ROAM CONSULTING

ENERGY MODELLING EXPERTISE

ROAM Consulting Pty Ltd

A.B.N. 54 091 533 621

Report (Emc00007) to

AEMC

NATIONAL ELECTRICITY MARKET DEVELOPMENT

Market impacts of CPRS and RET

17 December 2008

VERSION HISTORY

Version History					
Revision	Date Issued	Prepared By	Approved By	Date Approved	Revision Type
0.5	2008-11-04	Richard Bean Joel Gilmore Jenny Riesz Andrew Turley Ben Vanderwaal	Ian Rose	2008-11-04	Draft
1	2008-11-13	Richard Bean Joel Gilmore Jenny Riesz Andrew Turley Ben Vanderwaal	Ian Rose	2008-11-13	Report
1.1	2008-11-14	Richard Bean Joel Gilmore Jenny Riesz Andrew Turley Ben Vanderwaal	Ian Rose	2008-11-14	Final revisions
1.2	2008-12-16	Richard Bean Joel Gilmore Jenny Riesz Andrew Turley Ben Vanderwaal	Ian Rose	2008-12-16	Version for public release
1.3	2008-12-17	Richard Bean Joel Gilmore Jenny Riesz Andrew Turley Ben Vanderwaal	Ian Rose	2008-12-17	Final version for public release

EXECUTIVE SUMMARY

This report discusses issues surrounding the introduction of the RET and CPRS in the Australian electricity market that have been revealed by ROAM's modelling. The material issues are as follows.

Review of modelling studies

Three main reports have been identified by ROAM to provide insight into the impacts of the CPRS and the RET upon the electricity sector. These are:

1. **Impacts of the Carbon Pollution Reduction Scheme on Australia's electricity markets**, Report to Federal Treasury by *McLennan Magasanik Associates (MMA)*. 27th October 2008
    - This report provided the main input on the electricity sector to the Garnaut Review and Treasury's "Australia's Low Pollution Future" report.
2. **The impact of an ETS on the energy supply industry**. Modelling of the impacts of an emissions trading scheme on the NEM and SWIS. Report by *ACIL Tasman* to the Energy Supply Association of Australia (ESAA), June 2008.
3. **Market modelling to assess generator revenue impact of alternative GHG policies.** Report by *CRA International* to the National Generators Forum, June 2008.
    - This report is not publicly available, but is reviewed in: **Bringing specific company economic perspectives to bear on the ETS design**. Report prepared for the Business Council of Australia by *Port Jackson Partners Limited,* 21 August 2008.

Modelling results are highly sensitive to the demand projection assumed as input. In addition, demand projections have high uncertainty, and vary widely between studies. CRA's study shows very little demand reduction in response to the CPRS, whereas MMA's study forecasts a very large reduction in demand. ROAM considers this the most significant difference between studies. ROAM's modelling suggests that MMA's assumed level of demand reduction in response to the CPRS is highly unlikely. This is a fundamental assumption that significantly affects all results of the study.

MMA's study challenges the common belief that gas-fired generation will increase significantly under the CPRS, due to fuel switching from coal-fired generation. MMA's results instead suggest that gas-fired generation may increase under some scenarios, but may decrease in others. This is partly due to the reduced demand projections assumed by MMA and the assumed high gas cost projections. ROAM's modelling supports MMA's finding. Depending upon demand projection assumptions, the level of the emissions permit price, the level of the gas price and the contribution of renewable generation, gas-fired generation may play a large or small role in Australia's electricity future.

MMA's study finds that the emissions permit cost will be entirely passed through into the wholesale pool price. ROAM's modelling suggests that the proportion of the emissions permit price that will appear as an uplift in the pool price will vary from 80% to 120% depending most critically upon:

1. The region

2. The emissions permit price
3. The ability of generators to exercise market power in strategic bidding

Types of renewable generation

As the lowest cost form of renewable generation, ROAM expects that the majority of the RET will be met by wind generation. SA, VIC, WA and TAS have excellent wind resources, where the main limitations on development are likely to be the peak demand in South Australia (evidence suggests that up to 20% of the peak demand in each region may be met without significant problems due to voltage stability and intermittency) and frequency control in Tasmaina. Fulfilment of the MRET has also limited development in wind generation to date, but suspended projects are expected to be renewed with the onset of the expanded RET.

Sugar cane bagasse generation has the potential to provide up to 660MW to Queensland, and has the potential to be sufficiently supported by the expanded RET. Investment in bagasse generation has been limited to date due to the small number of businesses in the sugar industry, and their relative lack of experience in the electricity generation sector. Linkages with the sugar market, and blow-outs in capital costs of past projects have also inhibited development. A limited amount of renewed interest is anticipated under the expanded RET.

