworks so that economic decisions are facilitated by commercial mechanisms wherever practicable.

In view of these observations, MMA considers that the following matters could benefit from further attention:

Transmission funding for new areas

- Establishing a process for the approval for and funding of transmission to the new energy regions.
- In the NEM, transmission development could benefit from a strategic long-term commitment and approval process for connection to new energy supply regions and for major interconnection upgrades as well as continuing the project by project bilateral negotiation process where that remains an effective process.

Reformulation of the reliability standard

- There are two separate issues related to reliability and the role of intervention. Firstly, the potential value of intervention during the transition phase requires a longer-term measure of required capacity in the power plant development pipeline so that the market performance can be effectively monitored. Secondly, the optimal value of the unserved energy may further deviate in some regions from its currently accepted level of 0.002%.
- A reformulation of the reserve capacity calculation to include the effect of the evolution of growth and plant performance uncertainties over at least a five year horizon could be beneficial. This revised reserve capacity measurement would provide the basis for longer term risk assessment and possible intervention of the Reliability and Emergency Reserve Trader (RERT) during the CPRS/RET transition phase. This reform would support the enhancement of the RERT role to support longer term planning processes as described below. This should not be interpreted as a need for a capacity market.
- A reformulation of the unserved energy reliability standard may be useful to more accurately reflect the cost of reserve plant (including demand side response), the uncertainties in thermal plant performance, the impact of expected patterns of variable generation and the uncertainty in demand growth following the CPRS and RET price adjustment. There is time to consider and refine this measure.

Enhancement of Reliability and Emergency Reserve Trader role

- The enhancement of the Reliability and Emergency Reserve Trader (RERT) role in the NEM to cope with potentially longer term capacity shortages up to five years in advance during the CPRS/RET transition phase. This does not require the RERT to establish a capacity market as such for the NEM but rather establish trigger points for which longer term contracting might be necessary to provide the necessary investment incentives in the event of market failure. The reformulation of the reliability standard to address longer-term uncertainties would provide the basis for a longer-term view of the risks of capacity shortage. This would provide important information to evaluate progress in the development pipeline as affected by new infrastructure requirements (gas and electricity transmission) and progress with environmental planning and approval processes. This would have to be done carefully to avoid market behaviour that leads this to be seen as a capacity mechanism.

Important Matters

There are also several important matters where economic efficiency could be enhanced but it is unlikely that inaction in the next year or so would create significant cost to the energy markets. Such matters include:

Resilience to retailer distress

- The systems that support retail contestability will need to be resilient against the risk of retailer distress on a wide scale. The Retailer of Last Resort arrangements may need to be scaled up to manage a larger number of customer transfers in a shorter period of time. Further, the interconnectedness of the gas and electricity markets and of their associated trading arrangements means that in the event that a participant becomes insolvent, a range of contracts and activities could fall over with interlinked effects on the gas, electricity, wholesale, retail, contract and even water markets. Insolvency provisions within the energy market frameworks may need to manage inter-market difficulties.

Trading systems for a dynamic environment

- The volatility of energy flows on an inter-day and intra-day basis may increase, having implications for gas flows and gas fired generation. The continuing reform of gas trading arrangements and the accommodation of gas sector operations within electricity trading functionality may be needed to prepare for these more dynamic market conditions.

On-going monitoring

There are a number of on-going operational matters which MMA considers can be managed under the current frameworks providing there is sufficient monitoring of market performance. These include:

- Setting standards for variable generation that will work at much higher levels of penetration into the system. NEMMCO and IMO have been aware of this challenge and have been taking action.
- The robustness of Retailer of Last Resort arrangements, as well as insolvency and credit management provisions throughout the energy market frameworks could benefit from a review, given that the functional extent of these arrangements are yet to be fully tested, and given that the risks of these processes being needed on a larger and more extensive scale could increase. Our understanding is that this is already being undertaken by the MCE.
- Ensuring that credit risk management systems can cope with the larger cash flows associated with carbon price transactions.

Further analysis

We identify a number of areas where further analysis and review is required to test potential issues that question the robustness of the energy market frameworks. These issues relate to:

- Potential market power and transitional congestion issues.
- The potential that new trading infrastructure may be needed to better facilitate trading in demand-response markets, to accommodate transitional issues affecting markets for capacity, augmented ancillary service markets, or functionality to improve contracting or settlements in the financial markets.
- The functional adequacy of market trading infrastructure, particularly to accommodate the potential that operational changes in significant assets and contracts may require new bidding constraints, dispatch logic, or other flexibilities to manage inter-market issues.

1 INTRODUCTION

The Australian Energy Market Commission (AEMC) has been requested to review the impact of the Carbon Pollution Reduction Scheme (CPRS) and the enhanced Renewable Energy Target (RET) on the Australian energy markets covering electricity and gas. A scoping paper has been released for public consultation which outlines a range of potential challenges for the energy markets due to the changes arising from CPRS and RET. The primary matters of uncertainty outlined in the scoping paper cover the following types of issues:

- the ability of the energy markets framework to accommodate a large scale increase in gas fired generation
- whether or not there will be sufficient generating capacity in the short term if investors delay their commitments or if there are delays in equipment delivery
- whether there will be a risk to the level of reliability associated with the increase in variable generation sources, particularly from wind energy
- will the current arrangements enable the market operators cope with the increased uncertainty arising from increase levels of variable generation?
- will increased co-ordination of connection of new generators be needed rather than being based on bilateral negotiations with network service providers?
- what is the risk of higher levels of congestion in gas and electricity transmission systems?
- how will retailers respond to the increased risks in wholesale energy purchase?
- will new energy investments be financeable?

The AEMC engaged McLennan Magasanik Associates (MMA) to review a selection of topics relating to the potential impact of the Carbon Pollution Reduction Scheme (CPRS) and the enhanced Renewable Energy Target (RET) on the Australian energy markets covering electricity and gas. Specifically, MMA was asked to:

1. Review recent MMA modelling and analysis related to the proposed Carbon Pollution Reduction Scheme (CPRS) and expanded national Renewable Energy Target (RET) and identify the issues and potential threats for energy markets. The focus is to be on the potential outcomes related to generator and retailer behaviour that may require attention within the energy markets frameworks
2. Analyse the impact on organisational structure and strategy
3. Analyse the impact of CPRS/RET on competition
4. Analyse the impact of CPRS/RET on counter-party behaviour related to generator and retailer decisions.

The report focuses on the insights gleaned from MMA's work in market modelling, mostly for the National Electricity Market (NEM) and the south-west interconnected system (SWIS) in Western Australia. We have also modelled the Pilbara and the Darwin-Katherine system and some of the issues would apply in those systems as well, although we have not addressed specific issues for those systems in this report. For example extending the system to capture local renewable energy resources may require investments that are out of scale relative to current commercial operations.

This current analysis is based on our experience in the Australian electricity and gas markets dating back to the late 1970s. This experience of how the Australian gas and electricity markets have developed from state-based regulated industries to national competitive frameworks provides the background for MMA's modelling work. Electricity and gas markets are complex and it is not practical to capture all market phenomena in any set of computer based mathematical models. Therefore, the ability to understand the major market activities of participants and how they respond to market signals is an important part of driving market models and using them to forecast outcomes. MMA's work in this respect has been central in designing the original renewable energy target and the more recent work on the earlier state-based activities for a National Emissions Trading Scheme (NETS) and more recently the CPRS.

Through this work we have gained an appreciation of:

- the costs of new generation assets and long-term trends in cost and performance
- the options available for renewable and fossil fuel based generation
- how the various renewable and thermal resources would be best developed and dispatched to meet total energy needs
- the impact of carbon price and renewable energy targets on dispatch and development
- the impact on the main transmission system of changes in the patterns of generation
- the costs imposed by variable generation for which the timing of output cannot be accurately predicted
- the impact of premature plant retirements on market prices
- The importance of bidding strategies to delivering sustainable prices in an energy only market design.

This work, MMA's studies conducted for the Energy Users Association of Australia (EUAA) on national transmission planning and the reliability standard and MMA's electricity price forecasting for market participants have informed the analysis presented in this report. The work on the CPRS and RET in many projects informs our insights about investment, retirement and price outcomes.

1.1 Structure of the analysis

The aim of this initial report is to present a working list of issues that may become of concern as the energy markets transition to a low emission future.

The structure of the report is as follows:

- Chapter 2 summarises observations and a qualitative analysis of the wholesale electricity markets, based on our analysis over the last ten years. The narrative provides an assessment of potential adverse impacts arising from the implementation of CPRS and RET in relation to the market objectives.
- Chapter 3 provides an analysis of the various factors that could threaten the resilience of the energy market frameworks. It describes how the current energy markets frameworks could prove inadequate and recommended some actions to confirm that the arrangements will remain robust.
- Chapter 4 then discusses the matters of uncertainty in relation to competition, organisational structure and counter-party behaviour based on expectations about wholesale market behaviour relating to investment and transmission development.
- Chapter 5 outlines the next steps that would be useful to help plan out the changes that could be beneficial in the energy market frameworks and then draws some final observations about the range of matters considered in the report.

2 ISSUES AND OBSERVATIONS FROM MMA MODELLING AND ANALYSIS

2.1 Overview

This chapter draws on the results of recent market modelling by MMA and indicates the potential rate of change in the wholesale electricity market. Some information on gas markets is also included based on our knowledge and experience in modelling and observing wholesale gas markets in Australia.

2.2 Background on MMA's market modelling

It is useful to outline the context of MMA's modelling of the Australian energy markets. Much of MMA's work has been for investors and for governments. For investors the focus has been on conservatively estimating the revenues of proposed acquisitions and revenue forecasting for new projects. For governments, the focus has been on estimating the effects of new emission abatement schemes such as NGAS, GECs, RET and CPRS.

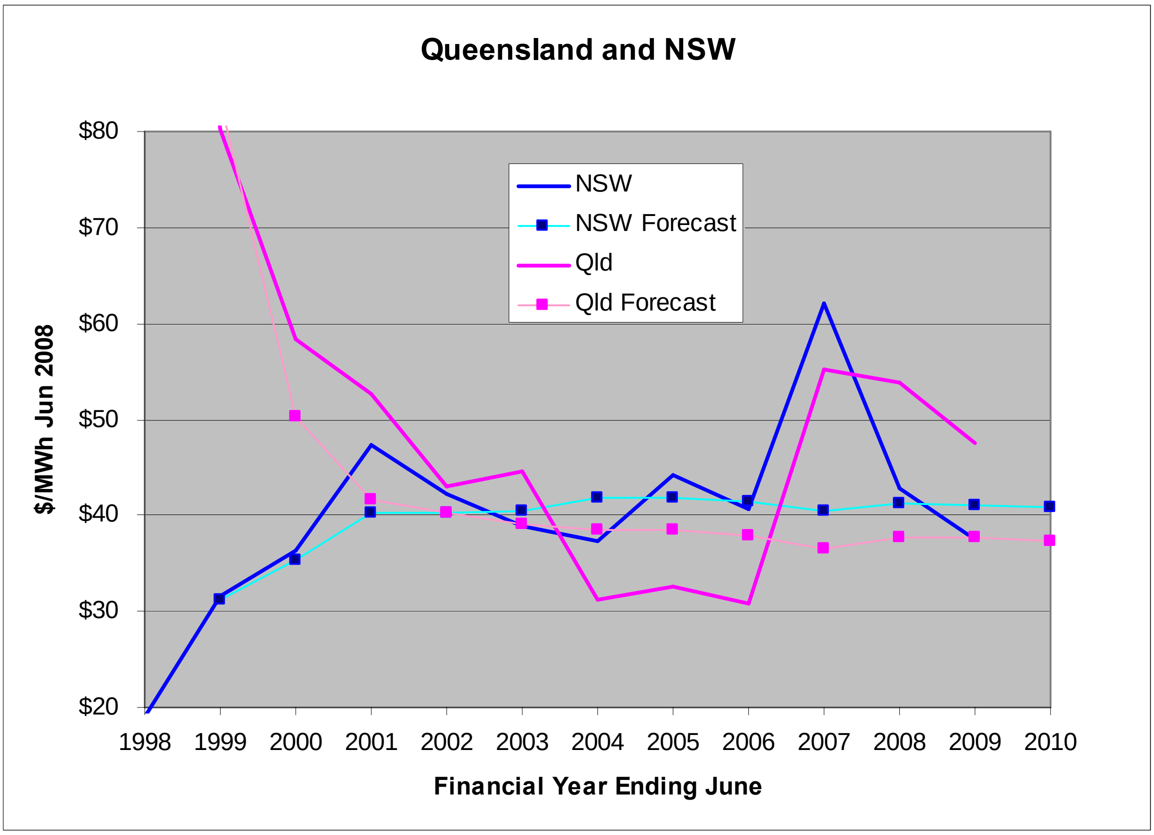
Figure 2-1 shows a history of NEM regional prices and the average of MMA forecasts for each financial year. The forecasts are included in the average if they were made at least twelve months before the financial year.[2] It is evident that price forecasts are much more stable than actual price outcomes in the spot market due to the inherent volatility of spot prices. This also reflects the difficulty of making projections about investment and operating behaviour because:

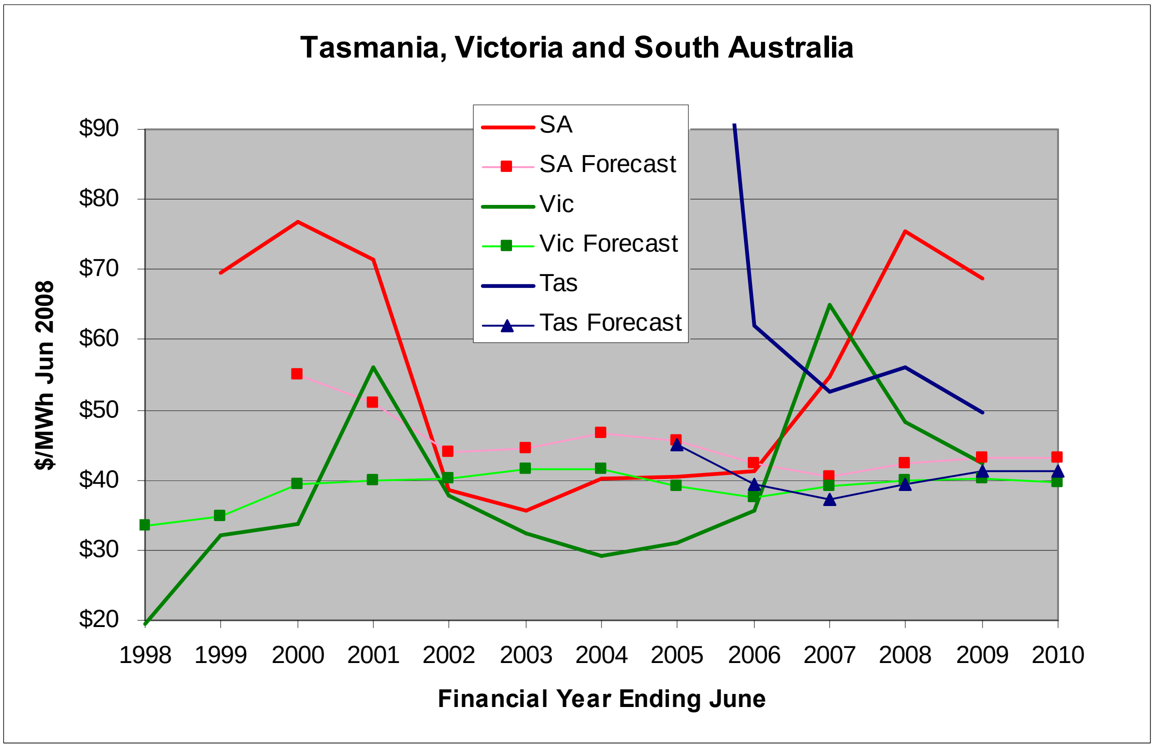
- future outcomes are inherently difficult to predict as there are many influences on electricity markets that cannot be fully anticipated
- market participants do not have perfect foresight about investment opportunities and outcomes and unfortunate decisions are made, based on assumptions that do not eventuate
- often the forward contract market is taken as a reliable measure of future trading conditions because it is the synthesis of many participants' views about future conditions. However, it too suffers from inadequate foresight.

Even though forecasts will never be absolutely accurate, the modelling work does show the impact of decisions and the effect of supply and demand balance on price outcomes in a useful way. We may observe the effect of emission costs on incumbents and new entrants and the requirements for replacement capacity as old plants retire. The impact of the renewable energy target is that it brings on new capacity independent of growth in demand in the regions where renewable energy resources are of lower cost and where

2 MMA produces a quarterly report summarising the performance of its NEM price forecasts. It is available at www.mmassociates.com.au.

Figure 2-1 History of MMA's price forecasts for the NEM





energy costs are higher. This may cause imbalance of supply and demand if investors are not able to fully assess the impact of their investment decision in affecting market prices.

The commentary in this chapter is based on MMA's experience in developing long-term models of the NEM and the SWIS. These models are used with spreadsheet models to represent the renewable energy market and trading in the other emission abatement products. The useful information available from these models is:

- price outcomes
- investment sequences
- interconnection energy flows
- distribution of renewable energy projects
- fuel consumption
- carbon dioxide emissions.

2.3 Demand uncertainty

2.3.1 Demand growth

One of the key uncertainties relates to the impact of CPRS and the flow through of the RET costs to customers and how that will affect the consumption of electricity. Economic growth is a key driver of electricity demand. Its affect is moderated by the electricity intensity of the economy which depends on the business mix and technology trends. The Australian industry has substantial energy consumption for aluminium smelting which may progressively reduce as CPRS provides incentive for this activity to move where lower cost electricity is available. However, the more immediate effects are expected from:

- Improvements in building energy efficiency which reduces peak demand in the commercial sector and residential sectors.
- More efficient appliances that reduce energy consumption generally.
- Customers being more careful about their consumption in response to higher retail prices and eventually choosing more efficient appliances.
- Increased use of local energy resources, particularly from solar thermal and photovoltaic technologies using the existing building infrastructure, thus reducing net demand drawn from the grid and supplying the grid locally.

There are a number of studies where response to higher prices has been modelled to attempt to quantify the range of effects. Recent work by ACIL Tasman for the ESAA[3] has projected load reductions of 12% to 14% by 2020 for emissions reduction of 10% to 20% below 2000 emission levels with carbon prices by 2020 of $45 to $55/t CO_2e in 2008 dollars. Modelling of the CPRS for the Treasury indicate demand reductions (relative to the reference scenario) of 12% caused by an emission target of 5% reduction on 2000 levels and a reduction in demand of 23% caused by an emission target of 25% reduction on 2000 levels. The estimates for the Treasury modelling indicate a slightly more sensitive

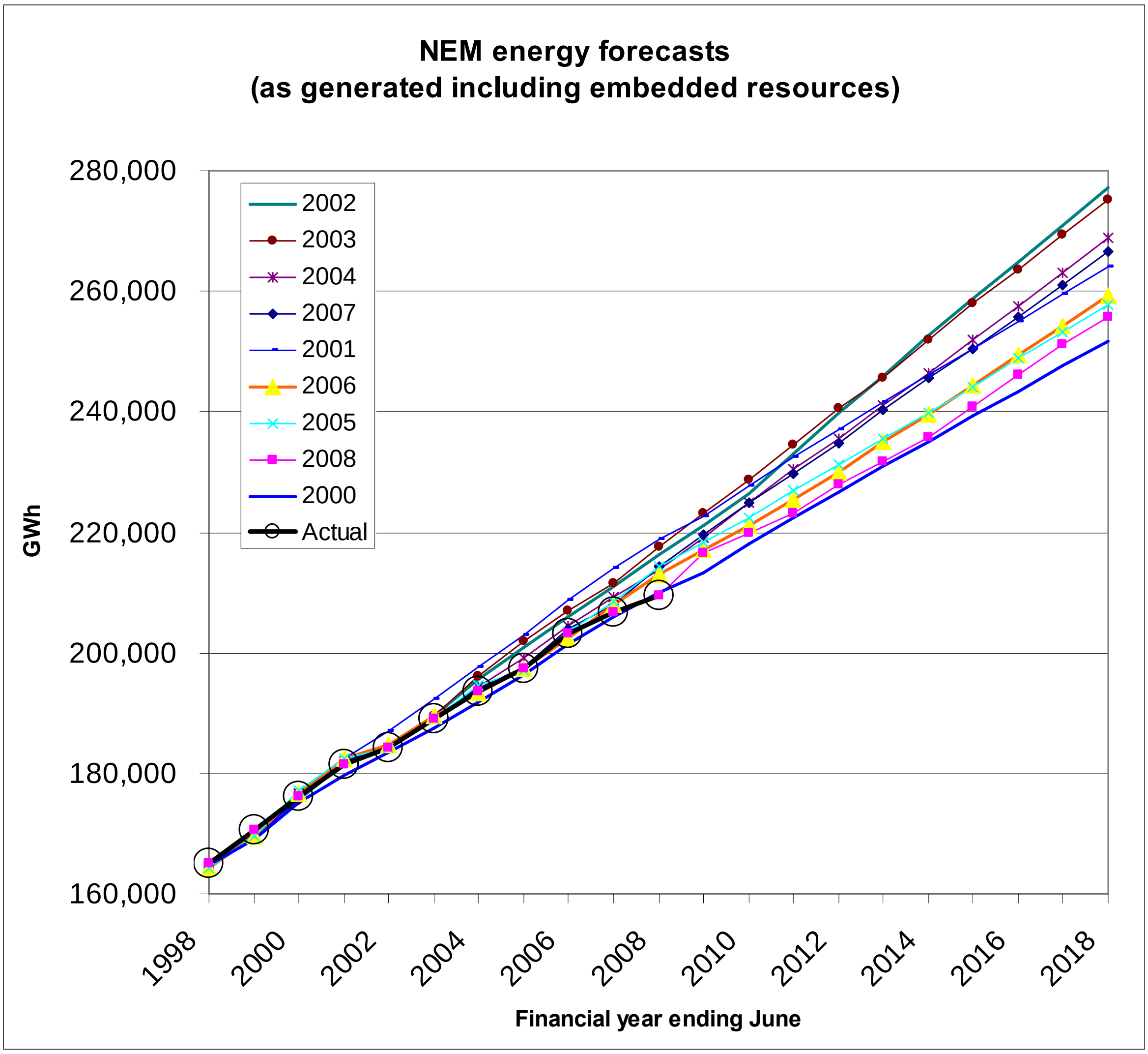
[3] Energy Supply Association of Australia, "The impact of an ETS on the energy supply industry" June 2008

response of demand to higher electricity prices. All studies indicate that even for modest target reductions, demand is either steady or still growing slightly albeit at a much lower rate than without emissions trading. Even where demand is steady, this only occurs for a short duration and growth in electricity demand eventually ensues.

Managing demand uncertainty is not so difficult unless growth rate is so low that no growth is a realistic possibility. This increases the financial risk of investment in new capacity that is not matched to retirement of old capacity. The current concerns about economic recession may exacerbate the uncertainties related to customer response to the higher energy prices that will result from CPRS and RET.

An analysis of total NEM energy forecast as shown in Figure 2-2 shows that they are progressively decreasing over time and that the actual demand has normally followed below the median forecasts. This is not surprising as the risks of shortage in supply are greater that the risks of a surplus supply in terms of total economic cost due to the leveraging value of electricity in the economy. Therefore one would expect that forecasts

Figure 2-2 History of NEM energy demand forecasts



for planning purposes would tend to be slightly optimistic for them to reflect this risk profile.

If investors thought that the down-side picture is stronger that the upside, then this demand uncertainty may inhibit timely investment. One advantage of the RET is that it will require additional investment in generation that will be supported by the revenue from the RECs. Thus the renewable energy program will ensure that there is some expansion of energy supply that would mitigate any hiatus in thermal plant development, at least to about 2014, based on MMA market modelling.

2.3.2 Aluminium smelting

Aluminium and zinc smelting uses about 2700 MW of base load power in the NEM. The shut-down of this demand would have a major impact on the generation sector and carbon emissions. Given that the pressure for closure of coal fired generation would be strengthened by loss of this demand, it would seem that the energy market frameworks would be able to deliver appropriate responses to loss of this demand.

Since the Rio Tinto smelter at Bell Bay is very large relative to the Tasmanian electricity demand, its closure could have a dramatic effect on the viability of renewable resources in Tasmania, unless the low hydro yield continues indefinitely and this is foreseen by investors. The energy market frameworks would provide the incentives to examine upgrading Basslink capacity under this scenario to permit the higher levels of export required if the wind potential of Tasmania were to be developed and if Hydro Tasmania returned to its historical level of hydro generation.

2.4 Pricing impacts

The dominant effect of CPRS will be to remove wholesale price discounts from existing emission abatement schemes and then to add a carbon price impost to the energy price. These effects are explained in this section.

2.4.1 Removal of discounts

The first effect of CPRS is to remove the discount that currently applies to wholesale market prices due to the revenues provided by the NSW Greenhouse Gas Abatement Scheme (NGAS) and the Queensland Gas Electricity Scheme. The wholesale energy price is lower in the NEM because these schemes cause gas fired generators to bid lower prices so that they can produce revenue from these products. The lower bid prices lead to discounted market prices that would be less than prices based on the short-run marginal cost (excluding the benefit of abatement revenues). These discounts partially compensate customers for the cost of the emission abatement costs incurred by their retailers and they reduce the profitability of high emission coal fired generation. In part, coal fired generators outside NSW have also borne part of the cost of reducing emissions under NGAS due to lower energy market prices.

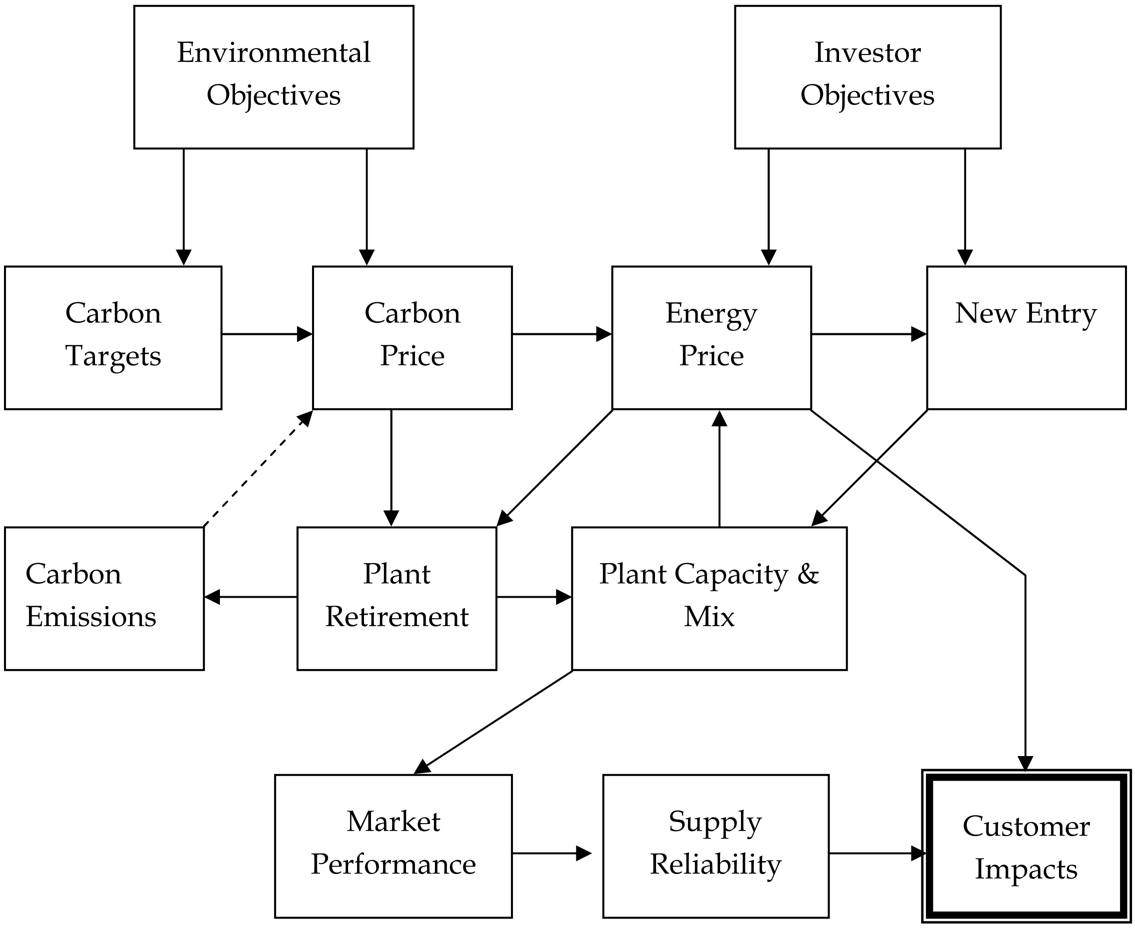
2.4.2 Carbon cost added

The CPRS will then raise spot energy market prices as generators bid their carbon costs into the spot market. Even if generators have received emission permits for all of their planned output, they would have the incentive to bid the market value of their permits as they can choose not to generate, thus not to emit the allocated CO_2 and then sell the surplus permits. Thus we do not expect the holding or sale of emission permits to have any significant effect on energy market prices. The main driver of energy price will be the market value of the carbon emission permits. This may be set through an administered price or through market responses to the total permits on issue and the constraints on banking and borrowing.

2.4.3 Impact of new entry

The critical determinant of spot and energy contract prices is the retirement program and new entry development. These dependencies and associated objectives of participants are illustrated in a simplified way in Figure 2-3. If there are any delays in new entry, then plant retirement may be delayed due to higher prices. This would result in higher emissions which may feed back to higher carbon prices either directly though a shortage

Figure 2-3 Electricity Price determinants and impacts



of permits (if no more are available) or indirectly through higher cost of replacement permits if the Australian scheme is linked to external carbon markets. Thus, if there is any reluctance to deliver new replacement capacity despite seemingly attractive market prices, then energy and carbon prices could be higher than if efficient investment occurred.

2.4.4 Price volatility

Price volatility that arises from the normal course of plant performance and contracting would remain the same after CPRS and RET as these factors would be substantially unchanged. However, there are three sources of additional price volatility, one of which is certain and the other two sources may wax and wane:

- Carbon price adds a new pricing variable into the equation and to the extent that the carbon price itself fluctuates, it will be reflected in energy prices as a varying source of price change. These price changes will vary slowly because carbon emission permits will be bankable. Thus the carbon price is not expected on its own to contribute significantly to day to day price volatility.
- Any delays to new investment due to market uncertainty could bring capacity margins closer to that managed through the RERT role and this would increase the day to day volatility, particularly if plant forced outage rates were to increase due to impending plant closure and avoidance of other than necessary maintenance. This source of price volatility will vary according to reserve margins and plant performance.
- Increase in the amount of variable generation would be expected to increase day to day price volatility, especially if insufficient energy reserves are available during periods of low wind speeds. Overnight prices could also be very low if high wind coincides with low demand and high levels of minimum coal fired generation, such as often occurs in the WEM. This source of price volatility will grow as the amount of variable generation grows and decrease as more inflexible thermal power generation sources are retired.

In Section 3.2.2 we further consider price volatility issues including a broader view of volatility across the wholesale, retail and contract markets.

2.5 Coal plant retirements

One of the major outcomes from the analysis is the potential for the closure of coal fired generators. Some coal fired plants might change ownership if the current owners become insolvent due to their debt burden and the unwillingness of the existing shareholders to refinance the business. If this happens at very low capital cost where the power station still has some net economic value, we would expect the new owners to continue to run the plants until they become cash flow negative.

Even if some coal-fired generators are provided with sufficient emission permits to keep them financially viable, they may still have an incentive to sell their permits and to close some or all of their capacity. As more units close, the business will become progressively less viable, until the avoidable cost includes all the management overheads and the whole business is closed. We would therefore expect a progressive closure of units and then a final shut-down of remaining capacity. It is possible that some of the plant might be part of a repowering strategy with lower emissions and carbon capture. However, due to the design and age of the generating plant, it would appear that this is unlikely to occur to any significant degree before 2025, if at all.

There has been some concern expressed that coal plant could close down prematurely if the owners of those plants become insolvent. Some privately owned plant have very high gearing ratios and even modest carbon prices may see the equity dissolve. To the extent this occurs, this does not mean early closure as debt owners would effectively take over the assets and as long as fixed operating costs were being recovered they could sell down the assets to its lower value[4].

All of the studies on emission trading undertaken to date indicates that the most vulnerable generators are the Victorian brown coal generators. Some scenarios of brown coal plant closure from recent published analysis are shown in Table 2.1 for a range of carbon prices and demand growth. Although there is agreement of plant closures, estimates of the amount of closure vary widely. Lower levels of closure in the period to 2020 occur with the Treasury studies than with the other studies. Carbon prices below $\$20/tCO_2e$ would not be expected to have a major impact on brown coal operation, although they would impair business value and profits depending on the allocation of emission permits. For most published studies, carbon prices are higher than this.

Potential reasons for the lower levels of retirements in the Treasury study include:

- High gas prices and higher levels of renewable energy would defer the need for new gas plant, which would be the main competitor to brown coal generation.
- Large demand response (fall in demand) delays the need for new plant to compete with brown coal plant.
- Lower carbon prices and a more gradual trajectory in carbon prices with the Treasury modelling.
- Treasury analysis conducted over the long term (to 2050), which affects investment patterns before 2020. In particular, the increasing gas prices and the successful development of CCS technology for coal generation limits the early entry of new gas plant as the economics of this new plant is affected by carbon prices and market developments beyond 2020.
- Adoption of a unit by unit closure regime which results in improved prices for remaining units.

[4] By analogy consider the mortgage market. If a householder is not able to repay the debt on their home and the value of the house has fallen below the debt level, it is unlikely that the banks would shut down the house. Rather the bank would normally attempt to sell the house to recover as much of its debt that it can.

Table 2-1: Brown coal generation plant retirements in 2020

Item	ESAA 10% Case	ESAA 20% Case	Treasury CPRS -5	Treasury Garnaut -25
Capacity retired[5], MW	4,335	4,335	1,600	2,820
Carbon price, \$/t CO_2e	45	55	34	61
Gas Price, \$/GJ	\$5.80	\$5.80	\$6.04	\$6.04
Demand reduction (Across the NEM)	12%	14%	12%	23%
New high duty gas plant capacity in Victoria, MW	2,700	2,300	500	500
New renewable energy, MW	2,800	3,500	3,800	4,200

The earliest that brown coal could be closed entirely would seem to be about 2020, but this would require a huge rate of investment in new capacity as discussed below. Even in the Treasury Study most plants except Loy Yang are closed by 2030 in most scenarios.

The modelling of base load generators' retirements by MMA assumes that revenue consists of spot market revenue plus contract market revenue. Ancillary services revenue for brown coal plant is deemed to be of negligible importance. When the available revenue is less than the avoidable operating costs, the plant is considered for retirement one unit at a time. The avoidable operating costs consist of:

- the variable operating and maintenance costs which are associated with the consumption of water and materials and the impact of wear and tear on future maintenance costs on a present value basis
- the fixed operating cost of the generator, which includes manning and maintenance contract costs
- the variable fuel cost, where applicable
- the fixed fuel cost when the fuel supply contract can be terminated without penalty.

5 Generation basis

For the large base load units, closing a unit would normally have an impact on supply and demand and would be expected to increase the duty of peaking plant and increase the market power of the dominant remaining generators. Therefore, generator units would be expected to retire one or two units at a time to see if the resulting price increase is sufficient to keep the remaining units viable. It would be unlikely that a whole power station would close at the one time due to the resulting very high prices that would result in the spot and contract markets. The NEM design would encourage a gradual replacement of non-viable units due to the sensitivity of market prices to the balance of supply and demand. The same would apply in the SWIS, although the influence of the short-term market (STEM) would not be as significant as the spot market in the NEM.

2.6 Competition and construction capacity for new entry

A critical factor in this analysis is the ability to deliver new capacity in a region. If we were to attempt to replace all the Victorian brown coal plant in ten years (it took thirty years to build the current assets) as well as meet growth, we would need a substantial increase in construction resources which may not be available at low cost. Therefore a key aspect of modelling is the assumption about the rate at which new plant can be added. If new entry production is limited, then market prices might well exceed new entry costs for a time until the development can catch up with requirements. Higher energy prices would have the economic benefit of maintaining the older plant in operation so that reliability is not adversely reduced.

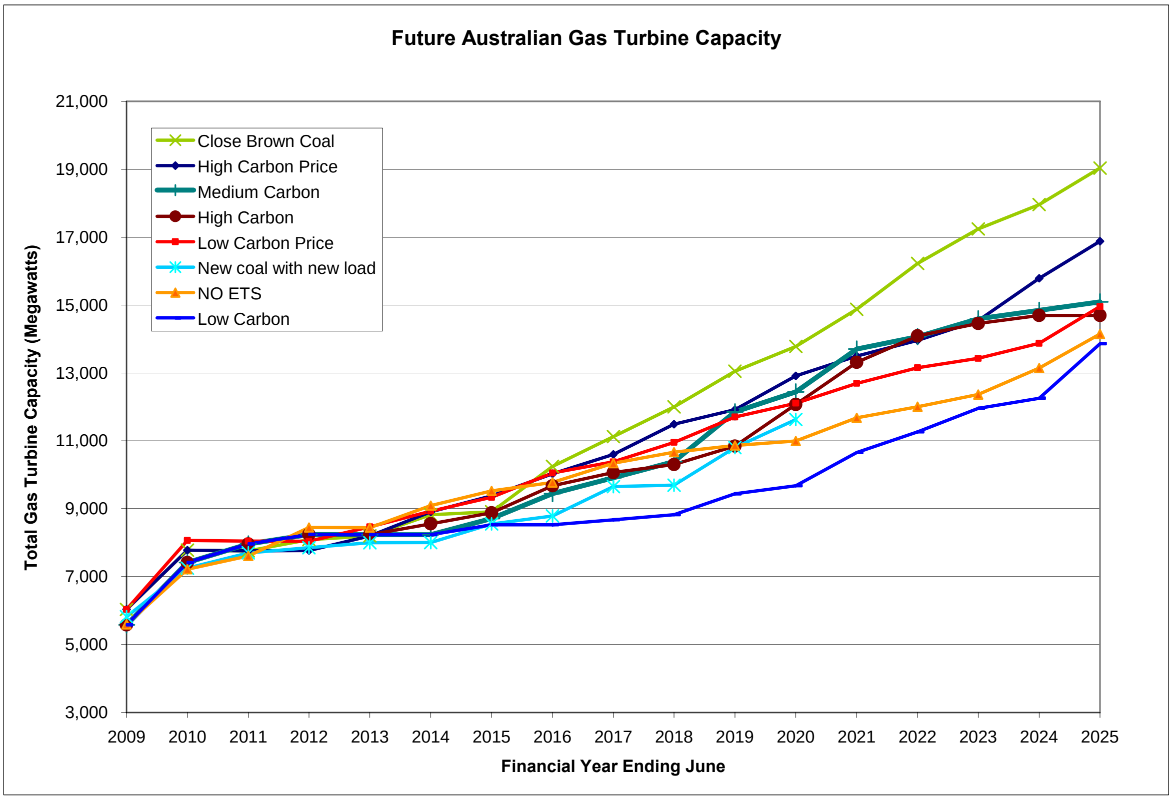
An analysis of the required rate of addition of new gas turbines has indicated that about 550 ± 100 MW per year of new capacity will be required in the NEM in the period to 2020 as indicated by Figure 2-4, assuming no demand reduction in response to the CPRS. This is estimated to include gas turbines needed for combined cycle plant as well as advanced coal fired technologies.

The ACIL Tasman study for ESAA[6] published in June 2008 showed a requirement for 5,000 to 7,000 MW of additional gas turbine capacity by 2020 which is in the middle of the range (between 11,000 and 13,000 total MW) shown in Figure 2-4 by 2020. Thus there is a consistency in these results.

The lower growth in the period to 2014 reflects the current state of commitment to new capacity and the expected impact of the expanded RET scheme. This rate of installation would not appear to present major challenges for the Australian industry. The potential for an increase to 1000 MW gas turbine capacity per year after 2015 with high carbon prices and early closure of brown coal fired generating plant might well represent a major challenge for the southern regions of the NEM.

[6] Energy Supply Association of Australia, "The impact of an ETS on the energy supply industry" June 2008

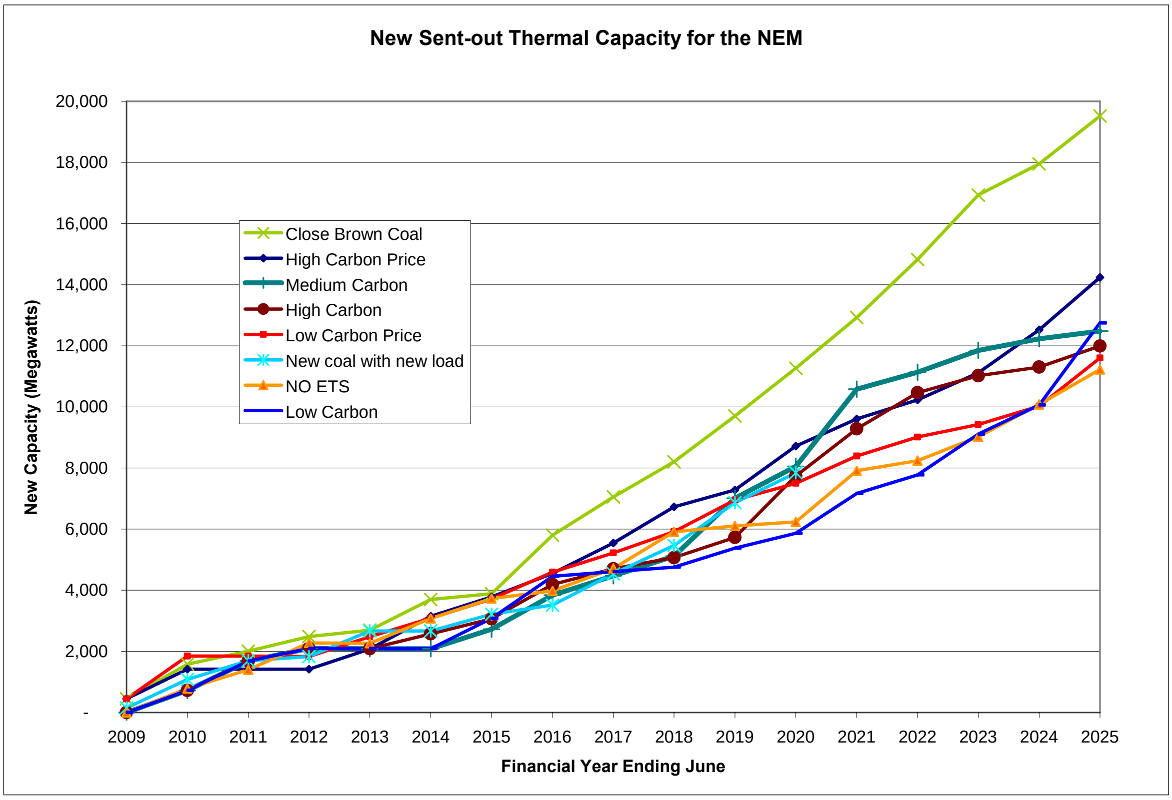
Figure 2-4 Need for new gas turbine capacity in the NEM



The corresponding data for all thermal capacity is shown in Figure 2-5. The case with early closure of brown coal has virtually unrestricted new replacement capacity. The additional 12,000 MW capacity would be 2/3rds based on gas turbines and 1/3rd steam equipment for most of the scenarios. The average rate of installation is 750 MW per year. The increase in thermal and hydro capacity in the NEM from 1999 to 2009 was 834 MW/year on a generated basis based on 37,523 in winter 1999 and 45,863 in winter 2009 according to the 2000 and 2008 Statements of Opportunities. Thus the required rate of development with respect to thermal plant is comparable with the rate over the last 10 years. The only concern is that we also will need to add another 8,000 MW of renewable energy capacity over the period to 2020 which doubles the requirement on a capacity basis. This may cause constraints on construction resources, particularly while the Federal Government is pursuing infrastructure development in other sectors simultaneously.

The current financial crisis would also be expected to increase the cost and availability of capital in the short term. This could disrupt planning and financing processes and add to project development lead times. Whether or not the current conditions will have any lasting effect on projects planned for service beyond 2010 is very difficult to assess at the present time.

Figure 2-5 Projections of new thermal capacity for the NEM



2.7 Reliability

Reliability is an out-working of the balance of supply and demand as affected by installed capacity, plant reliability and the volatility of variable generation sources. The current framework provides the NEM with a RERT and the SWIS with a reserve capacity market to provide management of reliability and to reduce the risk of unsatisfactory reliability. Even these arrangements cannot guarantee economic reliability due to:

- Exposure to forecasting error for demand and plant performance
- Exclusion of consideration of non-credible contingencies which are deemed to have a low probability[7]
- Lead time constraints in responding to unfavourable trends
- The level of the unserved energy standard being applied to all NEM regions and the SWIS as if it were a universal parameter (0.002% of energy demanded).

To the extent that CPRS provides additional sources of uncertainty relating to investment and demand response, the frameworks for the management of reliability may need to be modified to deal with changes to plant performance and investment activities as affected by CPRS.

[7] Many non-credible contingencies are not included in formulating the reliability standard because providing additional reserve capacity is not the most economic way of mitigating their impact. Normally design standards, supplementary controls and management system improvements are the best way of avoiding or mitigating multiple contingencies arising from a single cause.

MMA's market modelling has mostly found that if new entry is delayed due to financial or construction and delivery constraints then plant retirement could be delayed through higher energy prices with only a modest decline in system reliability over the medium term.

2.7.1 Reserve requirement and reliability standard

The current reliability standard of 0.002% expected unserved energy was established in 1998 when the NEM commenced and was reviewed and confirmed in the December 2007 report of the Reliability Panel[8]. When the NEM was established, the 0.002% unserved energy reliability level was established as consistent with industry practice prior to the NEM and it has remained unchanged since the market start. The AEMC Reliability Panel Report in December 2007 stated that there were no recommendations by stakeholders to amend the standard[9] and confirmed that the form, level and scope of the standard should remain unchanged. The only change was to define it more clearly as being monitored as an average outcome over the long-term with a view of monitoring levels over a ten year period. It would be applied in market modelling looking forward as an annual target when monitoring capacity requirements and quantifying volumes as the basis for intervention in the provision of additional reserve capacity.

MMA analysis conducted for the 2006 Comprehensive Reliability Review[10] showed that the current reliability standard is not quite optimal with an indicated cost error away from an optimal standard adapted to each region of amount $9M per annum now and potentially increasing up to $40M per year if the standard was closely achieved. This is not an immediate concern due to the relatively small magnitude of the excess costs imposed on the NEM as a whole. However, if the current unserved energy standard and reliability monitoring processes are maintained during the CPRS/RET transition, this cost of the current standard might increase.

The current reliability standard could become less efficient if there was greater uncertainty about plant performance leading up to plant closure, if there was a much greater penetration of variable generation or if load growth became more uncertain. All of these factors are expected to be a feature of the electricity market during the CPRS/RET transition. The unserved energy target would be expected to differ among the regions and the target reserve margin would be increased over time to manage the wider range of uncertainty.

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8 Australian Energy Market Commission, "Comprehensive Reliability Review, Final Report", December 2007

9 MMA disagrees that there were no recommendations to change the level of the standard. The Energy Users Association of Australia submission highlighted the inefficiency of the 0.002% as between $9M and $40M per year based on market modelling. The EUAA submission recommended that an economic review be conducted and that the standard be adapted to regional differences. This would have addressed the fact that VoLL would have different impacts on capacity in each region according to the regional supply and demand characteristics.

10 Estimation of the Economically Optimal Reliability Standard for the National Electricity Market. McLennan Magasanik Associates for the EUAA, 16 June 2006. Available at www.mmassociates.com.au.

If the current unserved energy standard, reserve margin calculation and short-term intervention processes are maintained during the CPRS/RET transition phase, there is a risk of:

- Premature intervention if the reliability standard is too stringent or the assessed reserve margin is too low. Based on the 2006 MMA studies, it is arguable that this may have occurred in Victoria and South Australia previously in the period 2005 to 2006.
- Late intervention in response to an investment delay if the reliability standard is too lax or the assessed reserve margin is too high. There is no evidence that this has occurred as yet in the NEM or WEM.
- Low reliability if capacity or short-term energy reserves are not sufficient to manage the variability of wind generation.
- Deferment of investment by the private sector if frequent intervention by the RERT occurs due to reliability standards that are too stringent. There is no evidence of such behaviour as yet in the NEM or WEM.

These risks can be addressed by:

- reviewing the economic basis of the reliability standard for the prospective new market conditions and uncertainties; and
- extending the scope of the RERT processes to monitor market investment planning and commitment behaviour and its potential impact through the transition phase over a period of up to 5 years ahead.

The application of the unserved energy standard to calculate required reserve margins is currently used only for short-term capacity assessment for a period of less than one year. The uncertainties due to economic growth and long-term plant performance trends have not needed to be considered. This could change with the potential impact of the coming CPRS/RET schemes. Concerns about longer term investment decisions for power lines and gas pipelines and development of new replacement technologies indicate that capacity monitoring may be needed over a longer period, for up to 5 years ahead.

For example, the key question during this transition is whether there are sufficient new resources going through planning and environmental approvals to ensure the necessary optionality to address the market uncertainties. Greater uncertainty usually leads to the need for higher reserve margins in the future for capacity planning purposes. This approach becomes more valuable when faced with the potential impacts of a sudden price increase.

2.8 Transmission constraints

2.8.1 Mainland

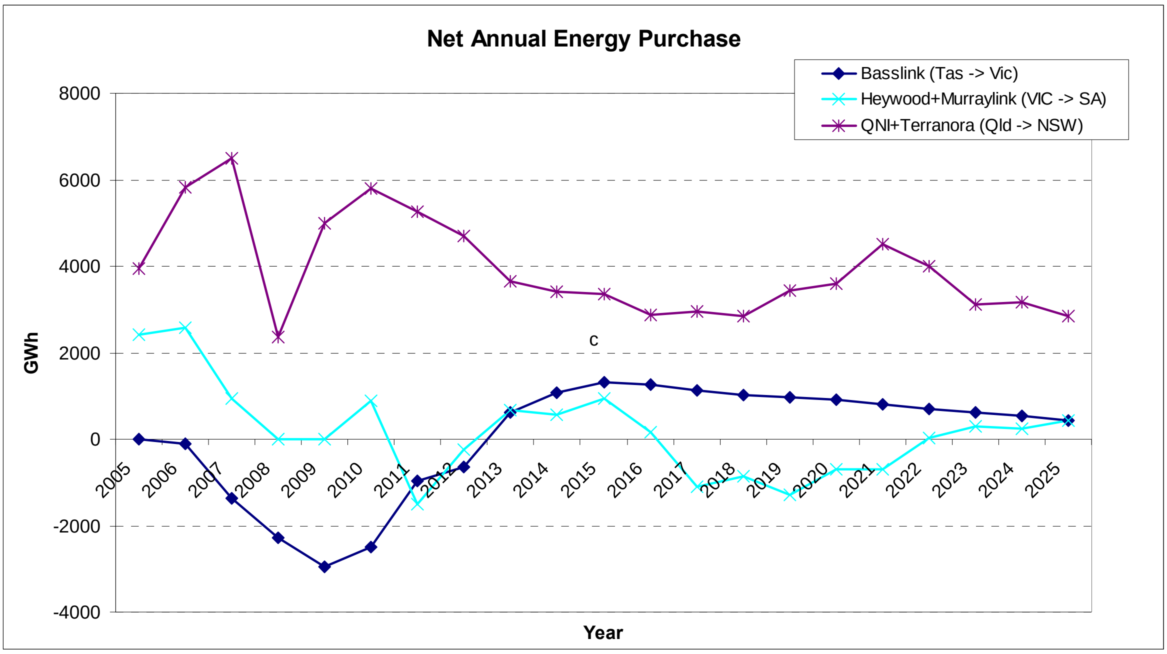
The utilisation of the NEM interconnectors is projected to change in response to CPRS and RET as follows:

- The QNI and Directlink interconnectors will continue to direct energy south for some time due to lower energy costs in Queensland and the expansion of coal seam gas fired generation.
- The Heywood and Murraylink interconnectors are in the process of changing from serving South Australia with base load power since 1990 towards enabling the export of peaking power and renewable energy from South Australia to Victoria. These interconnectors may become constrained more frequently if more wind power is developed in South Australia and Tasmania and if brown coal plants are closed in Victoria. The interconnection could become a major impediment to the connection of geothermal power in South Australia unless its performance is upgraded for export of power from South Australia. The Heywood interconnection may also provide a constraint on the amount of wind power that can be connected in South Australia.
- The Victoria-Snowy-NSW interconnectors[11] will become the major mode for supporting the replacement of brown coal generated power in Victoria and trading the surplus renewable energy from the southern regions. The role of Snowy in providing backup for variable renewable energy is expected to increase and the volatility of interconnection flows on a day to day and hourly basis would be expected. Options to enhance the Victorian export capacity would be expected to increase in value as more renewable energy is developed in the southern NEM regions.