Solar PV is an extremely expensive form of large scale power generation, and is not expected to contribute substantially to the expanded RET. Concentrating solar PV may show more potential, but is expected to remain significantly higher cost than wind and bagasse generation to 2020.

Solar thermal generation shows greater potential, but requires substantial research investment to bring down costs to competitive levels. Very significant emissions permit prices will also be required in addition to the RET for this technology to compete with conventional technologies.

All external studies reviewed in this report assume that wind generation will be the most significant contributor to the expanded RET. Most studies also assume a significant contribution from geothermal energy, although ROAM's research suggests that this technology is unlikely to be commercially feasible on a large scale by 2020, and forecasts a much lower contribution. Conversely, most studies take a highly conservative view of solar energy, whereas ROAM's research suggests that solar thermal technology shows great promise and could be a significant contributor to the expanded RET. Biomass is assumed by all studies to play a moderate role.

Transmission congestion

ROAM considers transmission congestion to be a major area for consideration when implementing the CPRS and the RET. ROAM is uniquely positioned to comment on transmission congestion, since ROAM's *2-4-C* model is the only NEM model that takes sophisticated modelling of transmission constraints into account. This is evident due to the lack of modelling results from other parties covering this particular topic.

ROAM's modelling shows that inter-regional transmission flows change significantly with the growth of the RET. This suggests that the amount of renewable generation anticipated to enter the market will have a significant impact upon inter-regional transmission flows, and should be the subject of significant further analysis. Substantial inter-regional transmission upgrades may be required to facilitate the introduction of significant quantities of renewable energy.

The incidence of congestion over most intra-regional flowpaths has been forecast to increase significantly by 2020, both under the RET and in the reference case (without the RET). This is due to increasing customer load, and a large amount of new plant locating in a transmission grid that is essentially constant. On some flowpaths, congestion reduces over time, which is likely due to increases in congestion elsewhere which prevent that flowpath congesting as significantly.

In the RET case, increasing congestion is most prevalent on the SESA-VIC flowpath and is also significant on the MEL-NVIC, NVIC-SNY and NNS-SEQ/NNS-SWQ flowpaths. Wind generation is the key factor here, although new thermal generation will play a role.

Renewables, and particularly intermittent renewables exemplified by wind, are disadvantaged by location, lack of transmission, lack of native load, and drive lower pool prices in the regions where they are most likely to develop. Hence the amount of wind that may otherwise be market competitive is unlikely to be developed, leading to second order wind resources taking their place. To reduce this, steps need to be taken to avoid congestion, particularly between regions. Also, the effects of large quantities of wind on Marginal Loss Factors may be a further deterrent. Studies need to be undertaken to describe the tradeoff between expanded regulated transmission infrastructure (which should be a natural outcome of valuing losses more highly in the regulatory test of new lines), versus locating wind projects in areas where the wind resource is poorer but the transmission grid stronger.

The key effect of the CPRS on transmission congestion is to reconfigure 'established' flow patterns between the regions of the NEM, and hence result in different patterns of congestion. However, the CPRS does not necessarily drive increases in transmission congestion in the NEM.

For OCGTs, the benefit from the CPRS is marginal, since they are less efficient than black coal fired generators, which offsets to a degree the lower emissions of gas relative to coal. Also, the RET scheme will not be helpful as it is likely to lower the incidence of high pool prices relative to without RET, meaning there is less opportunity for a peaking plant to run and hence recover its fixed costs. Therefore, the incentives for OCGTs to develop to support intermittent renewables will be weak.

Interaction of the CPRS and the RET

The CPRS and the RET are expected to create or significantly expand markets for emissions permits, gas and RECs. These markets will interact strongly through with the electricity market, potentially with unexpected consequences and subtleties.

The conventional wisdom is that renewable technologies will become more competitive under the CPRS. However, whilst renewable technologies remain dependant upon the RET for support, they are unlikely to benefit from the CPRS. Very high emissions permit prices ($40 to $60 /t$CO_2$) will be required for renewable generators to be advantaged by the CPRS beyond the support of the RET.

The interaction of the RET and the CPRS is a topic that is poorly understood, and requires substantial further investigation. Unexpected subtle interactions are possible that may skew market outcomes.

Western Australian and Northern Territory Electricity Markets

Due to the different market rules and operation in WA, there is potential for the CPRS and RET to impact more strongly on its operation. In addition, the extensive wind resources in WA combined with the limited grid size are likely to cause transmission congestion due to intermittency.