Figure 2-6 shows an example of forecast interconnector energy flows among the NEM regions for a medium carbon price and medium demand growth. Under this scenario, the energy flow from Queensland to NSW is relatively stable with some reduction after 2010 as additional renewable energy from the southern regions displaces thermal generation. The flow reverses on Basslink with net exports assuming that hydro yield recovers in Tasmania, Tamar Valley operates at intermediate duty and wind farms are added in Tasmania. These levels of power flow are within the capabilities of these interconnectors without uneconomic constraints. However, the flow between Victoria and South Australia reflects significant constraints for flow to Victoria from about 2017 and in 2010/11. This flow is driven by assumptions in the modelled scenario about the development of geothermal power connected into South Australia from 2015.

[11] Even though the Snowy region has been abolished, it remains useful to think of Snowy to Victoria and Snowy-NSW as interconnectors on aphysical basis.

Figure 2-6 Interconnector energy flows



Planning will need to be expanded to contemplate new regions and new long-distance connections:

- Connection of Mt Isa to Central Queensland may become prospective to lower the costs of energy supply to Mt Isa and to open up renewable energy sources in Western Queensland. It may not be justifiable solely on the benefits for Mt Isa.
- Connection of Moomba to Port Augusta and Adelaide with additional export capacity from South Australia to open up the geothermal resources in Central Australia. It would not be justified solely for the first block of geothermal power which is expected to be about 100 MW.
- Opening up stronger connections to the Eyre Peninsula in South Australia associated with increased export capacity from South Australia. This would enable the wind potential of the Peninsula to be developed. It will be necessary to ensure that the total amount of wind that is connected can be absorbed without deterioration of supply quality or threat to system security. The existing arrangements for this type of analysis are suitable except that major transmission developments should have to consider ultimate wind potential that is economically and technically feasible.

These particular opportunities would need a strategic approach to planning and financial commitment that would involve taking some market risk with respect to the transmission investment if either of these projects were to proceed.

2.8.2 Basslink

Basslink may need to be augmented at some stage to maximise the potential for renewable energy generation in Tasmania which may be in excess of local demand and the ability of the Tasmanian system to absorb the variable generation output. Previously Basslink was developed through Government initiative operating through the state-owned Hydro Tasmania. The addition of a second HVDC cable to Basslink might be difficult through normal commercial means due to the economies of scale problem. The additional 480 MW capacity from a second cable could be difficult to contract in the market unless associated with a large portfolio in some way through ownership of the asset or through long-term contracting of the capacity.

2.8.3 Western Australia

The various systems in Western Australia are likely to remain isolated due to the vast distances relative to the power transfer levels that would be economic. In the SWIS, Western Power is proposing a 330kV line to Geraldton by 2012 which would open up the opportunities for renewable energy from new wind farms. However there remain potential operating difficulties with absorbing large amounts of wind into the SWIS and the Pilbara systems.

2.9 Issues emerging

Recent modelling of emissions trading has examined various emission abatement targets as well as the effect of the 45 TWh RET, as far into the future as 2050. This modelling has indicated a number of potential issues for the energy markets which are outlined in this section.

2.10 Locational Issues

The primary locational issues relate to the retirement of the existing brown coal fired generation capacity in the Latrobe Valley[12] and its replacement by renewable energy from the southern regions of the NEM, gas fired generation in Victoria and black coal fired energy from NSW.

2.10.1 Brown coal generator performance and retirement

- The Victorian brown coal plants gradually become non-viable as the carbon price increases. In market modelling we have retired brown coal plants when their spot and contract revenue no longer recovers their avoidable costs of operation.
- As brown coal units are retired, Victorian spot prices rise slightly unless new entrants are commissioned at the optimal time to replace them.
- The RET scheme mitigates the price rise on the closure of brown coal plants because it stimulates new renewable energy capacity in Tasmania, Victoria and South Australia which have favourable resources to replace them. However, the benefits of resources in South Australia are limited by constraints on export of power from South Australia

12 There is also a 150 MW brown coal generator at Anglesea operated by Alcoa to support the Point Henry aluminium smelter. It would be reasonable to expect that under CPRS the power station will continue to operate until the coal supply is exhausted or the Point Henry smelter closes, as the smelter may be protected as trade-exposed industry. As stated previously, the range of studies indicate that anything from about 2,000 MW to 4,000 MW of existing brown coal capacity will close down over the period from 2011 to 2020.

to Victoria. In some scenarios, it would be viable to upgrade the Heywood interconnection with 500 kV high voltage alternating current (HVAC) or high voltage direct current (HVDC) transmission. MMA has not conducted any detailed studies to verify this perspective.

- The rate of new capacity replacement that is required can be up to 1,000 MW per year which may be difficult to deliver without multiple sites and technologies applied to the task. Existing gas supply infrastructure may need to be expanded to cope with the increased demand for gas for power generation.
- In addition the replacement renewable resources are mostly not controllable base load in operating mode and may therefore require additional back-up reserve power which will be gas fired and impose variable demand on the gas supply system.
- If large amounts of brown coal generating capacity in the Latrobe Valley are not replaced with alternative capacity in the region, the 500 kV transmission system from the Latrobe Valley to Melbourne would become a partially stranded asset. The NEM has not dealt with stranded transmission assets before and this might become the first example. Some of the Latrobe Valley generation could eventually be replaced with new carbon capture and storage power plants based on gas or brown coal, but there may yet be a long period of lower utilisation of the transmission network. The costs of dismantling transmission lines may be high and it would be unlikely to be viable to reuse the 500kV transmission assets on another corridor if no longer required on the current easement. However, it would be desirable to ensure that maximum economic use is not thwarted by any deficiencies in the network service regulatory regime.
- The performance of brown coal generators approaching retirement may decline as maintenance is minimised. Plants may well be run until significant failure because any further capital to maintain operation would have a limited period in which to recover the investment. This means that the measurement of reserve margin to meet the reliability standard may need to recognise this deteriorating performance and reserve capacity may need to be increased.

2.10.2 Black coal generator retirement

- Most of our studies have indicated that for carbon price below \$25/tCO_2e, most black coal plants would not be expected to close before 2020. This gives NSW and Queensland more time to respond to climate change than the southern regions where brown coal's contribution is substantial.
- Coal from Leigh Creek is used in the Northern and Playford power stations, but this coal source will be exhausted by 2017. After 2017, the power stations will either have to be adapted to use lower quality coal, be closed or use imported coal. If they are closed, another 760 MW of capacity will be needed to replace them[13].

[13] The Northern Power Station is 520 MW and the Playford Power Station is 240 MW (gross capacity).

- The NSW black coal plants operated in an intermediate role in the mid 1990s and early 2000s due to the supply surplus that was created when Mt Piper was completed 10 years earlier than needed. The black coal plants are slightly more flexible than the brown coal plants and are more able to adapt to weekly intermediate operation.
- The supply of coal may become more variable as coal moves into intermediate duty on a seasonal and weekly basis. This may have an adverse impact where long-term coal supply contracts are required to secure new fuel supplies. There may be increased value in spot coal purchases but increased risk in the coal mining sector. Inability to obtain a suitable match between supply and demand may advance the retirement of some black coal fired units in NSW and Queensland.
- Black coal retirement in Western Australia is less likely to be a significant issue for some time due to higher gas prices and limited competition in coal supply. Coal supply competes directly with gas for power generation in the SWIS. Due to the lower level of competition in fuel supply in the SWIS, the strong regional growth and the limited scope for connecting large amounts of variable renewable energy, black coal may survive longer in the WEM before major retirements are considered.

2.10.3 Location of new generation – transmission utilisation

- If nuclear power generation were adopted and developed to replace coal fired generators in the Hunter Valley and the Latrobe Valley, then the transmission system may not suffer as much from asset stranding. These locations are remote from major population centres and have access to cooling water and relevant technical and engineering services. Currently, the regulation of transmission services may not fully support new generation locating where spare transmission capacity will emerge in the future. It is acknowledged however that excess transmission capacity can be a locational signal for all new investment. There is potential that existing coal regions could encourage growth in gas-fired generation technologies depending on the nature of complementary investments in associated gas infrastructure such as pipeline capacity and gas storage.
- This issue also applies in regions such as the Latrobe Valley where gas supply is likely to be economic. The energy market frameworks should provide a process to ensure that economic options are not being unduly limited by the pricing structure and cost allocation for transmission services.

2.11 Technology development and barriers to entry

A number of issues relate to the incentives and policies for adoption of new technologies and their development. This relates to the competition between gas, nuclear and geothermal and solar thermal resources for base load generation. The energy market frameworks are specifically designed to be technologically neutral and this is a desirable objective to achieve economic efficiency and to minimise barriers to entry. This section highlights some matters where the energy market frameworks may need to adapt to change in technology.

2.11.1 Distributed energy storage technologies

The role of energy storage may increase if more efficient and lower cost batteries are developed. Eventually, electric vehicles may play a part in real time energy management as they will add to average demand for electricity and could provide peaking power for short periods if part of a smart grid control system. Such operations would be expected to have an impact on the retail market and require more sophisticated trading facilities. The wholesale market in its current form could take aggregate bids for energy storage and peak support. What are missing are the commercial arrangements to install and utilise the integrating technologies that would enable it to work at the wholesale level and to control multiple distributed resources. These commercial arrangements are difficult to establish because of the barriers to planning and trading distributed energy resources. The installation of "smart meters" will facilitate the development of distributed resources.

2.11.2 Nuclear generation policy

One of the apparent issues to come out of the modelling is that if

- gas prices increase rapidly, or
- geothermal does not become viable, or
- carbon capture and storage proves to be costly and limited in scope,

then the case for nuclear power as an option to replace the coal fired power stations may be compelling. The development of large scale nuclear power would have a significant impact on the transmission system and may involve additional inter-regional power flows because an economic site would have at least 3,000 MW made up of 1,000 MW units.

MMA understands that it would take some five years to establish a regulatory regime for nuclear power and another five years to build the first plant. This means that gas fired generation is an essential transition fuel from 2010 to 2020, after which nuclear power could then displace the high cost gas fired generation and remaining coal fired generation.

The NEM market framework would not preclude nuclear power. However the large scale of efficient unit size and the impact on the energy market and the transmission requirements would present some additional planning and trading risks. Co-ordinating transmission for new large scale nuclear power developments NEM wide would be better facilitated by the proposed National Transmission Planner than by TNSPs operating independently. The inter-regional charging arrangements for TUoS would also need to be improved to ensure that the network costs are distributed equitably and efficiently.

2.12 Fuel mix

In the medium term, coal consumption could decline and gas consumption for power generation could increase.

2.12.1 Gas transmission and consumption

The relative cost of gas and coal fired generation will depend on gas prices as well as carbon prices. Higher gas prices would require a higher carbon price for gas to displace coal to achieve a given carbon emission level. The critical switching point for achieving significant emission reductions is when the long-run marginal cost of gas fired combined cycle generation is lower than the short-run marginal cost of coal fired generation including emission costs, irrespective of emission permit allocation.

In the next ten years the rate of consumption of gas for electricity generation could rise from 200 PJ per annum to 600 PJ per annum in the NEM. The range of uncertainty of gas demand for power generation in the NEM based on some recent modelling is shown in Figure 2-7. This will enhance the importance of planning for new gas pipelines and gas supply capability. Substantial investment will be required to develop the new gas supplies. This greater reliance on gas fired generation may mean that some parts of the electricity transmission system would become under-utilised and new transmission will be needed elsewhere.

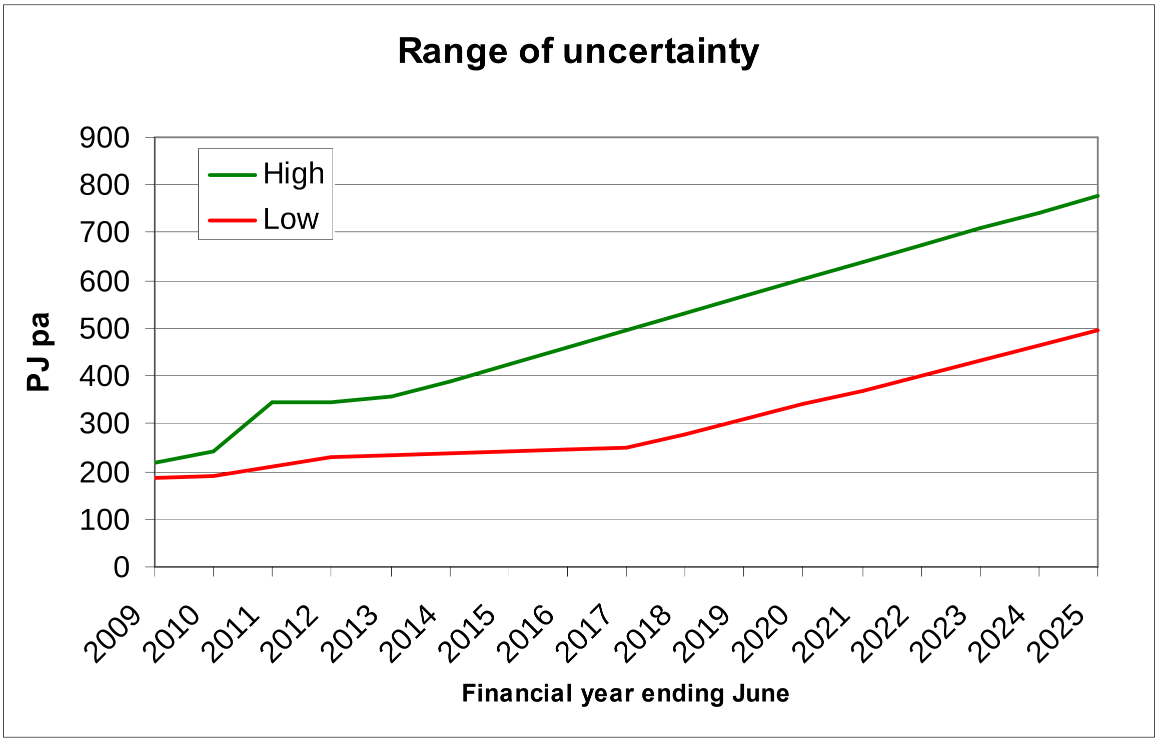
Gas pipeline development would also become an alternative to electricity transmission in some areas where the location of the gas fired power station becomes optional. The question then becomes: should we transport the gas to a power station near the load or the electricity from a remote power station to the load? Some of the need for gas for electricity generation will be partly offset by decreasing demand for gas for other energy uses (industrial heating loads) under a CPRS and eventually lower demand for gas in electricity generation as other low emission technologies dominate the generation mix. This makes long term planning difficult.

Internationalisation of gas prices and the inevitable increase in eastern seaboard gas prices are expected to cause additional increases in the price of gas for power generation and make it more difficult to cause coal generation to be displaced by gas generation in the merit order. Higher gas prices will increase the incentive for some renewable energy where it is available at competitive cost with the higher cost thermal power. It would also reduce the price of Renewable Energy Certificates from what they would otherwise be at lower gas prices.

The demand for gas for electricity generation may become more volatile where gas fired generation is supporting other variable generation resources from solar and wind resources. This may require changes to gas markets to improve the efficiency of day to day production and transport with volatile demand. There may also be increased demand for gas storage and LNG storage to manage peak day demand uncertainty. The gas markets may need to be able to transact infrequent use of LNG to manage supply security issues.

There may also be increased demand for distillate fired generation to provide security where there is a risk of gas transport constraints and disruptions. The increased use of gas in electricity generation will increase the economic impact of interruptions to the gas supply.

Figure 2-7 Range of demand of gas for power generation for the NEM



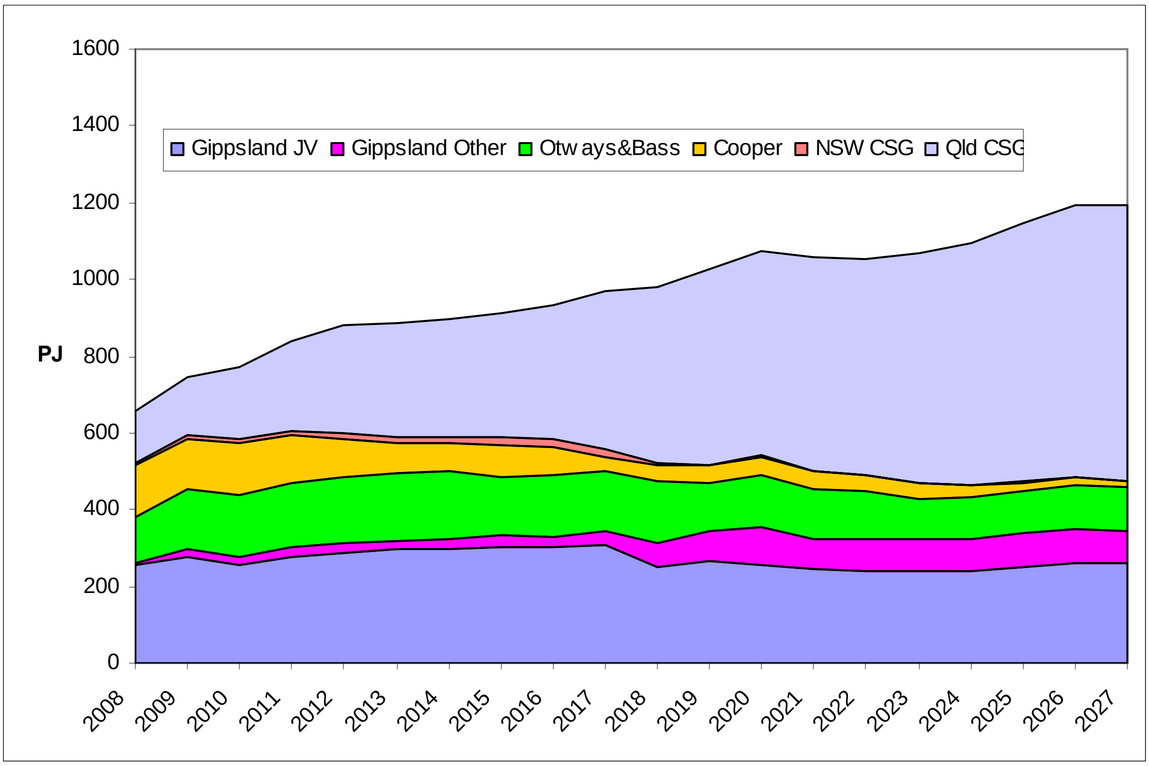
Source: MMA analysis

Long-term gas contracting may become more difficult as the Bass Strait and Cooper Basin fields become depleted. Figure 2-8 shows an example of the projected utilisation of gas sources to 2030 excluding any major demand for LNG. In this example, Cooper Basin is in decline and Bass Strait production levels out until about 2017 when it falls away. Attempting to obtain a fifteen year supply contract for a new gas fired power station when there is only eight to ten years of production life in a field becomes a significant problem for either the buyer or the seller. This challenge is unlikely to be mitigated without changes to energy market frameworks that provide a more dynamic trading environment for natural gas, although the STTM can provide some of this service. It would be expected that reliance on long-term bilateral supply contracts would limit the amount of gas that is committed to long-term base load generation.

2.12.2 Role of hydro and gas turbines to provide energy reserve

One of the important roles of hydro power generation in the NEM has been to provide short-term energy reserves during base load plant outages. With the reduced relative size of the hydro resources, the increasing uncertainty about future rainfall in hydro power catchment areas and the impact of water supply on thermal generation, this role has been increasingly taken over by the gas turbine plants. With increasing contributions from wind, the energy reserve role will increase beyond the capability of the hydro system and the NEM will be dependent on gas fired generation to make up for the lost wind contribution.

Figure 2-8 A gas production scenario forecast (excluding LNG)



Source: MMA analysis

Wind power may not significantly displace coal, except in NSW and Queensland in the medium term. In the southern regions, wind power displaces gas fired generation in the absence of a carbon price. As the carbon price increases the displacement would move to the coal plant and the duty of gas fired generation would increase.

Therefore, the increasing volumes of wind power would create more day to day variation in the demand for gas for power generation. It is unclear if the gas markets are prepared for this trend. The value of gas storage may therefore be increased as a result of the increasing wind generation.

2.13 Transmission planning and development

2.13.1 Transmission from remote areas

The current market arrangements assume that economies of scale in generation and transmission are no longer significant. This may not be as true if there are major shifts in the location of base load generation away from fossil fuel centres to renewable energy centres. Additional transmission lines may be required to capture remotely located renewable energy such as in north-west Tasmania, the Eyre Peninsula in South Australia, the geothermal zones in South Australia (such as Moomba) and the western areas of NSW and Queensland where solar energy is abundant. For transmission over distances exceeding 800 km, HVDC transmission is more economic than conventional HVAC transmission. The economic scale over such distances would exceed 500 MW and could be typically up to 800 MW with voltage up to 500 kV and current up to 1,600 amps. By way of comparison, Basslink operates at 400 kV up to 1,575 amps for short periods.

No individual generator could likely sponsor an efficient transmission line and no efficient transmission line could pass the regulatory test as it is currently implemented, because the prospective future generation is too speculative. Dealings with economies of scale in transmission with many and diverse renewable energy projects would be difficult under current arrangements. For example, it is difficult to see how the first 100 MW remote geothermal plant could connect to the grid over 800 km away using an 800 MW capacity link, even if the potential future generating capacity is matched to the 800 MW transmission line capacity.

The network planning arrangements will need to be amended to better deal with the uncertainties in the evolution of technologies and project development in order to provide the facilities to connect the lowest cost energy resources in a timely manner.

One potential solution to the funding of strategic transmission projects to unlock lower cost renewable energy resources might be to use the proceeds of carbon permit sales to fund the developments until the generation transfers would be sufficient to fund the asset. However, this is not solely a matter for the energy market frameworks, but also could be an element of the CPRS itself[14]. Initial funding for such strategic transmission investments could be made up of four components:

- An initial contribution from the remote generators, which increases as their projects become commercial and which reflects a reasonably shallow connection contribution that is consistent with the treatment for incumbent remote generation. It would represent payment of an option fee to gain access to greater capacity if needed subsequently.
- A component from the regulated TUOS charges that is commensurate with the prevailing market value to customers. This would progressively increase over time as the transmission asset is utilised.
- Government funding that is related to infrastructure development quite apart from CPRS imperatives.

14 Governments could fund such investments and part of national infrastructure development. This option seems to be unnecessary given that the energy market and the CPRS already have the frameworks to raise funds from participants that are commensurate with the value created. However, there may be a substantial call on CPRS revenues in the early phases to ease the transition and direct Government funding of some transmission projects might be needed to achieve the necessary developments.

- A balancing component which makes up the gap between funding cost and the foregoing revenue sources. This could be funded by revenue from the sale of permits under the CPRS during the transition phase and would eventually decline to zero unless it turns out that the planning basis proves to have been too optimistic.

2.13.2 Transmission development in a low growth environment

One of the likely impacts of CPRS is to encourage greater energy efficiency and to cause some energy consumption activities to cease altogether. If this is combined with reduced economic growth generally, then some parts of the network may experience very low growth but with remaining constraints. Due to the economies of scale in transmission and distribution, a low and uncertain growth environment is problematic. It is very risky to add large scale capacity that may not be needed for a long period of time if growth ceases or regresses. Accordingly, preferred options become demand side management and local generation, even at a higher average cost than the transmission asset, because they may be able to be redeployed or retired if no longer needed. An example of this was the development of Bairnsdale Power Station in Victoria to defer the need for the Bairnsdale 220/66kV terminal station and the associated 220kV line from Morwell. This was originally planned for the mid 1980s but has not yet been needed due to low growth in eastern Victoria and the good performance of the Bairnsdale Power Station.

Thus CPRS will increase the scope for demand side management and distributed generation to defer transmission and distribution investments where the market is stable and growth is low and uncertain. Network planning procedures will need to be improved so that useful information is published on the value of distributed generation and demand side response so that investors can be prepared to bring suitable projects forward in the optimal locations.

MMA has advised on this issue in the review of the arrangements for the National Transmission Planner[15]. The MMA paper proposed the concept of a Value Function that describes the drivers for the economic value of a proposed investment in terms of localised generation capacity, peak demand or other factors.

2.14 Operational matters

There are also a number of operational issues affecting gas and electricity which have not specifically arisen in terms of MMA's modelling studies, but which are nonetheless worthy of consideration in the context of this report. These comments are based upon MMA's knowledge of the electricity market and market operations generally.

15 http://www.aemc.gov.au/pdfs/reviews/National%20Transmission%20Planner/draft% provides a discussion of the concept of a Value Function which provides market participants with economic information about the determining factors for the proposed network project. This would be used to identify the best location for demand side response and embedded generation.

2.14.1 Brown coal operations

If brown coal plants move from base load to intermediate duty on a seasonal, weekly or daily basis, then the high start-up risks and costs may be difficult to manage when the plant is operating in a dynamic environment with other variable generator contributions. Not only will operating costs increase, but so would dispatch risks. It may be worth considering whether the market dispatch process might need to consider start-up bids and centrally optimise unit commitment rather then rely on self-commitment, as does the current market design. The value of such a process would be enhanced if the process for self-commitment proves too difficult in a market situation with many variable generation resources.

2.14.2 Gas transport operations

The increasing role of gas fired generation in providing energy reserves to cover for the absence of variable generation sources means that gas transport volumes may vary day to day across pipelines and from supply sources. This would increase the value of day ahead gas demand contracting and better management of line pack and gas storage facilities. It is expected that developments in the Short Term Trading Market (STTM), the Gas Bulletin Board, and the Victorian gas wholesale market will improve the industry's ability to manage this change.

2.14.3 Electricity market operations and design

The design and implementation of market infrastructure is generally based on the operational realities affecting market participants, requiring consistency with the mechanics of associated contracts, organisational structures and market assets. It is reasonable to assume that the major structural transformation that will result from the implementation of CPRS/RET policies, will require some adjustment to the market design. Examples of potential change requirements include the following.

2.14.3.1 Day ahead contract market

An increased reliance on gas-fired generation, as well as the likelihood that demand management may be used as a transition strategy to smooth inconsistencies between plant retirement and new investment, may combine to make day-ahead contractual arrangements an increasingly important feature affecting market operation and participant decisions. Examples of such include day-ahead gas nominations, day-ahead load-shedding negotiations, and other bilateral contracts that may require coordinated planning in advance of the trading day.

This changed dynamic environment for the electricity market may enhance the value of a day-ahead market as originally proposed for the NEM, or in manner similar to this feature in the Federal Energy Regulatory Commission's Standard Market Design. Such an arrangement could provide greater financial certainty to market participants and assist efficiency in the management of contractual arrangements. This idea has been implemented in the SWIS as the Short Term Electricity Market. Variable generators would be better able to contract some of their output directly into the market in the long-term if they could cover their position in the short term based on generation forecasts up to several days ahead. The current market arrangements make this difficult, because daily trading is illiquid. Variable generators have to sell their output into a large portfolio which can manage the day to day variability. This would normally provide better value than relying solely on the spot market.

2.14.3.2 Optimised unit commitment

The NEM market design currently features generator self-commitment, requiring generation participants to determine when their units are on and off. The likelihood that formerly base-load coal-fired generators will move up the merit order as a consequence of the CPRS, will add complexity to unit commitment decisions. Affected units may become mid-merit generators, two-shifting within the daily dispatch. Constraints affecting ramping, minimum on and off times and start-up and shut-down curves will become important in managing the physical heat states of boilers, and therefore the availability of units. Start-up costs of these units can be very substantial, upwards of tens of thousands of dollars for some technologies. These costs can add a very large increment to average MWh generation costs when the contiguous periods of generation are limited to hours rather than days. Moreover, should units be scheduled off at night, start-up constraints may prevent their ability to supply a subsequent morning load.

Participants may find it increasingly difficult to determine unit commitment, potentially leading to far higher bid prices as a means of managing opportunity costs associated with shutdown, slow start-up, start-up costs and short operating periods. It is expected that a move to optimised unit commitment within the market scheduling software could be required to avoid high and volatile price outcomes from self-commitment.

2.14.3.3 Extended optimisation horizon

The market scheduling software currently optimises over the period of the trading day. Given a potential need for optimised unit commitment (see 2.14.3.2), and the reality that formerly base-load coal units may move up the merit order, the optimisation horizon of the software may require a look-ahead period into the next day to ensure that units that may be needed for a subsequent morning peak, are not shut-down at night, or otherwise not at full availability early in the next trading day when they may be needed.

2.14.3.4 Additional commercial and technical offer constraints and altered pricing logic

The realities of formerly base-load plants becoming mid-merit will present further challenges to participants in managing change of state operations and costs. Participants may require functionality to bid complex start-up and shut-down curves, start-up and shut-down times, minimum on and off times, and start-up costs. This functionality may require sensitivity to the warmth state of boilers, affecting time and cost parameters. Previously this has not been critical in the NEM because there has been a reasonable match between the various types of power plants and the loading patterns in the demand curve.

Unit start-up costs of old steamers can be very substantial, upwards of tens of thousands of dollars for some technologies. These costs can add a very large increment to average MWh generation costs when the contiguous periods of generation are limited to hours rather than days. Uncertainty in the duration of scheduled generation may require a large risk component added to bids to ensure that start-up costs are recovered if scheduled for only short periods; a coal plant near retirement may not know, for example, whether it should set its bids to recover a $150,000 start-up cost over 4 hours, 6 hours or 8 hours, each having a significant impact on the required offer price, and introducing an efficiency risk of cost over-recovery if the unit is needed for longer than expected. The market design may warrant review to explicitly accommodate the bidding of start-up costs, with a consequent adjustment to the pricing logic to separately factor start-up costs over contiguous operating periods.

2.14.3.5 Fixed cost recovery and energy market pricing

Participants currently set bids to recover variable and fixed costs. A period of structural change causing shifts in retirement dates and the movement of coal units up the merit order will introduce a dynamic feature of declining capacity factors for formerly base-load units. Declining capacity factors require units to recover what can be very high fixed costs over shorter periods, thereby increasing the fixed cost recovery component of bids over time. Any uncertainty over this dynamic pattern will increase risks requiring an additional fixed cost margin in bids. This could cause extreme price volatility as the market moves towards the thresholds of coal unit retirements, and would raise market monitoring problems regarding assumed capacity factors, and reasonable fixed cost recovery. It could also cause problems with the under recovery of fixed costs for some units that may be needed for reliability, and may also produce prices that give an extra-normal return to other lower-cost units.

It is possible that the NEM could require augmentation with a capacity market mechanism, perhaps during the CPRS transitional period, to separately recover fixed costs, and to reduce price levels and volatility affecting the energy market if there is evidence of inefficient bidding behaviour due to uncertain market dynamics in the spot market.

2.15 Energy trading

2.15.1 Doubling counting emission abatement cost

The cost of Renewable Energy Certificates (RECs) represents the difference between the cost of renewable energy and the value of the energy in the wholesale market. Ideally, this will eventually go to zero as renewable energy costs fall faster than thermal energy costs as fossil fuels are depleted or as carbon costs increase. The flow through of carbon prices into the energy costs will mean that REC prices should fall as carbon price rises with the flow on to energy prices based on the marginal resource that sets the energy market price. If the transactions concerning RECs do not reflect the impact of carbon price, there would be a risk that some parties may pay twice for emission abatement: once through the REC price and then again through the energy price as carbon price increases. This double impact would be avoided if REC prices are carbon price reflective.

This unclear exposure to carbon and REC cost will limit the transaction options for retailers seeking to meet their obligations. If the retailer purchases RECs and energy separately they may be exposed to double counting unless there is a reference carbon cost. This cost separation is sometimes referred to as the black/green energy categories. The black energy cost excludes the impact of the renewable energy target but does already include some emission abatement impact through the wholesale market since the presence of traded products such as NGACs and GECs has the effect of reducing energy prices in the spot market. The green energy component usually refers to the additional cost of supplying renewable energy as reflected in the REC price. It would be expected that the black energy price will include the effect of the carbon cost and it may not be practicable to separate out the carbon component except by using some standard measure, similar to the NSW pool coefficient in the NGAS. For trading purposes, some reference carbon price that can be used to adjust REC prices would be beneficial in reducing trading risks and improving liquidity in derivative energy and emission abatement products.

This risk of double counting is manifest in market participants struggling to identify a basis to adjust contract prices according to carbon price. Whilst the future carbon price remains uncertain, generators will require some measure for pass-through of carbon price so that the strike price in their contracts can adapt to their carbon costs. It would be the same situation if generators faced a highly uncertain fuel price.

2.16 Critical issues

From this analysis, the critical issues are:

- Uncertainty about the technological transformation that will result from CPRS and RET. What will be the location and magnitude of the new generation resources that will be developed?
- The retirement of coal-fired plant and how that would affect the drivers for new entry and supply reliability. Will supply reliability be maintained?
- Commitment to build new capacity when future revenues and costs are so uncertain. Can allocative efficiency be maintained through the investment cycle when the future is so uncertain?
- Transmission for new distributed generation resources. How will the commitment be made to build enabling transmission services when the associated generation facilities are not yet financially committed but have substantial potential?
- Will adequate reserve margins and reliability be maintained if plant performance is deteriorating and there is a disincentive for new plant investment because uncertainty delays immediate commitment?

2.17 Threats to energy market objectives

The critical issues for energy services relate to reliability, security and efficiency. These are the foundation of the energy market objectives. A consideration of the market issues in relation to meeting the market objectives is summarised in Table 2-2.

Table 2-2 Relationship between wholesale market issues and objectives

Market objectives ► **Market factors ▼**	**Reliability**	**Security**	**Efficiency**	**Comments**
General sense of market uncertainty.	Failure to invest in new capacity in a timely manner.	System constraints could increase due to delayed investment.	Delayed investment in new lower cost and lower emission resources. Higher cost of capital to the market.	This item describes a malaise that could have wide ranging and unpredictable impacts.
Coal plant retirement.	Failure to invest in replacement capacity in a timely manner.		Prices could well exceed new entry costs if new entry is constrained. If this did not accelerate new entry then substantial inefficiencies would occur.	This is a major contributor to reducing carbon emissions and will have a high profile in CPRS.
Coal plant performance before retirement.	Reserve margin could be under-stated if decline in performance is under-estimated.		Whilst it may be efficient to no longer maintain the plant to the same standard, the level of maintenance would be sub-economic to the extent that market power is substantial.	Plant retirement programs could enhance market power of incumbents if supply margins become tight.
Transmission development may hinder connection of new resources.	Undermined by inter-regional constraints and under-utilised resources.		Higher cost renewable energy resources developed because lower cost resources cannot gain connection and transmission service.	Economies of scale in new 500 kV HVAC and HVDC transmission may be a barrier.

Market objectives ► **Market factors ▼**	**Reliability**	**Security**	**Efficiency**	**Comments**
Caution in commitment to new capacity.	May be undermined if new capacity is deferred.	Increased exposure to market disruptions from low reserves and poorly performing plant.	Delayed commitment to new capacity may not be efficient.	Reserve Trader (RERT) activities may need to be strengthened to manage this risk effectively.
Mismatch between the plant mix and the system load profile as affected by variable and distributed energy sources.	Could invalidate the current methods for assessing unserved energy risk and appropriate reserve margins for operating and planning purposes. Risk of lower system reliability.	Self-managed unit commitment may not be optimal to achieve adequate system security.	Self-managed unit commitment may impose unnecessary operating costs when dealing with variable generation and gas supply.	May require more decisions to be centrally dispatched based on cost based bids. Need to reformulate the reliability standard.
Increasingly variable gas demand for power generation.	No major consequence providing there is sufficient back-up liquid fuel operation should gas supply become restricted.	Increasing exposure of energy markets generally to large scale gas transportation infrastructure.	The costs of managing variable gas demand may increase unless more sophisticated market mechanisms are introduced.	The current project to review the gas trading arrangements in Sydney and Adelaide would be expected to address this issue.

The CPRS and RET may impact on reliability and efficiency in achieving the stated targets of the energy markets and the climate change policies if market participants perceive excessive market risk and do not invest for the long-term outcomes because they cannot reasonably evaluate their options and risks. If this becomes a serious threat, then it may be necessary to provide the energy markets with additional guidance and support during the transition phase to manage investment and operating risk.

2.18 Impact of uncertainty

Market modelling can help to identify the relative importance of different factors on outcomes, but with the current state of knowledge the absolute value of quantitative outcomes cannot be guaranteed. There remains considerable uncertainty about:

- the level of carbon prices and the extent and impact of international linkages on carbon prices
- the impact of the higher prices on demand growth and its effect on different types of customers
- the future costs of existing and emerging power generation and energy storage technologies
- the rate of technological change and real cost reduction in the emerging technologies
- the behaviour of market participants adversely affected by carbon prices and climate change generally
- the future mix and location of renewable energy resources
- the impact on the development of the high voltage transmission system.

3 CHALLENGES FOR THE ENERGY MARKET FRAMEWORKS

The previous section of this report provided a summary of our past CPRS/RET modelling and analysis. This summary was developed from a number of advisory reports that assumed a relatively smooth process of change, based on likely behaviour and intuitively reasonable assumptions. Accordingly, it presents an indication of expected market outcomes and participant responses given the assumed form of policy implementation.

In a context of significant policy change however, there is a potential for unexpected outcomes or uncertainties to challenge the smooth functioning of an industry, thereby causing distortions that may upset the way the industry evolves.

The energy market frameworks are required to work and remain resilient in an environment of:

- Unprecedented rapidly rising prices for consumers – with uncertainty about future demand.
- Deteriorating business conditions for high emission generation – with uncertainty about economic life and viability of incumbent's assets.
- Considerable uncertainty for investors – with difficulty in forecasting revenues and carbon emission related costs.
- New planning requirements - with changing roles for particular generation and network assets.

This chapter summarises a number of plausible challenges that could cause market outcomes to change relative to what has been predicted by the modelling and analysis undertaken to date. Given that the energy market frameworks will need to accommodate a range of potential policy impact scenarios, these challenges, albeit unlikely in most respects, may require further consideration as part of the current review of the adequacy of energy market frameworks.

3.1 Regulatory resilience

The task facing the AEMC requires a broad consideration of the potential scenarios and assumptions surrounding the implementation of the CPRS/RET policies. Indeed, the terms of reference provided by the Ministerial Council on Energy (MCE) directs the AEMC to identify any amendments to the energy market frameworks which may be necessary, having regard to the NEL and NGL objectives, as a consequence of, or in conjunction with, the implementation of CPRS/RET policies. These objectives relate to concepts of reliability, security and economic efficiency.

A review of this nature requires the explicit consideration of resilience, as provided by the regulatory and institutional arrangements that together will manage the implementation of industry reform. Resilience refers to the intrinsic ability of the regulatory and institutional arrangements in managing a broad range of potential and plausible industry scenarios. It refers to the extent of robustness to cope with shocks or unanticipated events that could test the ongoing achievement of industry objectives. Scenarios feeding into a regulatory resilience assessment include many that are unlikely, but for which responsible continuity planning depend. Indeed, current industry arrangements anticipate numerous unlikely shocks and scenarios, including participant insolvency, market systems failure and other system and market emergencies.

Based on modelling of potential impacts, the CPRS and possibly expanded RET could result in industry adjustment that has not been witnessed in recent times. MMA analysis suggests that in some cases, some 15% of current installed generation capacity may retire by the year 2025. Associated with this retirement could be geographic shifts in generation centres, away from coal deposits towards smaller and more disparate localities where wind, other renewable energy or gas resources may be present. These shifts may be incompatible with the current configuration of transmission system infrastructure, and require a step change in investment. The institutional capacity to deal with this rate of change is unproven.

Traditional market and industry development processes have anticipated more gradual and incremental change in directions consistent with past performance. The background premise of traditional planning processes, for example, has sought to maintain reliability standards in the context of ongoing demand growth and a forecast of required incremental new generation that is weighted in favour of thermal plant. The introduction of the CPRS and the enhanced RET will likely lead to the early retirement of coal fired plant, and a greater reliance on gas and variable generation. Growth in demand may also stall or significantly slow as a consequence. The extent of change that is implicit with the implementation of CPRS/RET policies may challenge the ability of current arrangements to maintain the delivery of policy objectives.

3.2 Potential challenges for the energy market frameworks

The following summarises a number of general concerns that could challenge the adequacy of the energy market frameworks in facilitating a smooth implementation of CPRS/RET policies. Many of the possible events related to these concerns are considered unlikely, but nonetheless sufficiently plausible to warrant a review to be sure that the energy market frameworks are robust, thereby maintaining market confidence during a period of significant structural change.

3.2.1 Uneven retirement and investment

The successful implementation of the CPRS/RET policies will require an ongoing consistency between patterns of new investment and the anticipated retirement of coal units. Problems affecting this pattern may result in excessive price volatility in the wholesale and retail markets, and may give rise to reliability concerns. The interconnectedness of the energy markets means that investment patterns will require consistency between assets such as generation, gas and electricity transmission infrastructure, gas storage, and other substitutes such as demand management schemes.

The timing of a new investment is in part dependent on the extent that market prices can provide a sufficient rate of return on capital expenditure. The implementation of industry reform can raise investment risks, thereby raising the required return on industry investments, and causing investments to be delayed until expected market prices rise sufficiently to cover the increased risk[16]. Figure 3-1 illustrates how changes in required rate of return as reflected in the weighted average cost of capital (WACC) can affect the timing of new entry. This indicates that higher risk leads to later commitment to new entry and potential for lower reliability of service.

The energy market frameworks assume, and plan for, a general timing consistency in the rate of new generation investment with:

- the rate of plant retirement;
- growth in demand;
- innovation in supply and demand-side technologies and services; and
- the level and pattern of transmission system investment to deliver efficient and reliable power flows over time.

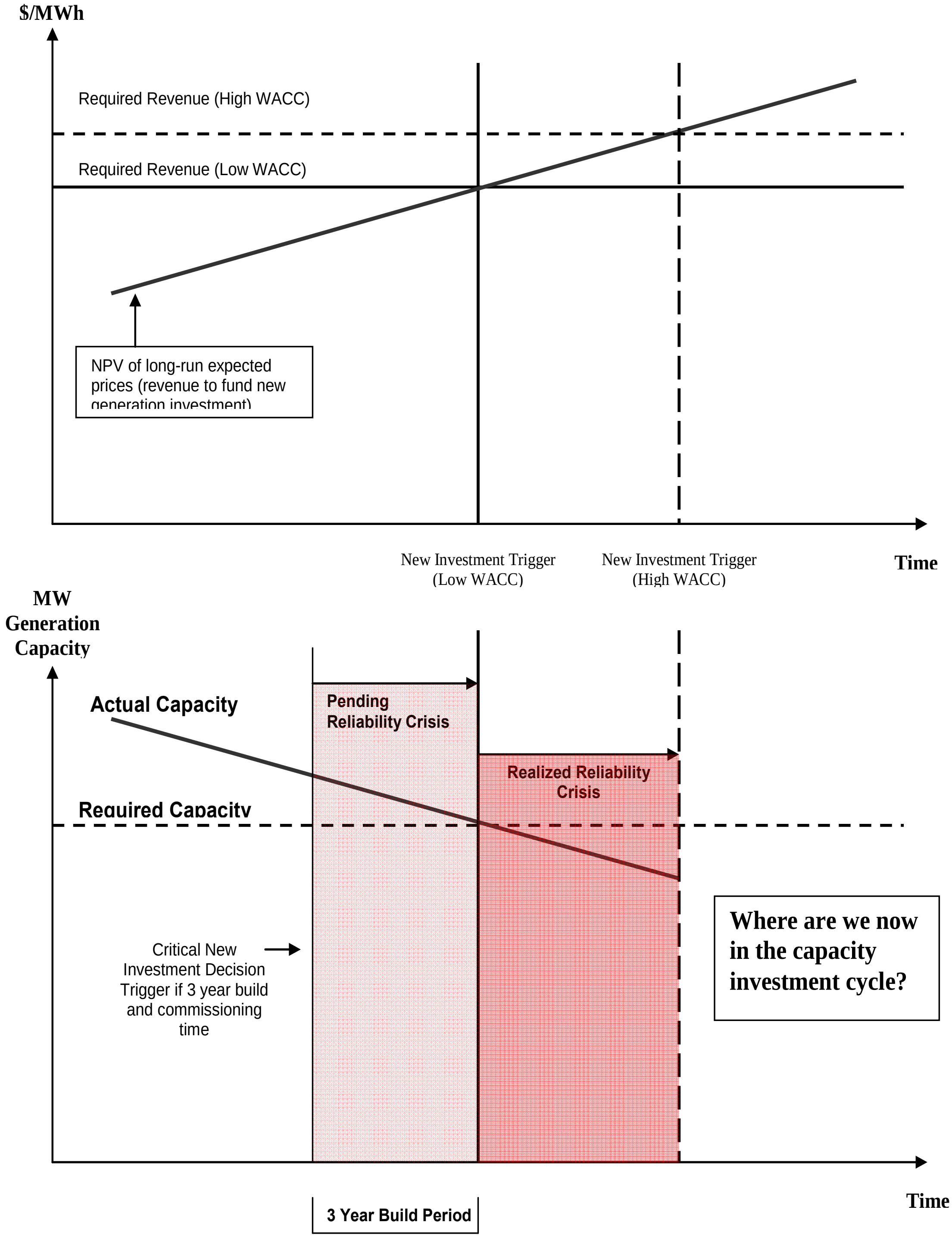
This assumption will be tested with the early retirement of existing plant. Traditional transmission planning approaches may have difficulty coordinating a large step change in investment to provide for new generation in different regions around gas pipelines and areas of higher value wind resources. Anticipated price changes could challenge traditional demand forecasting assumptions, and retail market customer protection arrangements may change patterns of innovation.

Early retirement of generating plant could reduce competition and strengthen the dominant portfolios. They may further improve their financial position by delaying efficient development to the extent that other parties are also hesitant to proceed with new investment.

Regulatory and market uncertainty surrounding the extent of change that must occur could raise the required hurdle rates that trigger investment decisions. An increase of 5% in the pre-tax WACC required for new generation investment could add a 1 to 2 year investment lag to typical build and commissioning schedules for both base-load and peak-load gas plants. Higher WACC would imply that the economic unserved energy level is also higher which should then raise the threshold for Reliability and Emergency Reserve Trader intervention. However, since the higher WACC would be driven by perception of uncertainty rather than fundamental economic costs, it may be preferable for AEMO on

16 See Appendix A, Section A.2 for a discussion of the drivers of risk, a form of "transaction costs." In the case of investment risks, key drivers of WACC include uncertainty surrounding the future competitive market, regulatory and technological environment within which the players will be operating, and the problems of getting players in adjacent stages of the energy value chain to coordinate their investment programs.

Figure 3-1 Illustration of impact of higher WACC on timing



behalf of customers to use the RERT role to secure investment, thereby lower risk and remove the driver of the higher WACC. The disadvantage of market intervention in this manner is the increased risk of excess capacity but this may be considered acceptable where the probability of capacity deficits is greater.

Delays in transmission system investments may cause critical congestion zones between new generation centres and existing load regions, affecting the deliverability of new generation, thereby constraining the ability of these units to fully realise resultant price outcomes. In fact, planning for new generation may be deferred until appropriate commitments are made to expanding the network into the areas where lower cost renewable energy is available.

Observations and suggestions for further analysis or review

While delayed investment due to an increase in required hurdle rates does not necessarily represent a failure in the energy market frameworks, it does suggest the need to review functionality to ensure potential reliability problems can be managed, and it also suggests that should existing levels of reliability head-room be deemed insufficient to cover uncertainty and risk, stand-by functionality may need to be developed if it turns out that current arrangements do not provide the flexibility necessary to manage the effects of investment delay.

Potentially affected functionality in the energy market frameworks includes:

- The basis for setting the minimum unserved energy. Greater uncertainty would justify a lower minimum on an economic basis because the probability of failure is higher.
- The basis for setting the minimum level of unserved energy must have regard to the change in supply mix and its variable and uncertain components.
- The calculation of reserve margin would also reflect the uncertainties of investment and generating plant performance as well as peak demand uncertainty.
- The role and scope of the Reliability and Emergency Reserve Trader in the NEM.
- The formulation of the reserve capacity requirement in the SWIS.

Since higher levels of WACC would be driven by a perception of uncertainty rather than a change in fundamental economic costs, it may be desirable for AEMO on behalf of customers to use the Reliability and Emergency Reserve Trader role to secure investment, thereby lowering risk and removing the driver of the higher WACC. The disadvantage of market intervention in this manner is the increased risk of excess capacity but this may be considered acceptable if the probability of capacity deficit is greater.

There may be benefit in a review of the reliability standard to identify changes that better reflect the cost of reserve plant, opportunities in demand-side response, uncertainties in thermal plant performance, the impact of expected patterns of variable generation and the uncertainty in demand growth following the CPRS and RET price changes. This may require an increase in the reserve margin, setting it in part as a function of lead time, thereby providing for a comparison of the projects that are in various phases of development: notional projects, preliminary planning, environmental approval, advanced planning, and financially committed.

A reformulation of the reserve capacity calculation may be of benefit, to include the effect of the evolution of growth and plant performance uncertainties over at least a five year horizon. This revised reserve capacity measurement would provide the basis for longer term risk assessment and possible intervention of the Reliability and Emergency Reserve Trader to stimulate activity in the development pipeline.

Power flow and deliverability modelling could be undertaken to assess the transitional capacity of emergent generation regions to meet load requirements in traditional demand centres. Substantial upgrading of interconnections or supplementary HVDC links may be needed to maintain performance of the transmission system with new remote generation sources with low inertia.

There may also be some benefit in a review of critical new investment thresholds to assess the reliability head-room that currently exists, and to determine critical dates beyond which market intervention may be warranted if commitments are not apparent by a specified time.

3.2.2 The possibility of greater than expected price and settlements volatility

MMA has identified a number of factors that could increase the volatility of price and settlement outcomes in the markets affected by the energy market frameworks. In some situations, this increase in volatility could become large, potentially affecting the smooth transition of the industry in response to CPRS/RET policies. Some of these factors include:

- Uneven retirement and investment (see the previous section), causing scarcity price effects related to gas supply, pipeline capacity, gas storage capacity, transmission capacity, water availability, and constrained-off generation.
- Operational inflexibilities in the market design (see Section 2.14.3 for a discussion of issues related to fixed cost recovery, unit commitment and the adequacy of technical and commercial offer constraints).
- Uncertainty margins in contract pricing, and constrained capacity market liquidity (see section 4.1.1.1).
- Potential competition issues that may arise if early plant retirements cause some suppliers to become pivotal in the dispatch (see section 4.1.1.2), or in the case of gas, if the combination of gas demand growth and infrastructure capacity constraints provide certain portfolios with an ability to influence price and settlement outcomes.
- Emerging transmission constraints and load pockets causing out-of-merit dispatch in the operational schedules of the gas and electricity markets, causing price and uplift effects.

Increasing interconnectedness between the gas, electricity and to a certain extent the water markets means that volatility issues in one market can be readily transferred to other markets, therefore increasing the likelihood and extent that scarcity events may change price outcomes.

The significant structural transformation that will be required of physical infrastructure may give rise to a large increase in the number of contingency projects that could be approved within the regulated pricing processes of the transmission and distribution sectors. This could translate into significant retail price volatility and contract resets.

Observations and suggestions for further analysis or review

Unexpected changes in price and settlements volatility may require markets to adapt risk management mechanisms such as credit and prudential controls, physical and financial hedging limits and trading limits. It may also require contracts to be adjusted or reset. While market arrangements are generally resilient to shifts in volatility levels, there is a risk that cumulative structural shocks to the markets may compound in a manner that cannot be managed smoothly within a context of change to market and institutional function.

The industry could benefit from further market modelling to test the resilience of market arrangements to various events that could give rise to increased price and settlements volatility, thereby assessing how far the market can be pushed before arrangements require adjustment. Key areas that could be assessed include the effect of early retirements, variations in investment timing, and portfolio based pivotal supplier analysis.

3.2.3 Retail price paths may not allow full cost pass-through

The CPRS/RET policies will necessarily raise wholesale market prices, as well as price volatility in the event of delays to investment. In some situations this could become extreme, particularly as the market approaches the retirement thresholds of large generating plants; in this case the commercial imperative for fixed cost recovery combined with falling capacity factors could push the bid prices of required plants to high levels.

MMA analysis suggests that wholesale market prices will follow a pattern of progressive increases as carbon price increases and marginal coal units retire, in each instance removing a large increment of installed generation capacity from the market supply curve. Even under likely implementation scenarios, this will cause a degree of volatility that will need to be managed via longer-term retail supply contracts and default or regulated tariffs.

Observations and suggestions for further analysis or review

Wholesale market price volatility, combined with increased investment cost recovery in the transmission and distribution sectors, may cause concerns for the retail market. It is possible that full and timely cost recovery via retail prices may not be acceptable within some state jurisdictions, increasing pressure for transitional retail price controls and a tightening of customer protection arrangements. This would increase the likelihood that cross-subsidies will be forced onto affected retailers, other customers, and counter-parties to upstream transactions.

Limitations on the distribution of these cross-subsidies could cause affected retailers to experience financial stress. It also introduces other distortions affecting both the gas and electricity markets.

There may be benefit in a review of communication and coordinative processes between the multiple regulatory jurisdictions to ensure that these processes can appropriately anticipate and manage potential retail sector constraints.

Of further benefit is a survey of potential investment requirements to understand whether transitional debt funding provisions may be needed to carry significant investment costs that may be beyond the near-term price paths that are acceptable to end-users. This would be integrated with the implementation of CPRS and its compensation and transitional arrangements.

3.2.4 Regulatory inconsistencies between Markets and Jurisdictions

The implementation of a national energy market framework ultimately relies on a suite of associated arrangements at the State level, and provides scope for the States to negotiate derogations from some national regulatory and legislative provisions. Indeed, National Electricity Law is effected via state level legislation, and the States and Territories retain related power over areas such as retail pricing, licensing, safety and other codes and arrangements. The success of the energy market frameworks and of related national objectives therefore depends in part on response of adjacent and related jurisdictions.

Similarly, the electricity and gas industries are coordinated via distinct wholesale and retail market arrangements and they relate in complex ways between each other, and with other related markets such as financial markets, water markets, generation fuel markets, and markets for infrastructure investment and management.

It follows that reform targeted at a particular aspect of the energy market frameworks may have complex reverberations across related markets and jurisdictions.

Observations and suggestions for further analysis or review

Contradictory regulatory responses at the state level or in related markets may undermine the implementation of the CPRS/RET policies, forcing excessive distortion onto certain customer segments, market participants and related markets or regions.

Communication and reform implementation arrangements could be reviewed to ensure that all affected jurisdictions and markets participate in reform efforts, and that each are appropriately consulted in advance of market changes to ensure a smooth and coordinated process of reform.

3.2.5 Asymmetry of information

The structural changes implied by the CPRS/RET policies will require a change in decision-making, affecting market operation, system planning and strategies relating to contracting, maintenance, retirement, bidding and investment. Many of these decisions will rely on private information about opportunities, risks, asset condition and market expectations.

Observations and suggestions for further analysis or review

Asymmetrical information could significantly distort market function. Critical areas relate to planning, contracting and market monitoring, each reliant on the behavioural assumptions of other market participants.

The industry could benefit from a review of critical information that is needed to facilitate the anticipated structural changes resultant from CPRS/RET policies, and an assessment of the information provisions that currently reside within the energy market frameworks to assess whether a strengthening of arrangements may be necessary.

Information provisions regarding the costs and benefits of proposed network investments could be enhanced to better facilitate long term planning for embedded distributed generation and demand side response. This could be included in the Annual Planning Reviews based on scenarios provided by the National Transmission Development Plan.

3.2.6 Emergency response and management processes

The energy market frameworks anticipate a range of extreme industry scenarios that could challenge the effective operation of the energy markets. They therefore provide contingency functionality to address the realization of these scenarios. Much of this functionality is yet to be tested.

Observations and suggestions for further analysis or review

Given the extent of structural change that will be associated with the implementation of CPRS/RET policies, it may be the case that the risk and market impact of destabilising shocks or events are perhaps greater that what was assumed when risk management functionality was developed and adopted within current versions of the market arrangements.

It follows that contingent functionality in the existing market rules may be insufficient to cover the extent and breadth of scenarios and major events that are plausible as a result of the CPRS/RET policies. There is benefit in a review of all of this functionality.

A consultative process could be managed to identify risk scenarios that may challenge the energy market frameworks. Each identified scenario could be assessed to determine what, if any, regulatory or institutional functionality may be needed to ensure the ongoing achievement of the energy market objectives, or in the case that this is not possible, that events are appropriately managed pending the recovery of the market in line with these objectives. Critical reviews could be conducted of market participant insolvency events, changed prudential and credit risks, new investment failure, market power and mitigation arrangements, and a review of power system stability that may be affected by large amounts of variable generation or shifts of production between coal, gas and renewable energy centres.

3.2.7 Movements in generation centres, load pockets and critical congestion zones

The implementation of CPRS/RET policies will cause significant structural shifts in the technology and fuel mix of electricity generation, affecting both the gas and electricity markets. The current dominance of coal-fired power generation will change, in favour of alternative technologies such as gas and wind. This will result in the movement of centres of generation, away from coal regions, towards areas surrounding major gas pipelines, and production sites, as well as localities with significant wind, solar or geothermal resources. This shift may also be shaped by the changing growth profile of competing gas production regions.

Examples of likely changes are shown in Table 3-1.

Observations and suggestions for further analysis or review

Shifts of large increments of generation will impact on the adequacy of the gas and power transmission systems. Large transmission augmentations may be needed between load regions and emergent new generation centres. The temporal pattern of new investment may be uneven, particularly between power generation, gas and electricity transmission and in gas storage. This leads to a number of observations:

- The energy markets frameworks may require the development of a coordinative process to identify and facilitate related and inter-dependent investments in gas and electricity. The more integrated planning of gas and electricity transmission could be a feature of the role of the National Transmission Planner.
- Should uneven investment occur, the energy market frameworks may need to anticipate the development of isolated load pockets that may be supply-constrained due to insufficient transmission capacity into load regions, causing critical congestion regions and periods. This has implications for the efficiency of pricing and investment signals, and also suggests that location-specific power and gas system stability provisions may be needed. This may include the construction of stand-by assets within potential load-pockets such as local gas and oil storage, dual fuel generators and demand response programs. It may also include new security-constrained dispatch processes and a changed ancillary service arrangements in electricity markets, uplift provisions in both gas and electricity, and more flexible and responsive change mechanisms in contract markets.

The effective management of these issues require integrated planning processes for gas and electricity transmission. Recommendations concerning transmission approvals are discussed elsewhere in this report.

Table 3-1 Examples of prospective power development trends

Region	From	To
VIC	Latrobe Valley (coal)	Southwest near the SEAGAS pipeline (gas) Southwest near the Otway Basin (wind and geothermal) Southeast near the Eastern Gas Pipeline (gas) North near the Culcairn to Melbourne pipeline (gas)
NSW	Hunter Valley and North coast (coal)	South-coast (gas from Eastern Gas Pipeline) Queensland (coal seam gas) Western NSW (solar thermal and geothermal) Southern regions (wind power) Various locations for gas fired generation.
QLD	Central Queensland (coal)	Western Queensland (geothermal) South-west Queensland (coal seam gas) Southern regions (wind power)
SA	Port Augusta (coal)	Moomba (geothermal) Eyre Peninsula (wind power) South coastal regions (wind power) Central region (gas fired generation)
NT		Development of solar thermal resources from remote areas in the south of the Territory.
WA	Muja (coal)	North and South of Perth (wind power) Kalgoorlie (solar thermal) Gas fired generation (gas from North-west Shelf)
TAS	Imported coal fired power	Local wind resources Hydro scheme upgrades Possible geothermal resources

3.2.8 Changed Operational Realities

The design and implementation of market infrastructure is generally based on the operational realities affecting market participants, requiring functional consistency with the mechanics of associated contracts, organisational structures and market assets. It is reasonable to assume that the major structural transformation that will result from the implementation of CPRS/RET policies will require some adjustment to market and industry operations, and therefore also to the market design.

Observations and suggestions for further analysis or review

Should the CPRS/RET policies lead to changes in the way assets are operated, or changes in the way contracts are managed, it is possible that participants may demand altered market functionality to facilitate these changes. Specific examples of such changes are summarised in Chapter 2, including issues such as the technical and commercial offer constraints that may be required by generators, changes to the pricing algorithm, to event timings and to changes to the optimisation problem that solve the operational and market dispatch schedules.

Potential issues relate to changed operating requirements associated with the movement of formerly base load coal units up the merit order, becoming mid-merit, peak-load and then possibly back-up or contingent units should their capacity be needed to provide system security. Another potential issue is the greater reliance on gas for power generation, in particular the day-ahead operational requirements of many capacity and commodity contracts and the implications that this may have, both day-ahead, and real-time, for the gas and power markets.

There may be benefit in an operational review of significant assets and contracts to understand how the mechanics of these may change as a result of the CPRS/RET policies. This review could identify and characterise the operational mechanics of each class of asset and contract, including parameters and considerations that are an input to associated decisions. These operational mechanics should be assessed against the functionality that is provided by the market rules. Where insufficient flexibility is identified, potential requirements should be flagged. The scope could extend to each of the wholesale, retail and contract markets for both gas and electricity.

3.2.9 Incremental Planning Paradigms

Planning processes throughout the energy market frameworks have relied on a premise of incremental change in directions consistent with traditional patterns of industry development and reduced exposure to economies of scale. This is so across gas and electricity, and it affects private investment planning and coordinated industry planning processes.

The structural changes that may be associated with the implementation of CPRS/RET policies will cause major step changes in infrastructure needs, therefore questioning the adequacy of traditional planning approaches.

Observations and suggestions for further analysis or review

Current transmission approval processes should be reviewed to ensure that they can accommodate the opening up of new energy regions before sufficient generating capacity is committed.

Rapid shifts away from coal-fired generation may move generation regions from areas of coal resources to areas surrounding gas pipelines and storage facilities, areas having significant wind and potentially geothermal resources. Transitional delays in transmission infrastructure (gas and electricity) investment may also require contingency assets near load regions, including gas and oil storage and dual-fuel generators. Current planning processes have not had to anticipate this extent of coordinated new and risk-contingent investment. Moreover, these processes have not had to manage large amounts of excess transmission capacity between coal regions and load centres, much of which may require cost recovery, and which may affect net equity considerations in debt funding decisions.

A consultative process could be managed to review the adequacy of existing planning processes, particularly in terms of the ability of these processes to coordinate and incentivise a step change in investment behaviour, providing for the sequence of gas and electricity sector investments that together may be needed to facilitate the structural reconfiguration of the energy industry. This review could also consider the likely cost, cost-recovery and regulated pricing processes that may be needed to accommodate a large step change in investment and asset redundancy, particularly prior to the full development of the associated generation assets and market transition.

3.2.10 Uneven regulatory obligations

The introduction of full retail competition as part of reform processes earlier this decade saw a raft of customer protection and transitional arrangements developed that imposed a greater obligations on incumbent retailers relative to second-tier retailers. Examples include obligation to supply and retailer of last resort arrangements. While these approaches were perhaps appropriate, they can in some circumstances distort the nature of competition within the market, and can make the competitive playing field more uneven.

During any process of significant structural change, there is a risk that incumbent market participants will be leaned on more to manage potential transition concerns. Moreover, the multiple and competing regulatory jurisdictions that manage the retail markets, the mix of private and public sector participants, and the national competition context of the energy markets suggest that competitive distortions may become significant in some regions.

Observations and suggestions for further analysis or review

The extent of structural change that will be associated with the introduction of the CPRS/RET policies could distort the nature of competition facing various sectors of the energy market:

- Some customer segments may have transitional price caps or other customer protection provisions imposed by regulation. This may impose greater costs onto other customers or onto incumbent retailers. Some customer segments may suffer a reduction in the extent and quality of contestable offers.

- Factors such as increasing spot market volatility, liquidity changes in the financial/hedging markets and a tightening of customer protection arrangements may combine to increase counter-party and credit risks, requiring a review of prudential and insolvency provisions within the gas and power markets. More strident controls, such as larger bank guarantees, could squeeze smaller participants, and prevent the market entry of others, thereby reducing market competition in the retail, wholesale and financial/contracts markets.
- Uneven provisions may cause structural changes, in particular a further consolidation of participants in the combined energy markets, in favour of larger and more integrated firms.
- The industry may benefit from a review of co-insurance schemes, risk sharing mechanisms and transitional funding arrangements that may be useful as a temporary measure to smooth the structural changes resultant from CPRS/RET policies, and to avoid an uneven burden of cost or risk falling on certain customer segments or industry participants.

3.2.11 Trade-offs between the competing needs for certainty, flexibility and innovation

In the context of this review, a successful regulatory reform outcome is the achievement of an adaptive and efficient energy market that over time can deliver organisational and product innovation, ensure ongoing reliability and security of supply, that allows failures to disappear, and that can generally promote a range of flexible responses to the transition challenges that will lead us to a lower carbon energy economy. It is one thing to get the framework "right" at a moment of time; it is something else to create a framework that is effective over time.

Regulation itself can be viewed as the design of an incomplete contract[17]. Decisions on regulation involve a trade-off between regulatory rigidities that may be designed to tightly manage the behaviour or market function, and regulatory flexibilities that allow for innovation and unexpected change, but which may come with higher expected costs of opportunism and less definite regulatory provisions.

There needs to be sufficient regulation to ensure that uncertainties associated with policy reform do not undermine regulatory objectives, while providing sufficient regulatory flexibility to promote innovation that may lead to unconventional, novel or unanticipated solutions.

Observations and suggestions for further analysis or review

One concern is that imposing a large number of changes now to the energy market frameworks to address the full breadth of potential uncertainties will bog down the intellectual resources of market participants in managing the regulatory change rather

[17] See Appendix A, Section 103 for a discussion of the energy markets framework as an incomplete regulatory contract.

than responding to the climate issue itself. It would potentially stifle innovation and flexibility of response.

The energy market transition may be facilitated by a relaxation of constraints that might otherwise impede new forms of competition, and a lowering of regulation-based barriers to entry.

Innovations to assist the transition process may also be beneficial, such as government funded pilot plants for emerging technologies, and enabling of innovative retail and financial products, and novel contractual terms.

Readily available information on the development and application of new technologies and the locations where they would have enhanced value in managing constraints would assist market participants to respond to change effectively.

Suggestions for further review include:

- A review of the existing energy market frameworks to identify impediments to future competition, such as reducing the number of licence conditions, designing more flexible planning guidelines, and removal of energy price caps.
- Upgrading the management of reliability and reserve trading.
- Enhancing the planning of new transmission easements and assets.
- Increasing the information available on the value of distributed resources in managing network constraints.
- New policies to facilitate energy innovation, such as through early stage financing of new energy technologies.

4 SPECIFIC ISSUES FOR ENERGY MARKET FRAMEWORKS

This chapter summarises a suite of specific issues related to competition, organisational structure and counter-party behaviour that could eventuate under credible scenarios and which could require adjustments in the energy market frameworks.

4.1 Issues related to competition

This section discusses ways in which the implementation of the CPRS and RET may affect the competitiveness of the energy markets. Potential issues are limited to the initial transition phase during which the industry adjusts to the implementation of CPRS/RET policies[18].

4.1.1 Potential competition issues in the wholesale electricity markets

Potential competition issues that may develop in the wholesale electricity markets are an outcome of the structural changes that will accompany CPRS/RET policies, and the effect these may have on participant behaviour. A driving factor of potential competition concern is the impact of uneven investment in transmission and generation assets, which may reduce competitiveness in some regions during periods of high load. Structural complexity between the gas and electricity markets, and between the retail, wholesale and other sectors, raise a number of inter-relationships that may drive or obscure complex strategic behaviour between and within markets.

4.1.1.1 New entry

In the context of competition analysis, the term 'barrier to entry' refers to any impediment to market entry that has the effect of reducing or limiting competition. Impediments may be either structural or strategic. Structural barriers relate to the cost and demand conditions that are an outcome of the technology, engineering, regulatory and institutional frameworks that together define the industry. Examples include economies of scale, scope and learning. Strategic barriers by comparison, relate more to the behaviour of incumbent firms, particularly intentional behaviour that creates or enhances impediments for firms to enter a market. Strategic behaviour may stem from structural influences such as regulatory change, so it is possible that structural changes in the industry may give rise to both structural and strategic barriers to entry.

Factors that could delay or prevent new entry include:

- The potential emergence of isolated pockets of generation which, via the emergence of congestion zones, may constrain electricity supply into a load region. This may cause deliverability problems in emerging new generation areas, including regions between gas transmission lines and load centres. The result is that new generation investment

[18] Also refer to Appendix A, Section A.5 for a discussion of the ways in which energy competitors may reposition themselves to seize the opportunities of a low-carbon future.

decisions may be delayed by transitional power flow constraints on the transmission system that may prevent the realisation of regional prices during peak load conditions, and therefore not provide for sufficient fixed cost recovery for generation investments.

- The possibility that greater spot market risk caused by early unit retirements may also raise prudential/credit risk for the administered and bilateral markets. This may require more onerous prudential and credit risk management arrangements such as a need for larger bank guarantees in the case of the wholesale spot market. Depending on how these arrangements are developed, there is a risk that smaller and less diversified potential market entrants on the demand side may defer or abandon further market participation.

- The timing of new generation entry is in part determined by the required rates of return associated with the costs of equity and debt. Uncertainty and spot market volatility under a CPRS could combine so that the required rate of return applied to private sector investments may increase, having the effect that associated investments are delayed until uncertainties resolve and expected revenues increase sufficiently to cover the higher discount rate. It is possible that investment monitoring by governments and market operators may underestimate the investment risks associated with market entry, thereby assuming a lower discount rate than that required by the private sector. The result is that the monitoring authorities may incorrectly perceive a pending reliability problem and intervene in the market to resolve the situation. This intervention could distort the investment markets if it has the effect of foreclosing merchant or private sector investment.

- Several factors could reduce liquidity in contract markets and make risk more difficult to price in contracts. Contract market issues may reduce revenues for generation, delaying new entry in generation. Viable hedging options for retailers may become limited and cause financial market suppliers that have no affiliated generation portfolio to exit the market. Factors that could impede the efficiency of contract markets include:

    - Transitional spot market volatility caused by the sequential and early retirements of coal units, combined with transmission congestion issues, could make spot market risk difficult to price, thereby reducing liquidity in the contract markets.

    - Emerging congestion problems between load centres and new generation regions, or on gas transmission pipelines may limit the deliverability of gas-fired generation, and therefore also their ability to physically hedge their financial contracts. This may reduce the contracts that they would be willing to offer, or require a large risk margin that may dissuade buyers from market participation.

    - Less liquidity and greater spot market risk may increase the need to physically hedge financial contracts, causing contract market suppliers that do not have an affiliated generation portfolio, such as the banking sector, to exit the market.

- Liquidity in the contract markets could be further affected by the changed maintenance strategies, and hence reduction in reliability, of the coal units, limiting the number of firm contracts that could be offered by these units. Fixed cost recovery for these units may be transferred from the contract to the spot market, further raising prices and volatility, while also causing difficulties in the contract markets for retail market participants.

Observations and suggestions for further analysis or review

The energy market frameworks are expected to manage these matters on an operational basis through the pricing mechanism and through credit risk management processes.

If adverse outcomes arise from companies seeking to preserve their market solvency through lessening competition, then the competitive principle of the energy market frameworks could break down. Competition can best be maintained by ensuring that reserve plant can secure revenue commensurate with economic value and that the declining performance of the retiring high emission generation is recognised in defining targeted reserve levels and securing additional reserve capacity from the supply and demand sides in a timely manner. Our discussions in this report concerning reliability and reserve capacity management suggest areas of review to help to maintain competition in wholesale energy which will feed through the retail supply chain.

4.1.1.2 Market power and capacity withholding

Economic and physical withholding are mechanisms of market power, providing a means for influencing market prices and settlement outcomes. Withholding in the context of the wholesale market refers to the ability of a generator to limit production on some units in order to increase market prices and to profit more from production on remaining units. Economic withholding refers to capacity withholding strategies that are effected via bidding behaviour, particularly when supply offers or demand bids are submitted at prices well beyond marginal cost (i.e. generation capacity is priced out of the competitive region of the merit order, thereby making it unavailable to the market at competitive prices). Physical withholding refers to conduct that causes units to be unavailable to the market when they are technically available. This can be caused by unrealistic technical offer constraints (such as ramp rates) that may cause the unit to be constrained-off when is technically available, or via other strategies such as maintenance down-time or dragging.

Factors that may increase the risk of economic or physical withholding:

- As large coal units approach retirement, they will move up through the merit order. Should these units retire early, prior to replacement units becoming available to the market, it is possible that reserve capacity may reduce, thereby increasing the potential that some market participants will become pivotal on days of high load. Pivotal suppliers are those that are required by the market to serve load and they therefore have price setting power.

- Insufficient technical and commercial offer constraints provided within the market rules may require a reliance on bid prices to manage operational inflexibilities, providing scope and justification for bidding above traditional costs.
- Strategic portfolio behaviour whereby multi-unit thermal generators choose to mothball one or more units earlier than required for the benefit of leveraging prices that could be received by production from remaining units.
- Changed unit maintenance strategies of coal units.
- Complexity in unit commitment decisions.

Observations and suggestions for further analysis or review

This issue does not present an immediate concern for the energy market frameworks, but it does warrant further analysis. Scenario based conduct and impact modelling is recommended at a unit and portfolio level, with analysis around critical retirement thresholds for significant coal units, and with some sensitivity to investment lags. The analysis should seek to identify potential pivotal suppliers in the various scenarios, and provide a basis for the advanced development of market power mitigation arrangement if the risks are deemed material.

At least during the period when the CPRS is being implemented, more robust market monitoring systems may be required, including functionality for:

- The physical audit of electric facilities to verify unit operations and validate forecast levels of reliability that are used in planning required capacity reserve levels.
- Routine conduct and impact testing for physical and economic withholding behaviour.
- Participant portfolio analysis to identify and monitor pivotal suppliers.
- Explicit bidding of start-up and shut-down costs, thereby removing these components from energy bids. This may make costs more transparent.
- The development of stand-by market power mitigation arrangements.

The industry may benefit from the development of a suite of stand-by market power mitigation arrangements, such as arrangements for the setting of default bids and sanctions that are linked to the market impacts of inappropriate conduct. This regulatory functionality could be introduced to address market concerns as they develop, and may in themselves constrain behaviour in advance of problems developing.

4.1.1.3 Increased potential for uneconomic supply

Uneconomic supply generally refers to the submission of production offers below competitive cost. In a transitional market in which whole classes of generation are moving towards retirement, uneconomic supply can affect the timing and sequencing of retirement, having implication for wholesale market prices over time. If earlier plant retirement due to lower revenues for high emission plant could enhance the market power of the remaining incumbents, then there may be incentive for uneconomic supply to force out-of-merit retirement, thereby lessening competition after premature retirement.

As scheduled demand increases towards the limits of installed capacity, wholesale market price outcomes can increase dramatically as peaking units with smaller capacity factors are progressively dispatched, in each instance requiring higher prices to provide for greater levels of variable and fixed cost recovery. The removal of a large increment of generation capacity from the merit order can therefore have effects on dispatch prices that are disproportionately greater for higher levels of demand than for lower levels of demand. The payoff from uneconomic supply can therefore be large if it has the effect of causing marginal coal units to be mothballed or retired early. The lower flexibility of large coal units, particularly in relation to boiler operations, make them particularly vulnerable to more flexible units as they move up the merit order.

Observations and suggestions for further analysis or review

This issue does not present an immediate concern for the energy market frameworks. However, if it were to occur such as to accelerate the retirement of coal fired plant, it may be largely invisible at the public market level until plants suddenly retire in response to low market prices. Monitoring energy market prices and comparing them with short-run marginal costs would provide an early warning sign.

It might be argued that accelerating the retirement of high emission plant under these circumstances supports the objectives of CPRS, although at the uneconomic expense of energy customers. Whilst this behaviour is covered under the Trade Practices Act, in practice it is difficult to prove in electricity markets operating under self-commitment and with multiple risks and constraints to manage.

4.1.2 Accommodating the entry of DSR, distributed and embedded generators

The structural transformation that will be required of the gas and electricity industries in response to CPRS/RET policies will necessarily feature demand side response (DSR), as well as distributed and embedded generators, which together will become increasingly important in smoothing the impact of infrastructure investment activities on the wholesale and retail markets. It will be important that the energy market frameworks can accommodate timely and substantial new entry of services and participants in these areas. DSR in particular could become a critical transition strategy to overcome investment critical investment lags if they occur.

We understand that the AEMC is conducting a review of demand side participation concurrently with the Climate Change review. Some of these issues are picked up in that review's issues paper.

Observations and suggestions for further analysis or review

The energy market frameworks will need to ensure that planning, information, trading, pricing and cost recovery arrangements can provide for innovation and investment in

DSR, distributed and embedded generators, and that these can fairly compete with alternative and indeed substitute investments in traditional generation and transmission/distribution assets.

Current regulatory network pricing and investment regimes provide certainty to network investments and may favour transmission and distribution investment over embedded low emission generation investment to address network issues. MMA's analysis has indicated conceptually the benefits of providing more clarity concerning the most favourable location and timing of distributed and embedded generation that could serve as alternatives to network investments. Better market information could encourage customers and investors to exploit these more efficient alternatives instead of large scale generation in remote locations.

Alternatives to the high cost stand-by arrangements and connection agreements for embedded demand-side resources may need to be found. Currently, demand-side distributed and embedded generators like co-generators face very high costs for grid back up. The current stand-by pricing arrangement reflects the cost to the network of supplying demand during peak periods in the event that the embedded generator is off-line. However, this will only occur during a double contingency, that is, the embedded generator is off-line during a peak demand event. The probability of this occurring is extremely small and the stand-by pricing arrangements may need to be changed to reflect this small probability. As more distributed resources are connected in one locality, the expected stand-by requirement becomes a smaller proportion of the total amount of distributed resources and the feasibility of treating the stand-by requirement on a probabilistic basis becomes more viable.

Demand-side loads have no information on the economic value of load reduction at specific locations to enable rational development and aggregation of demand side responses. The implementation of nodal pricing would reflect the true cost of energy at the various nodes in the transmission system. This would provide a price signal to the demand side that aggregators of demand resources may be able to use in presenting load shedding propositions. However, even under such arrangements much of the value of demand-side reduction cannot be captured by the provider because there are limited means to contract the capacity provided. More effective ways to contract the value of demand-side response may be beneficial. There are implications for the generation side of the market, particularly the substantial implications for risk management in the presence of network congestion. Nonetheless, consideration may be given to undertake a review of the merits of nodal pricing given the changing market structure under emissions trading.

Network planning arrangements do not provide sufficient transparency to provide demand-side response and embedded generation the information to assess where on the network non-network alternative solutions can be implemented to achieve overall lower costs. The price paid for small scale renewable and low emission distributed generation technology does not take into account the value and benefits to the electricity network. There is a question over whether the current rates for PV generation enshrined in state-based feed-in tariff schemes are equivalent to the value to society of the distributed PV generation. In principle, the feed-in tariff should be set at a rate equivalent to the value from avoiding purchasing energy in peak pricing periods and avoided network costs.

There is no information to indicate the economic value of network augmentation deferment at specific locations that would provide a basis for planning of distributed resources. The Annual Planning Statements indicate where transmission works may be needed but they do not indicate the value of deferrals. There may be questions about whether releasing such information might undermine competitive bidding for demand side response but to some extent competitive bidding is already limited by the absence of suitable information on economic value. Such information is difficult to obtain unless you are a network service provider because the necessary data are treated as confidential.

4.1.3 Other potential competition issues related to the gas industry

4.1.3.1 Issues related to gas production

To date the upstream gas sector has been largely unregulated and structurally separate from down-stream sectors. This is changing however:

- There is emerging horizontal integration. The number of players initially increased as the markets freed up, and CSG explorers increased. However, this is likely to reduce over time, as there is horizontal consolidation in the industry. There is an increasing consolidation of reserves and exploration acreage among players. Further, there is an emerging LNG exports market from Queensland, tying up significant reserves, and large contract volumes that are tying up a significant proportion of forward production.
- The Foreign Investment Review Board has supported a significant upstream investment in large vertically integrated utility. Further, gas producers are also taking on more involvement in generation.
- The WA government has reserved quantities of gas for "domestic" down-stream use

There is uncertainty about gas pricing but an expectation that it will move up, especially due to the export pricing of LNG.

The CPRS/RET policies are raising growth expectations for the sector:

- In electricity generation gas is expected to be the transitional fuel and forecast gas prices are rising strongly in some quarters.
- For cogeneration and replacement boiler fuel.
- For distributed generation.
- For transport (LNG and CNG).
- Although household and small commercial sectors to remain reasonably flat due to price increases to customers.

The CPRS/RET policies will increase the price of gas compared to the previous lower demand. This will be exacerbated by LNG exports that may cause prices to converge to international levels.

Potential issues for the energy market frameworks of the impact of CPRS on upstream gas markets include:

- Gas is expected to be the transitional fuel in power generation. The ownership of gas and gas reserves may provide market power opportunities, affecting the electricity industry. The owners of gas may be able to exert market power, both in terms of the availability of large volumes of gas, but also in relation to the largest gas generators (Arrow and AGL in TPS, Origin at Spring Gully and Mortlake, QGC at Condamine). This may raise commodity prices, as well as prices in down-stream markets.
- Even without a large use of gas for power generation, upstream prices are likely to increase significantly due to LNG and flow-through effects.
- A consolidation of producers may concentrate the sector, further raising a propensity for market power problems.
- Growth in reserves may be limited in some regions. Access to gas in Queensland is already tight beyond 2014. This may also become the case in southern Australia if electricity generation from gas increases significantly.
- Credible scenarios can be constructed in which smaller producers may have constrained access to unregulated but common infrastructure such as treatment plants, storage facilities, compression and in future LNG plants.
- There may be availability constraints in commodity and carriage, challenging the ability of gas to meet required levels of generation.
- Carbon costs in contracts are likely to result in contractual disputes. They are generally likely to be seen as additional imposts and passed on to customers, but this may not always be the case.

Observations and suggestions for further analysis or review

While these issues do not present an immediate concern for the energy market frameworks, a process of review is required to understand critical interactions between the gas and electricity industries. Once these interactions are understood, participant behaviour modelling should be conducted around a set of critical infrastructure investment/investment response scenarios to understand whether these interactions could be used to support inter-market strategic behaviour, thereby affecting the competitive performance of the integrated markets. This review should consider important assets such as pipeline and storage capacity, and also consider planning, dispatch and security of supply processes in each industry to assess whether further robustness is required to explicitly address inter-market dependencies.

The energy market frameworks will need to evolve to manage a much more dynamic environment for wholesale gas in both supply and transmission. Market monitoring activities should be reviewed to ensure processes can identify and act on complex behaviour that spans markets and sectors.

Further questions and issues that could benefit from a review include:

- Whether some regulation is required to control the potential market power of gas owners.
- Whether controls are required to ensure sufficient gas is available locally.
- Controls on horizontal integration and on the purchase of large gas volumes by existing producers.
- The impact of decisions by the Foreign Investment Review Board concerning investments in the gas industry.
- Issues related to carbon costs and allocations for fugitives, fuel, flare – especially if these are combined with free permits for Emission Intensive Trade Exposed (EITE) sectors.

4.1.3.2 Issues related to gas transmission

Initially gas transmission was installed as single pipelines serving single markets. Now it is largely interconnected with at least two transmission pipelines supplying key centres in Victoria (LTD, SWP), NSW (MSP, EGP) and South Australia (MAP, SEAGas). Queensland is still largely one pipeline to one demand centre (RBP, QGP, CGP, NQGP) but a second or third pipeline might supply into Gladstone.

Ownership of transmission pipelines has been separated and regulated according to Access Code. More recently some have been removed from this regulation (MSP, MAP) when 2 pipelines supplied one location. Further removal of coverage of pipelines is likely as the network develops.

There is increasingly tight control of imbalance of injection and withdrawal. As a result, the value of line pack will be increased with a more dynamic pattern of gas demand. This could result in the move towards regional and hourly, rather than daily, markets with the development of the Short Term Trading Market (STTM).

The CPRS/RET policies will influence further changes:

- Expected growth in electricity generation will bring forward the need for capacity expansion.
- Additional pipelines and bypass issues will arise.
- Gas usage for electricity generation is a very demanding requirement for transmission and distribution pipelines due to the volatility of gas flow and capacity constraints.

- More innovative services are likely to be sought, including park and loan. This means there are likely to be more markets needing development and more issues regarding access to capacity and line pack.
- Transmission loads are likely to increase. Load factors may change, however, not clear how. If, however, significant EITE gas loads exit the industry they could reduce transmission volumes on some pipelines

Potential issues for the energy market frameworks include:

- Reduced number of pipelines which are covered. This is probably a good result from a regulatory point of view but may mean more disputes.
- Potentially more disputes relating to short-term operational factors, e.g. balancing.
- Ensuring new STTM developments relieve concerns about barriers to small retailers.
- Paying for transmission upgrades – whether incremental or smeared - and how to meet the regulatory tests.
- Developing regional and hourly markets.
- Determining whether the day-ahead operational mechanics that are common in gas related contracts may require greater day-ahead functionality within the organised electricity markets.
- Taking account of revenue for non-Access Arrangement based services.
- System security issues as demand increases for power generation.
- Passing on carbon costs for system use gas will need to be included in regulated pricing.
- Contractual disputes may increase due to contention about passing on costs of carbon.

Observations and suggestions for further analysis or review

While these issues do not present an immediate concern for the energy market frameworks, there is the potential for emerging congestion on major pipelines having a competitive impact on both the gas and electricity markets. Episodes of congestion can impair the competitive response of participants to scarcity events, and create pivotal suppliers in regions down-stream of constraints. The energy market frameworks could benefit from a scenario based congestion study to identify the potential emergence of critical congestion corridors and load pockets that may warrant early attention to ensure the ongoing resilience of the energy market frameworks to potential challenges, and to understand whether transitional investment issues may cause emergent congestion constraints that lessen competition.

4.1.4 Issues related to gas storage

Currently, there is only limited general access storage in Australia. Underground gas storage at Iona in south west Victoria, LNG in Victoria near Dandenong and at Mondarra in WA are the main storage assets to date. Private storage exists at Moomba (Santos) and south east Queensland (Origin).

As supply contracts move towards lower swing factors and demand swing requirements increase, storage will become more important. There has been talk about additional storage to cope with LNG build-up in Queensland.

The CPRS/RET policies will influence further changes. Potential issues for the energy market frameworks include:

- There may be more call for regulation of storage.
- System security requirements may be such as to require additional or new storage to be built, possibly with regulated pricing.

Observations and suggestions for further analysis or review

In other parts of this report, we have raised potential planning and reliability management issues that capture gas storage related concerns. We have also suggested that the operational functionality within the electricity market scheduling systems may need to be reviewed in order to address potential changes in the operational realities of gas market activities, such as those related to the use of gas storage capacity which may be relevant for gas-fired generation. We have not identified any further issue for the energy market frameworks in this regard.

4.1.5 Issues related to gas distribution

Gas distribution systems are established in most states and regions. The CPRS/RET policies could however influence some changes:

- Possibility of increasing usage for micro-generation and cogeneration and natural gas for vehicles (NGV).
- Increase in gas hot water services in new homes and on change-over – but balanced to some extent by reductions due to solar-gas and increased use of reverse cycle for heating.
- Reduced usage due to energy efficiency.
- Reduced usage due to CPRS affected industry re-locating.

Potential issues for the energy market frameworks include:

- Potential demand changes and uncertainty about demand.
- New technology may make some parts of the distribution system redundant.

- New pipelines may make some parts of the distribution system redundant (e.g. Hunter Pipeline may bypass parts of the NSW distribution network in Newcastle).

Observations and suggestions for further analysis or review

Power and gas system operations at the network and transmission system level may need to attend to local reliability issues in the future, requiring new network support services to address what may emerge as transitional congestion issues associated with the effect of CPRS/RET policies. Other markets have responded to critical congestion concerns by requiring local generation to have dual fuel firing capabilities to ensure that gas and electricity networks can manage gas supply constraints.

4.1.6 Potential competition issues in the energy retail markets

4.1.6.1 Uncertainties affecting the terms, conditions, prices and costs of retail contracts[19]

Traditional retail contracts have featured some rigidity, particularly in terms of the flexibility in negotiated prices in responding to variable cost pressures. To date this has been manageable given that most retail costs are well known when contracts are struck.

Retailers require a high level of certainty in transmission, distribution and commodity costs in order to deliver the levels of price certainty that have traditionally featured in retail contracts. In the past, network service costs have been regulated and stable and could be passed through to customers. Wholesale market costs could be physically and financially hedged over reasonable terms. Inherent risks to the wholesale market have been manageable, and have evolved via incremental and steady growth in demand, upstream supply and physical infrastructure.

The competing state jurisdictions are largely responsible for retail pricing. Pricing to large customers is mostly deregulated across Australia in both gas and electricity. Pricing to small customers is still regulated in some regions. With the exception of Queensland, reasonable levels of competition have developed in the retail market. Queensland features many small gas customers that have a large cost to serve relative to realised prices.

MMA analysis suggests that current retail margins are about 5% to 8% of costs for a small customer, reducing to 0.5% to 3% for larger customers. For a customer paying $600/year for 25 GJ of gas, this translates to about $30 to $50/customer (more in Vic, less in Qld). Most sectors of the retail market have experienced adequate levels of competition, providing service innovation and competitive prices.

With the introduction of CPRS/RET policies, some costs will become more difficult to manage within the rigidity of traditional retail contacts. Very large anticipatory infrastructure investments will be required in transmission (gas and electricity), many of which may be contingent projects, causing pass-through pressures and risks for retailers.

[19] See Appendix A, Section A.4.2 for a discussion on the economics of contracting in energy markets; including evidence on contract duration and contract design.

Wholesale market settlement outcomes could become more volatile, and could cause dysfunction in the contract markets, making hedging more costly and difficult. Anticipated demand for gas could cause transitional constraints in the supply of transmission capacity, constraining supply opportunities in gas and electricity, while also contributing to larger wholesale market price volatility.

MMA analysis has suggested that CPRS/RET policies could affect gas retailers in numerous ways:

- There will be an initial increase in wholesale gas prices as producers pass through fugitive and fuel costs to retailers under contracts. The extent of this will be unclear to the retailer until the calculations are made and be proportional to the carbon price. Say 10% of heating value or \$0.12/GJ or \$3/customer consuming 25 GJ per annum at \$20/t CO_2.
- There will be a further increase as the retailer passes through the emission costs related to fuel value. Say \$1.20/GJ or \$30/customer consuming 25 GJ per annum at \$20/t CO_2.
- The CPRS impact on distribution losses may add a further component – say \$4/GJ for a 25 GJ customer at \$20/t CO_2.
- In total, the carbon impost could be \$37/customer at \$20/t CO_2.
- The difference could largely wipe out the retail margin for small customers. For some customers it would greatly exceed the retail margin – and may put the retailer at risk[20]. The uncertainty is exacerbated for those supplying both electricity and gas
- The retailers will presumably try to pass through costs or hedge if possible or, if not, seek to pass through significant risk margins.

Observations and suggestions for further analysis or review

Cumulative cost pressures on some segments of the retail market may exceed what could be acceptable to the community, raising the risk that full cost pass through may be constrained via the imposition of transitional price caps. More onerous customer protection arrangements may also combine to raise transaction costs for mass-market customers, making them increasingly undesirable. This could dissuade new entry into these segments of the retail market, and could also cause some retailers to exit unprofitable segments, having the combined impact that competition is lessened.

It is also possible that the cumulative cost pressures on retailers raise credit and insolvency risks for certain classes of retailer, constraining their ability to hedge wholesale market costs, making market registration and bilateral contracting more costly, and raising the

[20] For example, a 1 PJ customer paying \$6/GJ may mean a \$60,000 retail margin. This would be wiped out if the retailer is out by \$1/t CO2. If the retailer is out by \$10/t it would cost \$600,000.

likelihood that retailer of last resort provisions may be tested. Again, this could have the effect of lessening competition in these affected customer segments.

The energy market frameworks currently provide functionality to manage these risks, however the level and extent of risk may increase with the CPRS/RET policies, questioning whether current arrangements will be adequate in the future.

These scenarios suggest that insolvency and registration provisions in the energy market frameworks may be tested. The robustness of current arrangements should be reviewed to ensure they can manage an increase in the likelihood and extent of risks in this regard.

4.1.6.2 Competition experienced by small mass-market customers

Small mass-market customers may experience less competition and may become increasingly undesirable.

- Credible scenarios of excessive gas and electricity spot market volatility can be constructed that would imply large and volatile cost pressures for the retail sector. This sector features contractual rigidity with end-users as well as varying retail market regulations at the state level. It is conceivable that wholesale market settlement outcomes could imply retail cost pressures that are unacceptable to the community for the smallest mass market customers, raising the risk that some jurisdictions may impose transitional price caps and other safety net constraints, making these customers undesirable to retailers, and forcing cross-subsidies onto other components of the energy market.
- Customer protection arrangements may become more onerous, limiting cost pass-through of increased wholesale market/upstream costs
- Regulatory obligations may become more onerous, especially with respect to information provision, contractual terms and conditions, pricing and obligation to serve/retailer of last resort
- Margins will likely diminish; the proportion of loss-making customers could increase
- Retailers may have incentives to jettison these customers:
  - Their cost to serve could increase, especially load factor costs if supply margins tighten and peak power prices increase as a result
  - There may be an incentive for carbon cross subsidies to be transferred to other segments in the customer portfolio

Observations and suggestions for further analysis or review

A coordinated regulatory response dialogue should be maintained with all jurisdictions that have an interest in the energy market frameworks to anticipate jurisdictional tensions in advance of problems developing.

The current process could benefit from further analysis to identify what aspects of the energy market frameworks may become stressed, if any, should carbon cross subsidies be forced onto other segments of the retail market, or from operational margins earned upstream of the retail function.

4.1.6.3 Competition experienced by other mass-market and commercial customers

- Temperature-sensitive, high load-factor customers may face significant upwards price pressure
  - The contract market may tighten and feature pricing that cannot be passed through to end-use customers (see section3.2.3);
  - Higher more uncertain wholesale market risk;
  - Risk perhaps difficult to value;
  - Financial market participants without an affiliated generator/physical gas may exit the market;
  - Load factor costs may be difficult and costly to hedge.
- Some retailers may have an incentive to use excessive wholesale and contract market volatility as a justification for increasing risk margins in retail pricing, perhaps above competitive levels
- Larger mass market and commercial customers may benefit from greater service and product innovation
  - Demand management incentives as a transitional strategy to address delayed generation investment and early plant retirement may increase energy efficiency technology rebates and incentives, e.g.. gas boosted solar hot water;
  - Dual fuel larger loads attractive for appliance retrofit and RECs;
  - Higher-margin green energy offers may have higher take-up rates;
  - Larger customers may be more inclined to opt out of default tariffs;
  - Greater innovation may make retail prices more complex, making contract offer comparisons difficult.

Observations and suggestions for further analysis or review

- The review of energy market frameworks should consider whether current arrangements can encourage and accommodate continuing innovation and potentially unconventional solutions affecting the demand-side of the market. Arrangements should also accommodate the emergence of demand-side aggregators who could facilitate the bundling and management of demand-management capacity for the benefit of the wholesale markets. Wholesale market rules may need to be reformed to provide new trading arrangements for demand management capacity.

- There is a risk that onerous customer protection arrangements may stifle innovation in service development, pricing and contracting, or may impede the market entry of new demand-side aggregators.

4.1.6.4 *Competition experienced by industrial customers with controllable or flat loads*

- Large and controllable industrial loads may become hotly contested, and benefit from greater service and product innovation
  - First tier retailers will fight to retain, to offset cost burden from small undesirable mass market customers (seek to embed cross-subsidies);
  - Second tier retailers, competing first tier retailers and demand-side aggregators may fight to acquire (pressure to unwind cross subsidies);
  - Limited cost pass through constraints, so retailers not squeezed by wholesale market and upstream costs.
- Flat load-factor commercial and industrial customers may become increasingly desirable to offset wholesale market risk, providing a means to flatten the load factor of the overall customer portfolio, therefore offsetting the need for peak period physical and financial market hedges.
- Metering technologies may become increasingly important to support demand response/management initiatives.
- There is the potential for the expanded, deeper and faster role-out of types 1-5 meters.

Observations and suggestions for further analysis or review

- While no immediate problem is identified, the ongoing reform process will need to ensure that regulatory responses to the CPRS/RET policies recognise that the competitive retail market may constrain the ability of retailers to shift carbon cross-subsidies to other segments of the market. Uneven regulatory treatment of customers or retailers, say due to transitional price caps for mass market customers, may need to be funded from mechanisms outside of the market.

4.1.6.5 *Competitive pressures on retailers*

The following points assume the energy markets experience a significant increase in price volatility caused by investment lags and uncertainty that may be slow to resolve. This presents a less-likely scenario that the energy market frameworks may nonetheless need to address.

- If the industry experiences significant investment lags in association with CPRS/RET policies, the wholesale markets may respond with greater levels of price volatility around step-wise price shifts as successive coal units retire. Retailers generally may use wholesale market risk, including likely increases in price levels and volatility, to drive up margins.

- Expected consolidation of the sector may combine with the above to drive prices significantly higher for some customer segments, especially small/mid-sized uncontrollable and high load factor loads.

- Expected increases in wholesale market risk may require more onerous credit/prudential controls, squeezing out smaller/newer participants, and generally raising barriers to entry.

- Solvency concerns for some smaller, less integrated retailers may raise counterparty-risk and credit risk issues, affecting the contract markets, and constraining hedging opportunities. These retailers may struggle to compete.

- Small retailers targeting mass-market customers may struggle to pass through increased wholesale market costs and volatility; they may not have the scale and load diversity to manage costs, causing some market exit and potential insolvency.

- Large integrated first tier retailers may have to exercise retailer of last resort obligations if smaller second tier retailers become insolvent

- Retail sector consolidation, benefiting existing large national vertically integrated companies

- Retailers may have increased incentives for backwards integration into generation, to hedge wholesale market costs, and to overcome liquidity and pricing problems in the contract markets.

    - Contract market liquidity could become a problem in some scenarios, limiting options for retailers to hedge wholesale market risk.

    - Retailers build/acquire physical generation to hedge the volatility costs of their retail portfolio.

- New demand-side aggregators may enter the industry, signing up load-shedding and demand-management contracts to benefit from increased wholesale market price increases and volatility

- Large end-use sites may become targets for distributed generation.

- Increasing gains from horizontal integration:

- Dual fuel strategies increasingly important for portfolio load factor management and for ancillary sales and service opportunities;
- Demand side management may become increasing important as a transitional strategy, providing rebates and incentives for appliance sales and service;
- Product and service bundling may offset some regulatory costs, especially related to customer protection;
- Geographic customer diversity can have divergent and off-setting load peaks and troughs, providing portfolio benefits that single region retailers will lack.

- Gains from vertical integration:
  - Incentives to backwards integrate into generation to benefit from wholesale market risk, and to offset retail load-factor costs that may not be fully passed-through to customers. This may also overcome potential problems in the financial contracts market that could limit hedging options for firms;
  - Commodity and capacity headroom in gas relative to retail loads can provide an inexpensive source of delivered fuel for gas–fired generation;
  - Load-shedding contracts with large retail customers can support optimization gains between the retail and generation / trading divisions of integrated firms;
  - Integrated firms can trade-off physical generation, physical and financial contracts, load-shedding contracts and customer acquisition/jettison strategies to manage expected wholesale market risk.
- Gains from scale economies:
  - Increased customer protection obligations, including potential price caps may raise the minimum efficient scale of retail businesses, driving further industry consolidation, and causing some smaller retailers to face distress, and given volatility in the spot markets, unexpected market exit.

Observations and suggestions for further analysis or review

- While no immediate problem is identified, the ongoing reform process will need to ensure that regulatory responses to the CPRS/RET policies recognise that the competitive retail market may constrain the ability of retailers to shift carbon cross-subsidies to other segments of the market. Customer protection arrangements that have traditionally been imposed on first-tier retailers may need to be accommodated by arrangements that are more competitively neutral, such as co-insurance schemes or out-of-market subsidies.

- Retail sector monitoring provisions may need to be strengthened to track the potential for early competition concerns that may develop. Further, a review of information and transparency provisions generally may be warranted to provide for more timely and informed decision-making between competing retail market participants and customers.

4.2 Issues related to organisational structure

Appendix A summarises concepts and a methodology that can be used to understand issues relating to organisational structure in response to market change. We have used this framework as a guide to our preliminary analysis of these issues[21].

The following summarise potential influences on the organisational structure of energy market participants as an outcome of CPRS/RET policies. These influences are contingent on the response of industry to policy reform, and accordingly some are unique to scenarios that are perhaps credible, but that may have a low probability of occurrence.

- Multi-region, multi-sector and multi-fuel portfolios

  Many factors may extend optimisation gains to those participants that can trade-off portfolio adjustments between regions, sectors and fuels, thereby providing restructuring incentives towards this configuration:

  - Greater levels of congestion on gas and electricity transmission networks may create temporally inconsistent congestion wedges between regional prices, and may cause deliverability constraints for generators in emerging new generation regions around gas pipelines;
  - A greater level of intermittent generation may also contribute to greater regional asymmetry in the timing of peaks in scheduled demand (where price-taking and uncontrollable intermittent generation is subtracted from forecast demand to determine required dispatch levels of scheduled generation);
  - Price peaks between regions may also become increasingly asymmetrical;
  - Seasonal gas and electricity load peaks tend not be aligned, thus providing some risk management advantages of integration.

  These participants would not need to contract as much transportation, commodity and hedging capacity to meet portfolio needs given the possibility of optimising portfolio adjustments such as:

  - Load shedding in gas to provide more gas for generation;
  - Curtailment of gas generation to supply gas retail peak load;
  - Residual gas MDQ diverted to electricity generation;
  - Load shedding in electricity to provide more gas for retail;

[21] Appendix A explains the logic of transaction cost economics: how variations in certain basic characteristics of transactions lead to changes in organisational arrangements that govern trade in markets. For energy market players these arrangements include levels of vertical and horizontal integration, and the design of contracts.

  - o Asynchronous load peaks between regions to reduce the net required MDQ cover of the retail portfolio.

- Multi-fuel generation units and local gas/liquids storage

  The emergence of isolated load pockets caused by congestion on the gas and electricity transmission systems may provide incentives, and perhaps regulatory requirements for dual-fuel generation facilities near load centres, such as gas/distillate units to overcome gas supply constraints. This may encourage backwards integration into LNG storage, gas storage or liquids storage.

- Backwards integration from retail

  Concerns regarding the financial contract markets (see section 4.1.1.1) may limit the ability of retailers to financially hedge wholesale market risk, thereby providing gains from backwards integration into generation or gas storage, thereby providing a supply-side exposure to benefit from wholesale market price volatility, and to neutralise costs on the demand-side.

- Shifts towards physical hedging of wholesale market risks

  Concerns regarding the financial contract markets (see section 4.1.1.1) may require the supply of financial hedging products to be physically hedged via a generation, gas storage or gas supply portfolio, providing an off-setting physical position to reduce the market risks inherent in financial hedging contracts. This may cause some financial market participants (such as the banks) to exit the market.

- Generation technology shift towards gas peaking plants

  Uncertainties regarding the implementation and market impact of the CPRS/RET schemes can in some scenarios have the effect of deferring those investments that feature a larger increment of installed capacity, and a larger component of capital expenditure. The result is that the generation technology mix may move more in favour of low capital cost simple-cycle gas turbines that can be built and commissioned quickly. The speed and relative ease in which these can be brought to market may pre-empt investment in new gas base-load plants. This may or may not give rise to inefficiency costs in the long-run technology mix of installed capacity. The risk of excessive development of peaking capacity can be managed by building on site where conversion to combined cycle operation is feasible. However, planning for such conversions would add to lead time and costs.

- New demand-side aggregators may enter the industry, signing up load-shedding and demand management contracts to benefit from increased wholesale market price increases and volatility. Retailers may move heavily into demand-side programs to hedge wholesale market risk, to protect retail market share, and to benefit from higher expected margins from these customers

- Large end-use sites may become targets for distributed generation, creating incentives for new entry in this area of the market.
- Increasing gains from horizontal integration:
  - Dual fuel strategies increasingly important for portfolio load factor management and for ancillary sales and service opportunities;
  - Demand side management will likely become increasingly important as a transitional strategy, providing rebates and incentives for appliance sales and service;
  - Product and service bundling beyond energy may offset some regulatory costs, especially related to customer protection;
  - Geographic customer diversity can have divergent and off-setting load peaks and troughs, providing portfolio benefits that single region retailers will lack.
- Gains from vertical integration
  - Incentives to backwards integrate into generation to benefit from wholesale market risk, and to offset retail load-factor costs that may not be fully passed-through to customers. This may also overcome potential problems in the financial contracts market that could limit hedging options for firms;
  - Commodity and capacity headroom in gas relative to retail loads can provide an inexpensive source of delivered fuel for gas–fired generation;
  - Load-shedding contracts with large retail customers can support optimization gains between the retail and generation / trading divisions of integrated firms;
  - Integrated firms can trade-off physical generation, physical and financial contracts, load-shedding contracts and customer acquisition/jettison strategies to manage expected wholesale market risk.
- Gains from scale economies
  - Increased customer protection obligations, including potential price caps may raise the minimum efficient scale of retail businesses, driving further industry consolidation, and causing some smaller retailers to face distress, and given volatility in the spot markets, unexpected market exit;
  - For those retailers that are not sufficiently large to grow a national multi-fuel business, they may choose to exit the small end of the mass market.
- More cautious expansion into common infrastructure such as gas treatment plants (e.g. Moomba) and gathering lines, as well as gas storage, transportation, compression and LNG liquefaction/vaporisation plant to support the local market. This may be encouraged if capacity becomes scarce and contract prices substantially rise. The

potential emergence of greater price volatility in the wholesale markets, as well as the potential for emerging transmission system constraints in gas and electricity may give strategic value to these assets, causing cautious new investment by the large integrated utilities and upstream gas producers. Investment may be cautious as these investments could deliver the ability to influence the extent and nature of competition in the market, and therefore it may attract the attention of regulators.

- The ownership of gas and gas reserves may provide significant market power in the electricity industry. This may generally encourage investment in upstream activities by participants that have traditionally operated downstream. It may also encourage upstream participants to invest in generation and storage.

- The ownership of gas and gas reserves may provide significant market power in the electricity industry

    - Possibility of increasing usage for micro-generation and cogeneration and natural gas for vehicles (NGV);

    - Increase in gas HWS in new homes and on change-over – but balanced to some extent by reductions due to solar-gas and increased use of reverse cycle for heating;

    - Some reduced usage due to energy efficiency;

    - Some reduced usage due to CPRS affected industry re-locating.

Observations and suggestions for further analysis or review

- It is evident that the pressure for vertical and horizontal integration and scale would be strengthened by the changes that will occur under CPRS and RET.

- Increasing integration may reduce competition in the provision of some intermediate services and potentially reduce liquidity in contract markets that could further disadvantage smaller participants and strengthen the incentives for integration.

- There may be benefit in evaluating congestion response strategies to mitigate market disruption that may be caused by insufficient trading capacity in transportation, supply and contract markets.

- The emergence of demand management/response as critical transition strategy to overcome the impact of potential investment lags and competition concerns may warrant the development of new trading infrastructure, including perhaps enhancements to ancillary services, new markets for demand-response, and perhaps further enhancements in metering infrastructure.

4.3 Issues related to counterparty behaviour

This section summarises potential changes in counterparty behaviour that are specific to the significant decisions and activities of major classes of participants in the gas and electricity markets.

4.3.1 Generation

4.3.1.1 Transactions with the Market Operator

- The constraint that the market rules provide on the level of discretion that is available to the market operator is not expected to change, so no significant change is expected in the decisions that the market operator makes as a response to the activities of market generators.

- There is a potential that investment delays in the generation and transmission sectors, more intermittent generation, and emerging difficulties for coal units in managing self-commitment, may together combine to require greater intervention by the market operator to manage power system operations. Such intervention could require more frequent and extensive out-of-merit scheduling. This would make discretionary intervention by the market operator more frequent and unpredictable.

- Should gas supply or transportation infrastructure be constrained, or deemed a reliability risk to the electricity market, or further, should the market be faced with isolated load pockets during peak load conditions, the market operator may need to consider the introduction of changed arrangements to manage local reliability concerns. In some foreign markets this has required investment in dual fuel firing technologies with local oil/distillate storage to address gas system risks.

4.3.1.2 Contract market transactions

- Competing financial market service providers that haven't an affiliated physical portfolio may exit the market, causing a significant and potentially sudden increase in the number of customers seeking contracts
  - o Wholesale market volatility and uncertainty could in some scenarios become difficult to price, requiring a compensating physical supply portfolio to mitigate excessive risk. Market participants without a means or interest in taking a physical position, such as certain banks, may choose to exit the market. Others may seek to transfer contracts, or sub-contract some risk management services to remaining generators.

- Generators may find that emerging congestion and transmission constraints may cause deliverability constraints for their units, preventing them from receiving peak period prices. This could reduce their ability to physically hedge the contracts they offer, reducing their potential supply of firm capacity.

- Existing coal units progressing towards retirement may alter their maintenance program, causing their units to become increasingly unreliable, thereby reducing the firm contracts that they could potentially offer.

- Emerging demand-supply imbalance for firm contracts

  - Excessive wholesale market price volatility, to the extent that it becomes difficult to price and manage, may require a marked increase in volatility margins, potentially making products undesirable to buyers. This, combined with the supply-side constraints described above may cause disequilibrium and potential dysfunction in the contract markets

4.3.1.3 Investment market transactions

- Generators with a significant coal unit portfolio may face unrecoverable capital costs and outstanding debt that is not fully recoverable through the wholesale and contract markets. This may affect their net equity position, and may reduce their attractiveness to debt and equity markets, ultimately constraining their capacity for growth.

- Excessive unrecoverable debt levels of some coal exposed participants may create solvency risks that raise investment risks for funding counterparties.

4.3.1.4 Emissions/renewables market transactions

- There is prospective confusion arising from the dependence of thermal energy products and renewable energy products on the carbon price and the difficulty in finding a benchmark carbon price and applying it to both types of products in a consistent manner so that retailers do not pay twice for emission abatement (refer to section 2.15.1)

4.3.1.5 Transactions with transmission providers

- Shifts in generation clusters from coal areas to regions surrounding gas and wind resources may cause transitional infrastructure constraints that require major new transmission system investment and augmentation to address. It is possible that new generators seeking to connect in these emerging generation areas may be faced with requests for deep connection costs that are sufficiently high so as to delay or dissuade decisions to invest. They could also be faced with insufficient capacity on gas transmission systems to support generation.

- Contractual and service level tensions between generators and transmission system service providers may emerge should structural market changes cause deliverability constraints affecting generation/gas supply.

- Planning tensions may similarly emerge in relation to trade-offs between generation, demand response and transmission system investment.

4.3.1.6 Transactions with Distribution providers

- Demand for embedded/distributed generation may increase, requiring potential generators and distributers to increase their negotiations in this regard, and potentially requiring additional contractual functionality to manage local reliability and network augmentation/expansion issues.

- The potential for congestion on the transmission system and the creation of isolated load pockets may require networks to expand local reliability operations, presenting constraints and opportunities for generators generally, and potentially requiring significant infrastructure expansion.

4.3.2 Retailers

4.3.2.1 Transactions with generators

- Greater levels of wholesale market price and settlements risk may cause retailers to increase their demand for physical and financial hedging products.

- Physical hedging risks for generators, caused by the changed maintenance standards of coal units, or due to generation deliverability constraints caused by transmission system congestion, may change the firmness and term structure that generators are willing to offer retailers. Retailers may be forced into short contract terms because generators are unwilling to hedge across major market transitions due to excessive price risk. This is already apparent in the NEM with respect to contracting in 2010 and thereafter. Short contract terms are a problem when end-use customers prefer longer retail contract terms commensurate with their own business investments. Short-term contracting could have adverse effects in some sectors of the economy, particularly industrial customers.

- Retailers may find that generators are fully contracted, or may charge excessive risk margins in hedging offers. Retailers may therefore find that they need to backwards integrate into generation to physically hedge their portfolio risks, changing their status to that of a competitor in relation to other generating participants.

4.3.2.2 Transactions with gas shippers/producers

- The possibility of investment lags may cause significant congestion issues on major pipelines, thereby limiting the quantum of firm and non-firm capacity that may be needed in the retail and generation markets. Gas shippers and producers may be constrained in the ability to provide new supply, and indeed, if some residual capacity does exist, it may be subject to existing contracts, preventing use by other participants.

4.3.2.3 *Transactions with the market operator*

- It is possible that retailing risks may increase as a result of the CPRS/RET policies, particularly if the state jurisdictions constrain full cost pass-through of upstream cost exposures (wholesale market, transmission and distribution system costs, other supply and transportation costs).

- It is also possible that in some scenarios, wholesale market risks could become significant, affecting the prudential and credit quality of some retailers under existing market rules.

- The market operator may require larger bank guarantees, or more onerous credit and prudential controls for some classes of retailer, raising market registration costs, and causing cost asymmetries with larger more diverse retailers, thereby affecting the competitive dynamic.

- Other markets have shown that tightened prudential and credit management controls have had consequences in raising the minimum efficient size for market participation, affecting smaller participants in demand response and financial trading markets.

4.3.2.4 *Transactions with local regulators*

- State level jurisdictions may become faced with excessive community concern about the affordability of potential retail market price increases. These jurisdictions may introduce transitional price path controls, or other more onerous customer protection arrangements that could affect service innovation or the cost the serve, ultimately reducing retail margins for the smaller end of the retail market.

4.3.2.5 *Transactions with distribution providers*

- The distribution system operator and retailers may coordinate the roll-out of more advanced metering technologies to those larger customers that could provide economic demand-management and demand response services.

- Demand for embedded/distributed generation may increase, requiring retailers and distributers to coordinate this outcome, and potentially requiring additional contractual functionality to manage local reliability and network augmentation/expansion issues. This may cause changes in Use of System agreements and other arrangements.

- The potential for congestion on the transmission system and the creation of isolated load pockets may require networks to expand local reliability requirements, raising cost pressures for customers generally, and potentially requiring significant infrastructure expansion.

4.3.3 Customers

4.3.3.1 Transactions with the market operator

- The constraint that the market rules provide on the level of discretion that is available to the market operator is not expected to change, so no significant change is expected in the decisions that the market operator makes as a response to the activities of market customers.

- Market customers may find that the market operator requires more onerous credit and prudential requirements to qualify customers for market participation. This could occur if wholesale market volatility significantly increases.

4.3.3.2 Transactions with distribution service providers

- Distribution operators and retailers may coordinate the roll-out of more advanced metering technologies to those larger customers that could provide economic demand-management and demand response services.

- Demand for embedded/distributed generation may increase, requiring customers and distributers to increase their negotiations in this regard, and potentially requiring additional contractual functionality to manage local reliability and network augmentation/expansion issues.

- The potential for congestion on the transmission system and the creation of isolated load pockets may require networks to expand local reliability requirements, raising cost pressures for customers generally, and potentially requiring significant infrastructure expansion.

4.3.3.3 Transactions with retailers

- Small mass-market customers
  - Push by retailers for large price increases
    - The temperature sensitivity of these loads makes them expensive to supply given the high costs of supplying and transporting the commodity at times of peak load. Increases in wholesale market prices and increased price and settlements volatility could combine to encourage retailers to seek significant price increases to cover potential wholesale market costs. These potential costs could be made more substantial by the inclusion of risk margins to compensate for rigid pricing clauses that may prevent the full and timely cost pass-through of wholesale market price volatility.
  - Potential disengagement by retailers

        - Small mass-market customers have a high cost to serve, and provide very low margins that may not sufficiently amortise acquisition costs for retailers to pursue them.
        - The ability of these customers to afford rapid price increases may be limited, and the community or pricing regulators may not accept full and timely cost pass-through, raising the risk that transitional price caps may be imposed. These customers are also candidates for more onerous customer protection arrangements than may further reduce margins or constrain innovation in service offers.
        - Ultimately, depending on the response of local jurisdictions to cost-pass through efforts by retailers, these customers may become undesirable to many retailers.
    - Other mass-market and commercial customers
        - Expanded product and service bundling, including the bundling of services beyond energy, thereby expanding margins and providing greater cost recovery for greater wholesale market and distribution system costs.
        - Expanded offers for the supply and installation of energy efficient appliances
        - Some retailers may have an incentive to use excessive wholesale and contract market volatility as a justification for increasing risk margins in retail pricing, perhaps above competitive levels
        - Larger mass market and commercial customers may benefit from greater service and product innovation
            - Demand management incentives as a transitional strategy to address delayed generation investment and early plant retirement may increase energy efficiency technology rebates and incentives, e.g. gas boosted solar hot water.
            - Dual fuel larger loads attractive for appliance retrofit and RECs
            - Higher-margin green energy offers may have higher take-up rates
            - Larger customers may be more inclined to opt out of default tariffs
            - Greater innovation may make retail prices more complex, making contract offer comparisons difficult.
    - Flat load factor customers
        - Actively pursued by retailers to offset the wholesale market risks of temperature-sensitive load segments.
        - The savings that these customers could provide to a retail portfolio are very significant from a cost of hedging perspective, suggesting that these customers maybe able to negotiate very competitive market retail offers.

- o High load factor customers
  - ▪ Retailers may attempt to increase retail margins, justifying such with the costs of wholesale market risk management.
  - ▪ Retailers may seek cost pass through provisions, so they are not squeezed by unexpected shifts in wholesale market and upstream costs.
  - ▪ Customer may be provided with new and innovative service extensions, including the bundling of additional services and products beyond the energy domain. These customers may also receive energy efficiency and appliance purchase incentives related to demand management/response strategies. Retailers may seek this business, providing further revenue opportunities via service and installation contracts. This expansion in retail activity may be a response to offset higher transaction costs in the energy market.
- o Customers with large and controllable loads
  - ▪ Actively pursued by retailers
    - ▪ Large and controllable industrial loads may become hotly contested, and benefit from greater service and product innovation
    - ▪ First tier retailers will fight to retain these customers, to offset the cost burden of small undesirable mass market customers (thereby seeking to embed cross-subsidies)
    - ▪ Second tier retailers, competing first tier retailers and demand-side aggregators may fight to acquire these customers, creating competitive pressure to pressure to unwind cross subsidies.
  - ▪ Some customers may not seek the services of smaller retailers who may face credit or solvency concerns given constraints in the hedging markets, and given increased exposures to more volatile wholesale market price and settlement outcomes.

Observations and suggestions for further analysis or review

- A summary review of counterparty behaviour suggests that further analysis should be conducted to understand whether the energy market frameworks require enhancement in the following areas:
  - o An expansion of the centrally coordinated markets to provide additional trading and settlement services for financial products, thereby reducing credit/prudential/counterparty risks and transaction costs for participants.
  - o The creation of new demand response markets and augmented ancillary service markets to accommodate the potential that demand management/response becomes a major transition strategy.

- o The creation of a carbon price benchmark that can be used by market participants to adjust prices for RECs and energy derivatives so as to correctly reflect the impact of carbon price through the supply chain and among the diverse products.

4.4 Other transmission issues

4.4.1 Interconnecting transmission constraints

- The replacement of brown coal fired generation from sources outside Victoria may require a major augmentation of the transmission system throughout the southern NEM regions.

- In particular, increased access to the Eyre Peninsula, the Moomba geothermal fields will require South Australian and Victorian export capacity to be increased on a strategic basis rather than a project basis.

Observations and suggestions for further analysis or review

- The National Transmission Planning process may need to be backed up with regulatory channels to address the long-term benefits and risks of upgrading interconnectors and to extend the transmission system to new energy supply regions.

- The current review process may benefit from a review of the regulatory framework to ensure that the long-term economic benefits and risks of major transmission extensions can be recognised in the planning for and commitment to a transmission system back-bone that connects the existing and future NEM regions.

- The viability of and indicative timing for connecting Mt Isa and Darwin to the NEM could be examined to provide the basis for regional development and the planning for the acquisition of renewable energy in remote regions.

- The viability of and indicative timing for connecting the Eyre Peninsula to the 500kV system to allow connection of the wind resource and export to other NEM regions could be examined to provide the basis for renewable energy development in South Australia.

4.4.2 Network economies of scale

- The presence of economies of scale in networks combined with monopoly provision of network services means that investment in network capacity to allow low emission sources of generation to access the wholesale markets may be suboptimal. This is likely to disadvantage remote and distributed low emission technologies facing information asymmetries.
- Without major changes in the transmission infrastructure, low emission technologies may find it difficult to achieve connection, even though they may be competitive once the transmission infrastructure has been established.

- Shallow connection costs may not reflect true costs of connecting large scale renewable/nuclear generators that may be located in locations remote from the existing transmission system if the configuration of the transmission system needs to be fundamentally altered due to the relocation of the sources of generation. Better incentives for connection of remote generation and the reuse of stranded transmission assets would be achieved by moving more of the transmission system costs back to generators.
- The current regulatory regime requires those seeking connection to cover the cost up to the point of connection. For a single remotely located generator the additional cost of connection is likely to be insurmountable. If the costs can be shared between multiple generators, the likelihood of a successful network extension increases. But the extension may not eventuate due to the strong incentive to free ride on the efforts of early movers.

4.4.3 Non-incremental changes to the transmission system and potential stranding of assets

- Constraints may develop in different parts of the network as generation relocates from areas with large coal resources to areas with large wind, geothermal and solar resources.
- Nuclear plants may be able to locate in areas with strong transmission capacities vacated by the coal fired plants especially given the need for cooling water also released by the coal plants.
- At present, no significant stranding of assets have taken place where asset values have been significantly reduced due to changes in the configuration of demand and/or supply. CPRS has the potential to lead to the stranding of significant assets and thereby affecting the revenue and value of TNSPs due to the reduction in coal fired generation. Compensation issues could arise for TNSPs that are significantly affected and it is likely that the regulatory system will need to adjust to take this potential into account.
- The transition from the current generation sources could require a change in how new transmission assets are funded as the incremental approach to network expansion/augmentation is no longer valid as a general principle. It could require significant investments in transmission assets compared to the current transmission asset base which a single low emission generation project may have difficulty funding.
- Shallow connection costs may not reflect true costs of connecting large scale renewable/nuclear generators that may be located in locations remote from the existing transmission system if the configuration of the transmission system needs to be fundamentally altered due to the relocation of the sources of generation.
- The current regulatory regime requires those seeking connection to fund the cost up to the point of connection. For a single remotely located generator the additional cost of connection is likely to be insurmountable. If the costs can be shared between multiple

generators, the likelihood of a successful network extension increases. But the extension may not eventuate due to the strong incentive to free ride on the efforts of early movers.

5 SUGGESTIONS FOR FURTHER REVIEW AND ANALYSIS

This preliminary survey of matters arising from CPRS and RET has identified some key areas where outcomes are quite unpredictable and where the current energy market frameworks may not be suited to efficiently managing the apparent risks.

5.1 Further reviews, consultations and analyses

There are some potential issues related to coordinated transmission developments and the potential for delays in new capacity replacement plants under CPRS. We have identified a number of areas that would benefit from further review or analysis and these are summarised here.

5.2 High priority matters

The high priority matters that could benefit from further review include:

5.2.1 Electricity transmission funding for new areas

- The approval for and funding of transmission to the new energy regions in South Australia, Central Australia for geothermal power. It is considered that Western Power seems able to provide sufficient capacity for connection of its wind farm potential north of Perth with the 330kV transmission line to Geraldton with the major issues relating to system operation rather than funding network development.

5.2.2 Reformulation of the reliability standard and reserve capacity target

- There are two separate issues related to reliability and the role of intervention. Firstly, the potential value of intervention during the transition phase requires a longer-term measure of required capacity in the power plant development pipeline so that the market performance can be effectively monitored. Secondly, the optimal value of the unserved energy may further deviate in some regions from its currently accepted level of 0.002% in the NEM and the WEM.
- A reformulation of the reserve capacity calculation to include the effect of the evolution of growth and plant performance uncertainties over at least a five year horizon could be beneficial. This revised reserve capacity measurement would provide the basis for longer term risk assessment and possible intervention of the Reliability and Emergency Reserve Trader (RERT) during the CPRS/RET transition phase. This reform would support the enhancement of the RERT role to support longer term planning processes as described below.
- A reformulation of the unserved energy reliability standard may be useful to more accurately reflect the cost of reserve plant including demand side response, the uncertainties in thermal plant performance and the impact of expected patterns of variable generation and the uncertainty in demand growth following the CPRS and

RET price shock. There is time to consider and refine this measure because the market has already recognised that the current standard is uneconomic and has delivered additional capacity where it matters, particularly Queensland.

5.2.3 Enhancement of Reliability and Emergency Reserve Trader role

- The enhancement of the Reliability and Emergency Reserve Trader (RERT) role in the NEM to cope with potentially longer term capacity shortages up to five years in advance during the CPRS/RET transition phase. This does not require the RERT to establish a capacity market as such for the NEM but rather establish trigger points for which longer term contracting might be necessary to provide the necessary investment incentives in the event of market failure. The reformulation of the reliability standard to address longer-term uncertainties would provide the basis for a longer-term view of the risks of capacity shortage. This would provide important information to evaluate progress in the development pipeline as affected by new infrastructure requirements (gas and electricity transmission) and progress with environmental planning and approval processes.

5.3 Important matters

There are also several important matters where economic efficiency could be enhanced but it is unlikely that inaction in the next year or so would create significant cost to the energy markets. Such matters are:

5.3.1 Resilience to retailer distress

- The systems that support retail contestability will need to be resilient against the risk of retailer distress on a wider scale than has occurred during the recent drought. The Retailer of Last Resort arrangements may need to be scaled to manage a large number of customer transfers in a short period of time.

5.3.2 Trading systems for a dynamic environment

- The volatility of energy flows on a day to day basis will increase and this will increasingly affect gas flows and gas fired generation. AEMC should continue to reform gas trading arrangements to prepare for these more dynamic market conditions.

5.4 On-going monitoring

There are a number of on-going operational matters which MMA considers can be managed under the current frameworks providing there is sufficient monitoring of market performance. These include:

- Setting standards for variable generation that will work at much higher levels of penetration into the system. NEMMCO and IMO have been aware of this problem and have been taking action.

- Ensuring that credit risk management systems can cope with the larger cash flows associated with carbon price transactions and potential increases wholesale market price and settlements volatility.

5.5 Further analysis and consideration

This preliminary review of potential issues for the energy market frameworks is largely qualitative, and numerous issues are identified that should be tested with quantitative analysis. The review was completed in a minimal time-frame, so the issues presented may not fully address some of the complexities and inter-relationships that characterise the multiple markets that are managed by the energy market frameworks. The issues pervade the whole supply chain from fuel to end-use customers and all market participants and jurisdictions can have an influence on the achievement of regulatory objectives.

Many of the issues that have been identified, and for which the energy market frameworks may need to attend, relate to scenarios featuring investment lags that could challenge the achievement of regulatory objectives. Critical investment lags that present concern relate to investment in generation, gas pipeline capacity and electric transmission capacity. Should delays occur, critical and localised congestion problems may occur, creating isolated load pockets and deliverability constraints for generation and gas supply. This in turn presents a suite of issues related to market power, the adequacy of arrangements to support a major push in demand management/response strategies, and the need for enhanced reliability provisions.

To test these concerns, thereby determining the effort that may be required to enhance the energy market frameworks, the following further analysis is required:

- Scenario modelling to test the robustness of market arrangements to variations in the trajectory of investment signals and to varying levels of investment risk (as reflected in investment hurdle rates). This analysis should consider the pattern and location of new investments, and consider the impact of lags on:
  - Sub-regional power flows, thereby determining whether critical congestion corridors and isolated load pockets develop, thereby warranting enhanced local reliability, market monitoring and market scheduling functionality
  - Participant portfolio modelling to determine whether particular portfolios or assets create pivotal suppliers, having an ability to influence price and settlement outcomes. This may require scenario based conduct and impact testing around varying load and investment assumptions, to identify regions where market power issues may present a problem to the market and trading arrangements.
  - The adequacy of security of supply, credit/prudential arrangements, retailer of last resort arrangements and RERT functionality.
- The design and implementation of market infrastructure is generally based on the operational realities affecting market participants, requiring functional consistency with the mechanics of associated contracts, organisational structures and market assets. It is

reasonable to assume that the major structural transformation that will result from the implementation of CPRS/RET policies, will require some adjustment market and industry operations, and therefore also to the market design.

Should the CPRS/RET policies lead to changes in the way assets are operated, or changes in the way contracts are managed, it is likely that participants may demand altered market functionality to facilitate these changes. Specific examples of such changes are summarised in Chapter 2, including issues such as the technical and commercial offer constraints that may be required by generators, changes to the pricing algorithm, to event timings and to changes to the optimisation problem that solve the operational and market dispatch schedules.

Immediate concerns relate to changed operating requirements associated with the movement of formerly base load coal units up the merit order, becoming mid-merit, peak-load and then possibly back-up or contingent units should their capacity be needed to provide system security. Also of concern is a greater reliance on gas for power generation, in particular the day-ahead operational requirements of many capacity and commodity contracts and the implications that this may have, both day-ahead, and real-time, for the gas and power markets.

A review of significant assets and contracts could be undertaken in the context of the CPRS/RET policies. This review would anticipate the effects of the CPRS/RET policies; it would identify and characterise the operational mechanics of each class of asset and contract, including parameters and considerations that are an input to associated decisions. These operational mechanics would be assessed against the functionality that is provided by the market rules. Where insufficient flexibility is identified, potential requirements would be flagged. The scope would extend to each of the wholesale, retail and contract markets for both gas and electricity.

- A summary review of counterparty behaviour suggests that further analysis may be of benefit to understand whether the energy market frameworks could be enhanced in the following areas:
  - An expansion of the centrally coordinated markets to provide additional trading and settlement services for financial products, thereby reducing credit/prudential/counterparty risks and transaction costs for participants.
  - The creation of new demand response markets and augmented ancillary service markets to accommodate the potential that demand management/response becomes a major transition strategy.
  - The creation of a carbon price benchmark that can be used by market participants to adjust prices for RECs and energy derivatives so as to correctly reflect the impact of carbon price through the supply chain and among the diverse products.

APPENDIX A ECONOMICS OF ORGANISATIONAL STRUCTURE AND STRATEGY OF ENERGY MARKET PARTICIPANTS

A.1 Introduction

This chapter develops some concepts for thinking about organisational structure and strategy of energy market participants.

Using these concepts, the potential impacts of the CPRS/RET policies on the electricity and gas markets are summarised as follows:

1. The impact on organisational structure and strategy:

    a. To the extent that the CPRS/RET raises transaction costs by creating greater uncertainty and complexity for market participants, at least in the short term, this will drive more "integrated" forms of organisation in the sector. More integrated forms include unified ownership of assets (both vertical and horizontal), a greater use of strategic alliances and equity joint ventures instead of arms-length contracting, a reduction in the number of short-term contracting arrangements and spot market transactions.

    b. Market players will pursue strategies to reposition along the following lines: optimisation of current assets base, shifts to carbon-efficient operations, rebalancing of the asset portfolio toward less carbon-intensive plants and technologies, and the introduction of new low-carbon businesses,

    c. At a time of regulatory change and uncertainty some market players will strategically play the "re-negotiation card" to the maximum, since for these players, huge value is at stake. The precise design of the CPRS/RET can have a great bearing on profits of individual players, depending on the extent of the free emission permits, the allocation of permits to new production, and the ability to pass on price increases to end users.

2. Analyse the impact on competition:

    a. Tighter integration, horizontal or vertical, does not of itself represent a lessening of competition. One beneficial effect of competition is to push market participants towards modes of organisation that minimise transaction costs. In line with 1(a) above, integration may simply represent an economically efficient response by marker participants to a changed market environment.

    b. New entrants – with a different energy / sustainability value proposition – can be expected to challenge the incumbent carbon-intensive players. Any impediments to the emergence of new forms of competition need to be addressed within the current energy market framework.

c. Competition will be facilitated by ensuring that one of the goals of CPRS/RET policy implementation is to minimise transaction costs. Based on MMA's assessment of the key factors driving energy markets over the short to medium term, energy market performance may benefit from the CPRS/RET providing more certainty in the price of carbon, while the energy market framework relaxes other constraints so as to facilitate the structural adjustment process toward a lower carbon-intensive energy economy.

3. Analyse the impact on counter-party behaviour related to generator and retailer decisions:

    a. Disturbances to long-standing contractual arrangements between parties may arise as a result of the introduction of the CPRS/RET. If key aspects of the CPRS/RET were not anticipated at the time of contract formation, there could potentially be a rise in the level of disputations.

    b. Any strategic behaviour of counter-parties regarding nondisclosure, disguise, or distortions of information will likely lead to an attenuation of market-based transactions and a rise in greater levels of internal supply arrangements.

    c. As a general guide, rigid contract designs will be tested in times of change, so one potential outcome is the increased use of renegotiation provisions, in order to provide more flexibility.

Section A.2 looks at organisation and strategy through the lens of transaction cost economics (TCE). Section A.3 applies the logic of TCE to analyse the energy markets framework as an incomplete regulatory contract. Section A.4 analyses organisational models in energy markets, and Section A.5 discusses frameworks for thinking about the strategy of market participants in response to the introduction of CSPR/RET.

A.2 Organisation and strategy through the lens of transaction cost economics

A.2.1 Transaction Cost Economics: the new economics of organisation

Transaction Cost Economics – also described as 'the new economics of organisation' - provides a powerful lens to examine how organisational structure and strategy of energy market participants may change as a result of the CPRS/RET. In essence transaction costs are the costs of running the energy economy.

TCE is the ground where economic thinking, strategy, and organisation meet. It seeks to understand how variations in certain basic characteristics of transactions lead to changes in organisational arrangements that govern trade in markets. For energy market players these arrangements include levels of vertical and horizontal integration, and the design of contracts between buyers and sellers.

'Transaction costs' provides the unifying concept. Why? Because arranging transactions among parties is decisive for taking advantage of specialisation and requires complex devices at the micro level (modes of organising these transfers) as well as at the macro level (institutions facilitating and enforcing these transfers). And why transaction costs? Because all these devices are costly: comparing these costs is crucial for understanding how (and what) institutions and organisations enable the benefits of specialisation.

Competitive advantages of companies cannot be fully understood solely in terms of factor endowments, or only in terms of economies of scale or scope. They also depend significantly on how transactions are organised and supported. The logic of TCE is that competition pushes market participants towards adopting modes of organisation that minimise transaction costs.

Transaction cost analyses examine the incentives of both parties to maximize value in an uncertain environment, where inputs and outputs are complex and hard to specify in the contract, options and flexibility are limited (for example by the non-storability of electricity), and delays in investment in one part of the energy value chain can raise costs and reduce output or reliability in other parts of the chain.

Papers by Joskow (1988a), Lyons (1996), Masten and Saussier (2000), Shelanski and Klein (1995), and Macher and Richman (2008), reveal that the transaction cost approach has generated robust and empirically supported explanations for the organisational structure and contracting practices across many industries including coal mining, electricity, natural gas transmission, and oil and gas production.

A.2.2 Transactions in energy markets

The following major transactions are relevant in the energy markets:

1. Transactions in daily operations of the energy markets;
2. Transactions in maintenance of plant and infrastructure including transactions aimed at maintaining a defined level of service quality;
3. Transactions in planning and construction of new energy and infrastructure projects, and the retirement of obsolete plant.

Transaction costs in energy markets may be revealed in the following ways:

1. The bid/ ask spread in the energy commodity markets.
2. The costs associated with running plants at less than full capacity, due to the non-storability of electricity, combined with very little demand elasticity and the need for real-time supply/demand balancing to keep the grid stable.
3. The risk premium that must be earned to justify investment in each of the risky sub sectors of the energy value chain.

4. Production inefficiencies associated with the use of generic rather than specialized assets (to overcome the 'hold-up' problem [22]).
5. The absence of certain markets, such as long term capacity markets.

To understand why these costs emerge, the following section explains how transaction attributes drive transaction costs.

A.2.3 Characteristics of transactions affect transaction costs

Following Milgrom and Roberts (1992), there are numerous kinds of transaction attributes which drive transaction costs. Those relevant to energy markets include the following:

1. Uncertainty surrounding the future competitive market, regulatory and technological environment within which the players will be operating;
2. The relationship specificity of the investments required to support the transaction between the parties;
3. The difficulty of measuring performance and ensuring compliance.

As the intensity of these attributes increases so too the level of transaction costs. Each of these attributes is discussed below.

A.2.4 Uncertainty as a driver of transaction costs

Uncertainty refers to the impossibility of knowing precisely how a future trend or event will unfold; such as technological innovation, changes in consumer preferences, the strategies of competitors, or environmental / climate changes. It is often the case that the terms, complexity and uncertainty, are used interchangeably.

Uncertainty and complexity arise out of three main problems. First, the past is only an imperfect guide to the future. Secondly, uncertainty can arise when the outcome of a course of action depends on the simultaneous and unforecastable decisions of market participants. Such uncertainties may arise due to strategic behaviour of counter-parties regarding nondisclosure, disguise, or distortions of information.

A.2.5 Asset specificity as a driver of transaction costs

Some goods and services can be produced more efficiently if one of the parties invests in "transaction-specific" assets. Such assets cannot easily be put to other uses if the buyer-seller relationship breaks down.

Relationship-specific investments and opportunism [23] leads to the hold-up problem, which in turn leads to underinvestment by the parties to the deal. There are five types of relationship-specific investments:

[22] "Hold-up" can arise in situations where there are appropriable rents "up for grabs" in a commercial relationship. The reason is that at least one of the parties to the deal has made a relationship-specific investment in an environment where it in not possible to write a complete contract that creates a safeguard against appropriation (Williamson 1975).

[23] Opportunism arises in situations where some actor takes advantage of a position which has arisen as a result of a trade of some sort. Examples include one or both parties reneging on commitments, under-investing, and mis-reporting the facts after the contract has been signed.

Site specificity: The buyer and seller are in a "cheek-by-jowl" relationship with one another; for example, the buyer or seller locates its facilities next to the other to economize on inventories or transportation costs. Once sited, the assets in place are highly immobile. For example, electricity production may involve the use of specialised assets such as dedicated coal mines that cannot economically be re-deployed to other markets.

Physical asset specificity: When one or both parties to the transaction make investments in equipment or tooling that involves design characteristics specific to the transaction, and which have lower values in alternative uses.

Human asset specificity: one or both of the parties develop skills or knowledge specific to the buyer-seller relationship.

Dedicated assets: General investments by a supplier that would not otherwise be made but for the prospect of selling a significant amount of product to a particular customer. If the contract were terminated prematurely it would leave the supplier with significant excess capacity.

Temporal specificity: This is the extent to which timing is critical to efficient performance, such as the difficulties of finding new suppliers of resources at short notice (Masten et al, 1991). For example, the non-storability of electricity drives temporal specificity.

A.2.6 Measurement as a driver of transaction costs

Costly information, and its operational counterpart, costly measurement, is a basic driver of transaction costs. This can result from information asymmetry among trading partners regarding product value and producer effort. Alternatively, some important attributes of a traded good may not be directly observable to the buyer, seller, or both. Consequently, parties may benefit by engaging in costly searching and sorting to obtain information about the attribute of the product or service.

A.2.7 Companies have various options for organising transactions

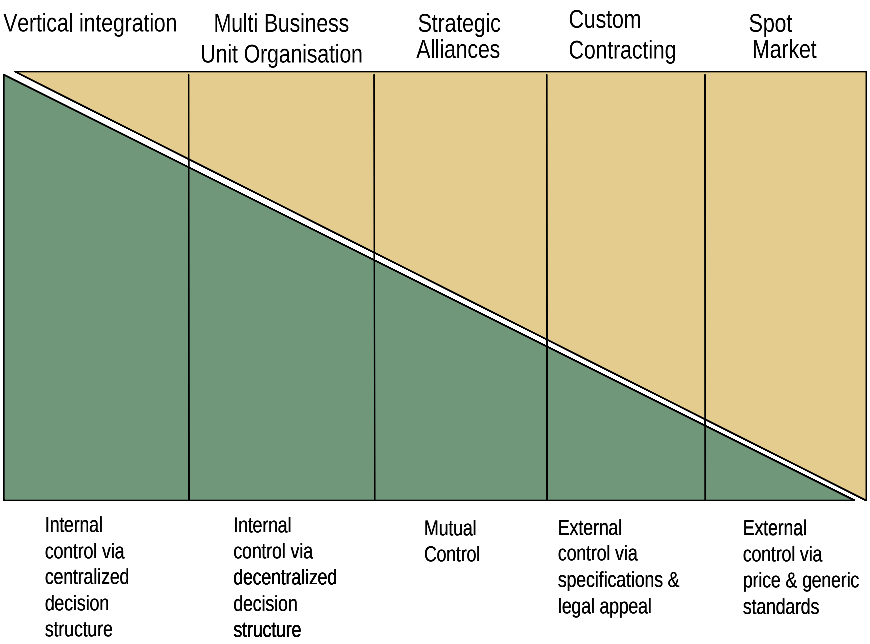
Transactions can be organized under a spectrum of governance structures ranging from pure, anonymous spot markets—where the good or service is generic and identities of buyers and sellers are immaterial to the transaction—to fully integrated firms, where both the trading parties are under unified ownership and control, and the transaction can be controlled by managerial fiat. Between the two poles of spot markets and integration are contracts of increasing duration and complexity.

The central proposition is that asset specificity, particularly in uncertain environments, creates contractual hazards: hence, the greater the specificity, the more elaborate the governance mechanism required to constrain the opportunism that may result.

A "complete" contract, specifying contingencies and what to do when they arise, will work in simple market situations. [24] But as specificity, uncertainty and measurement difficulties mount, such contracts become (cognitively) impossible to write and (in practical terms) impossible to enforce, especially in the presence of uncertainty. This sparks a move to less complete contracts, which leave more to be worked out later (Crocker and Reynolds 1993).

Figure A- 1 illustrates the various discrete organisational forms available to market participants.

Figure A- 1 The various discrete organisational forms



Vertical integration involves unified ownership, according to which multiple stages along the value chain report to a peak governance structure which manages the chain so as to promote coordinated decision making and adaptation. In a similar way horizontal integration over wide geographic areas, different customer market segments, or production / distribution of multiple energy types, represents another organising mode to hedge against uncertainty.

For complex transactions between counter parties, strategic alliances (such as equity joint ventures), or arms-length, long-term contracts may be required. These may include detailed and complex adjustment clauses to respond to contingencies over the life of the contract.

[24] One contract is said to be more complete than another if it gives a more precise definition of the requirement and of the means to carry it out. That is, the more complete a contract, the greater is the specification of obligations, rewards, and procedures contained in the contract.

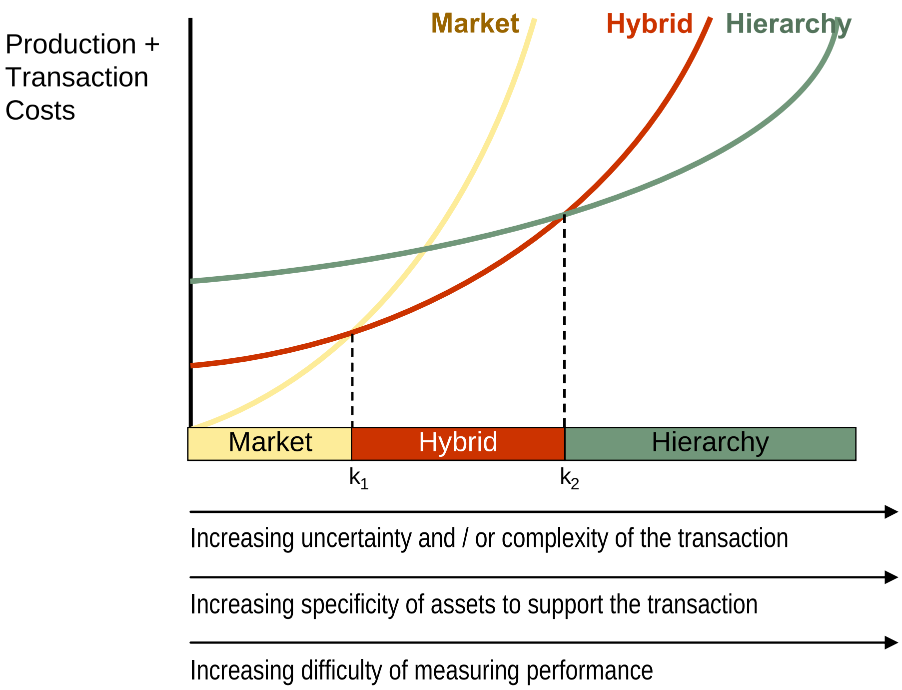
Customised contracts will supersede spot markets where a non-standardized product (for example, a flexible supply arrangement) is particularly valuable, where durable and specific investments are necessary to realize that value, and where the allocation of risk the parties prefer cannot be obtained in the market (for example, by using commercially available insurance).

Simple, short-term contracts basically require an exchange of information and terms of payment; as described by McNeil (1974, p. 738), "sharp in by clear agreement; sharp out by clear performance."

A.2.8 How optimal organisational structures vary with transaction costs

The optimal choice of organisational structure reflects the desire by the parties to minimize transaction costs. Figure A- 2 shows that as transaction costs change, so does the least cost organisation structure. The Figure shows that increasing levels of uncertainty, asset specificity and measurement costs will increase transaction costs and drive market participants towards more integrated forms of organisation.

Figure A- 2 Comparison of costs of organisation models as the dimensions of transactions change



A.3 The energy markets framework as an incomplete regulatory contract

The energy markets framework can itself be viewed as an "incomplete regulatory contract." That is, the degree of completeness of the regulatory contract itself should be chosen by the regulator so as to minimise the transactions cost of regulating market exchange.

In other words it is neither possible nor desirable to achieve "certainty" by designing a complete regulatory contract with all contingencies clearly identified. As Goldberg, 1976, p.426) has explained: "Many of the problems associated with regulation lie in what is being regulated, not in the act of regulation itself."

This is because all future contingencies may not be foreseen at the time the regulator proposes a contract, and because new information becomes available as the regulator learns about how the market responds to regulation. As a result, renegotiation of the contract is potentially valuable; it can improve *ex post* market efficiency.

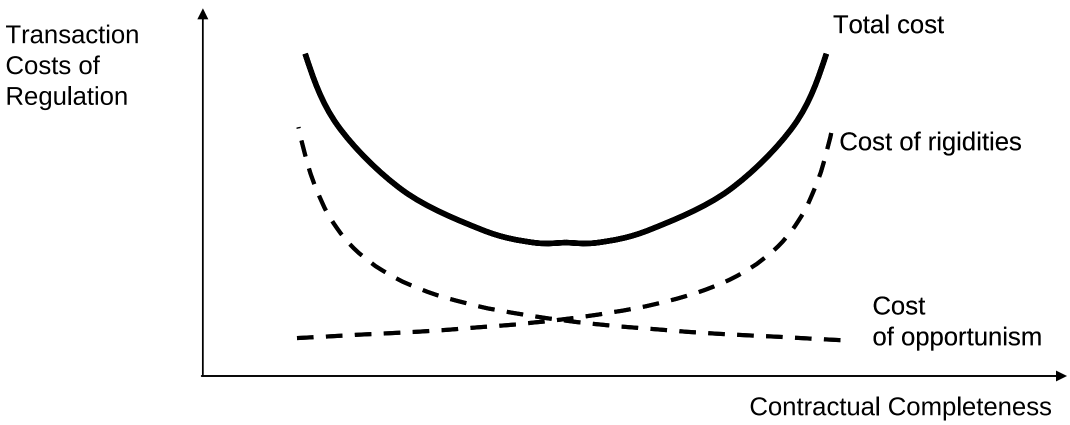
A key goal of regulation is an *adaptively efficient* energy market that over time will provide a framework for organisational and product innovation – and allow failures to disappear. It is one thing to get the framework "right" at a moment of time; it is something else to create a framework that is effective over time.

Following Saussier (2000), contract design decisions involve a trade-off between:

- Specification costs and rigidities associated with detailed performance obligations impacting uncertain or complex transactions, and
- Greater flexibility but higher expected cost of opportunism *ex poste* with less definite regulatory provisions.

Figure A- 3 below illustrates how the drivers of transaction costs – cost of rigidities versus cost of opportunism – play out as the completeness of the contract is increased.

Figure A- 3 Transaction cost versus contract completeness



The competing hazards are opportunistic behaviours of market participants (or public agencies) on the one hand, versus the hazard of maladaptation that come with inflexible regulation on the other.

In this context the regulator must be prepared for the continuous negotiation processes which are a mechanism for dealing with contract incompleteness. The all-important role of regulation as an enabler of low-carbon business strategies means that many companies will try to influence its design, at the level of both fundamental policy principles and tactical regulatory instruments (Enkvist et al, 2008).

Based on MMA's assessment of the key factors driving energy markets over the short to medium term, energy market performance may benefit from the CPRS/RET providing more certainty in the price of carbon, while the energy market framework relaxes other constraints so as to facilitate the structural adjustment process.

A.4 Analysing organisational structure in energy markets

A.4.1 Integration as a response to higher transaction costs

Interpreted broadly, vertical and horizontal integration can reduce coordination problems emanating from a wide variety of sources – asymmetric information, economic spillovers, investment externalities, simple coordination of the left-hand-knowing-what-the-right-hand-is-doing kind, and others. The advantage of integration is that it harmonizes interests (or reconciles differences, often by fiat) and permits an efficient (adaptive, sequential) decision process to be utilized.

There are a number of circumstances that lead to greater integration and industry consolidation. Following Stuckey and White (1993), there are four reasons why firms might want to vertically integrate – as a response to higher transaction costs:

1. The market is becoming too risky and unreliable — it is "failing."
2. Companies in adjacent stages of the industry chain are building more market power than companies upstream or downstream of them.
3. Integration would create or exploit market power by raising barriers to entry.
4. The market is nascent and the company must forward integrate to develop a market, or the market is declining and "independents" are pulling out of adjacent stages.

In contrast the work of Dyer and Singh (1998) on the Japanese auto industry identifies five ways in which companies can achieve lower transaction costs and so avoid the necessity to integrate ownership:

1. Engage in repeated transactions with a small set of suppliers / customers to facilitate cooperative adaptation to a changing market;
2. Develop economies of scale and scope by transacting with a small supplier group (high volume of exchange between transactors);
3. Establish extensive inter-firm information sharing and so reduce asymmetric information and the scope for opportunistic behaviour;
4. Use non-contractual, self-enforcing safeguards(i.e., goodwill and trust) over an indefinite time horizon (whereas contracts are effective for a finite time horizon);
5. Invest in co-specialised assets to increase productivity / quality / reliability.

The approach described by Dyer and Singh is also known as "quasi vertical integration" since it achieves the benefits of integration without the diseconomies of large-scale organisation.

A.4.2 Contracting in energy markets

Based on extensive empirical work described below, the key findings on energy market contracting are as follows:

1. When relationship-specific investments matter more, contracts will have a longer duration, so as to avoid hold-up problems.
2. Contracts will be less complete when the environment is more uncertain and complex, and when opportunistic behaviour is less likely.
3. When quasi-rents are large, sometimes even long-term contracts will not suffice, and vertical integration will take place. (Quasi rents are the returns to temporarily specialised productive services).
4. Price renegotiation provisions are more useful when the environment is more uncertain or the contract has a longer duration.
5. Spot market arrangements are more likely when the local market is thicker.

A.4.3 Evidence on contract duration

Joskow (1987) examined the relationship between contract duration and asset specificity using evidence from long-term contracts between U.S. coal mines and electric utilities. He found that coal contracts in the West, where coal is of variable quality and mines are large and geographically dispersed, are 11 years longer on average than in the East, where a large number of small mines produce coal of relatively uniform quality. Contracts with mine-mouth plants are 12 years longer on average, and contract length increases by 13 years for each additional million tons of coal contracted for delivery (which reflects the size of the investment in transaction-specific assets).

Crocker and Masten (1988) addressed the effects of uncertainty on contract duration using data on long-term natural gas contracts. They found that price regulation of natural gas reduced the ability of the contracting parties to adapt long-term contracts to reflect changing circumstances, and reduced contract length by an average of 14 years. Uncertainty caused by the 1973 Arab oil embargo further reduced contract length by three years.

Other contract features include “take-or-pay” provisions or other penalties for refusing to buy, to protect the seller’s investment. For example, Goldberg and Erickson (1987) examined long-term contracts between petroleum coke refiners and their customers. Because of high storage costs, a buyer’s failure to take delivery can disrupt operations at the refinery and impose costs on the seller. Furthermore, high transportation costs encourage customers to locate near suppliers and limit the possibility for sales to alternative customers. As a result, contracts tend to be long-term, with minimum purchase requirements and substantial financial penalties for non-removal by buyers. Many contracts also provided for price flexibility by using indices tied to the price of crude oil or allowing negotiation within minimum and maximum prices.

A.4.4 Evidence on contract design for flexibility

Masten and Crocker (1985) interpret take-or-pay provisions (requiring minimum payments even if delivery is not accepted) in natural gas contracts as damages for breach of contract by the buyer. Breach of contract is efficient if the buyer gains more than the seller loses, which will be the case if the minimum payment compensates the seller for the difference between the contract price and its next-best sale opportunity. The authors found that the size of take-or-pay requirements were negatively correlated with the number of pipelines serving the field (reflecting alternative sales opportunities), and positively correlated with the number of sellers in the field (which reduces the value of retaining gas in the ground for future sales, since the sellers are drawing on a common pool of gas).

Price adjustment provisions can facilitate the use of long-term contracts by mitigating the effects of price uncertainty. Although fixed-price contracts are easier to administer and are associated with better pre-contract information and less opportunism, Goldberg (1985) argued that they can result in an excessive pre-contract search for information about future prices and costs, and in poor performance and post-agreement jockeying to force a renegotiation if they are used in circumstances where prices are uncertain. There are also trade-offs involved with the choice of price adjustment mechanisms, which can be based on market price indices or allow for some degree of renegotiation. Less formulaic price adjustment mechanisms are more flexible, but they also allow for greater opportunism during renegotiation.

Joskow (1988) and (1990) examined how well price adjustment mechanisms related to production costs in long-term coal contracts reflect market prices over time. He found that these mechanisms worked well in the 1970s, but diverged from the 1980s market price of coal, which fell while production costs continued to rise. However, relatively few of these contracts were renegotiated, possibly because of threat of legal sanctions. There may also have been less competitive pressure for regulated or local-government-owned electric utilities to minimize costs.

However, in many cases, there is no relevant market price or index that can serve as a guideline for price adjustment mechanisms. Crocker and Masten's (1991) study of natural gas contracts found a trade-off between very precise agreements that constrain opportunism and loose agreements that permit adjustment to changing economic circumstances. More-flexible price renegotiation was associated with longer contract duration and greater price uncertainty, as well as larger minimum payment provisions. This suggests that quantity guarantees are a substitute for stricter price adjustment mechanisms.

A.5 Frameworks for Analysing Strategy of Energy Market Participants

Properly designed and implemented CPRS/RET regulations can trigger innovation that may partially or more than fully offset the costs of complying with them. Enkvist et al (2008) identify the following ways in which companies will reposition themselves to seize the opportunities of a low-carbon future:

- **Optimizing current assets and products:** Given a relatively slow turnover in the capital stock of these and other heavy industries, a significant part of their response will be to optimize the carbon performance of existing assets.

- **Reduce costs through carbon-efficient operations:** Many companies can reduce energy and carbon intensity, while becoming more cost competitive to boot.

- **Reposition the portfolio:** Companies can reap strategic advantages by repositioning their energy asset portfolios. They could sell plants likely to be less competitive if carbon regulation is introduced or reinforced. They could buy assets that will benefit from public-policy actions. And they could shift the mix of their investments toward less carbon-intensive plants and technologies.

- **Building new low-carbon businesses:** In parallel with efforts to optimize the existing infrastructure's carbon performance, there will be major moves to develop radically more effective low-carbon solutions for new infrastructure.

A.5.1 Positioning: cost leadership versus differentiation

Michael Porter's model of competitive strategy posits five forces impacting on a Firm's strategy – bargaining power of **customers** and **suppliers**, threat or presence of **substitutes** and **new entrants**, and **rivalry between industry competitors,** (Porter, 1985). Exogenous forces such as technology and regulation combine with these endogenous forces to determine outcomes in the industry.

In this framework, the emphasis is on positioning the firm in an industry and shielding it against the five competitive forces, such as through the creation of entry barriers or mobility barriers which limit a firm's ability to move within an industry. High transaction costs are a pre-condition for strategizing aimed at exploiting market power through entry and mobility barriers.

Cost leadership and product differentiation are considered the two most important generic positioning strategies. Different survival strategies can coexist in an industry — for example, one group of firms may survive with "cost leadership" while the other group may survive by pursuing "differentiation" with extensive R&D or marketing.

A.5.2 Cost leadership strives to produce goods or services more cheaply

Cost leadership stresses efficient scale facilities, the pursuit of cost reductions in production and distribution, and the minimization of expenses of product R&D, services, selling and advertising. Cost leaders try to supply a standard, no-frills, high-volume product at the most competitive possible price. They do very little product innovation since this is disruptive of efficiency. The innovations of competitors will only be imitated after a considerable risk-reducing lag. Process R&D, backward vertical integration, and production automation may be pursued to reduce costs.

A.5.3 Differentiation aims to create a product that is perceived as uniquely attractive

Differentiation emphasizes strong marketing abilities, creative, well-designed products, a reputation for quality, a good corporate image, and strong cooperation from marketing channels. In the context of CPRS/RET differentiation involves increasingly creative departures from historical industry practices such as the following:

1. Introducing new technologies to create a significant improvement in process efficiency
2. Innovating with new products - creative ideas that bring in revenue, but don't change existing business models
3. Creating new business models - in the design of the end-to-end value chain architecture; in the conceptualization of delivered customer value; and / or in the identification of potential customers.

A.5.4 Adaptation

The firms that will prosper in a carbon-constrained world will be those that are:

- Early to recognise its importance and its inevitability;
- Foresee the implications for their industry segment;
- Align their strategy and organisation to meet the challenges ahead; and
- Take appropriate steps well in advance.

Faced with the need to adapt to an uncertain future, real option thinking is a way of framing business and investment strategy — as the creation of options and opening up new choices in an uncertain world.

A.5.5 In times of industry change, real options become more valuable

Grounded in the basic intuition that decision makers seek to “keep options open” in situations that involve an uncertain future, real options advises to move forward in stages when steering investments in an uncertain future.

In the case of investment in CO2 emissions reduction, the real option approach would work as follows: Given an uncertain CO2 price trajectory — and the possibility that a better technology will be available at some uncertain date in the future — firms should consider a variety of future carbon price scenarios and potential adaptive strategies; favour actions that are robust to carbon price uncertainties; favour exploratory actions that yield useful information; probe and experiment through R&D; monitor results and invest in stages as carbon market conditions unfold.

The real options framework explicitly recognises that value is created through identifying, creating, owning, managing, and exercising options such as the following:

- Planting seeds: Experiment strategically by making a series of small investments, before making the big ones;
- Learning actively: Decisions on a program do not always have to be made up front; conduct tests and capitalise on learnings;
- Building ramps: Embed options to defer or accelerate, to switch direction at any project stage;
- "Failing fast:" Build-in flexibility to abandon if conditions weaken.

A.6 References

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