The NT system is unlikely to see significant development in wind, but is likely to instead utilise the excellent solar resources in that region. The solar resources in the NT may provide further incentives for the interconnection of the system with Queensland through Mt Isa.

Interaction of gas and electricity

If the CPRS has the effect of increasing Australia's reliance on gas for electricity generation, it is important to consider the implications of greater connectivity between the gas market and the electricity market.

Historically, gas supply has been prone to catastrophic single point failures. The increasingly close integration of the gas and electricity markets under a CPRS may mean that catastrophic single point failures in gas supply translate into decreased reliability in the electricity market. Expected increased investment in gas pipelines may offset this effect. Gas availability during high demand (very cold) times may also become a significant issue.

Although projected gas usage is highly uncertain, there is a possibility that the CPRS will drive significantly increased investment in gas generation. This may cause gas delivery problems, if the pipeline infrastructure is not capable of meeting daily and half hourly periods of peak gas demand.

The disjoint between gas and electricity regulation creates opportunity for gas developers rather than transmission providers. In addition, the risks associated with an expanding gas network rather than transmission are relatively low.

The introduction of the CPRS should however add additional market benefits for transmission development. By having a price for emissions, transmission should accrue benefits for expanding the capacity for low-emission energy reaching the market. Furthermore, an emissions price will increase the value of those benefits derived through savings in transmission losses.

Although an expanded gas network may encroach upon transmission development, the diversification of the generator portfolio should reduce the impact of transmission failures and transmission congestion. Furthermore, the effect of catastrophic single point failures along gas pipelines will reduce with an expanded gas network. Pipeline development is therefore not considered to be a significant risk to the stability of the transmission network, so long as sufficient transmission developments can proceed to strengthen the transmission backbone.

The RET and the CPRS may be in potential conflict as the RET is likely to need electricity transmission to support renewables, whereas the CPRS scheme is likely to need expanded gas pipeline development to support expanded use of gas.

If gas prices rise sufficiently, the CPRS will be inadequate to drive investment towards intermediate and baseload gas technologies. Future gas prices are therefore an essential consideration. There is great uncertainty regarding future gas prices, related to uncertainty over the development of a LNG export industry, driving domestic gas prices towards parity with international prices. Projected gas prices in other studies for 2020 range between \$4/GJ -8\$/GJ. Prices in this range will have widely different consequences for the operation of the electricity market under the CPRS.

Price volatility

As would be intuitively expected, the RET increases price volatility. This is due to the entry of large quantities of intermittent wind generation.

The impact of the CPRS upon pricing outcomes is more difficult to assess, due to uncertainty over the amount of market power that generators may hold under varying levels of carbon price. At the extreme where generators are forced to bid close to their short run marginal costs, price volatility is significantly reduced under the CPRS.

Impacts of the CPRS and RET on generation by type

The trading strategies of existing generators will be significantly tested by the introduction of the CPRS, especially when the price for emissions permits rises to high levels. With a \$35/t CO_2-e emissions price, the merit order of combined cycle plant and brown coal may switch, if plant are bid to ensure that they run only when the spot price meets or exceeds the short run marginal cost.

For example, a typical new entrant combined cycle plant should have a short run marginal cost in the order of \$40/MWh. On the other hand, Hazelwood power station, the most emissions intensive plant in the NEM, will be severely impacted by a high carbon price. Hazelwood has an emissions intensity above 1.0t/MWh, which may push its short run marginal cost up above \$50/MWh with a \$35/t CO_2-e emissions price.

CCGTs are likely to be beneficiaries of the CPRS as they are both fuel efficient and use fuel with low emissions intensity. The number of CCGTs is likely to increase but will be limited by high gas prices and the lack of volumes needed if there is significant demand response to high prices stimulated by the CPRS.

For OCGTs, the benefit from the CPRS is marginal, since they are less efficient than black coal fired generators, which offsets to a degree the lower emissions of gas relative to coal. Also, the RET scheme will not be helpful as it is likely to lower the incidence of high pool prices relative to without RET, meaning there is less opportunity for a peaking plant to run and hence recover its fixed costs. Therefore, the incentives for OCGTs to develop to support intermittent renewables will be weak.

Combined shifts in demand and wind generation within a single half hour period in South Australia were found to be up to 800 MW for a projected 2016 year with 1600 MW installed wind. This requires a rapid response from peaking generation to maintain system reliability. However, an OCGT is only likely to earn revenue from such events if it already happens to be synchronised and generating.

There is currently only very limited opportunity for peaking plant to take advantage of revenue streams sourced from ancillary services markets. However, considerable advances have been made in short-term wind forecasting, and accuracy may be expected to improve further in the near future. Therefore it may be possible to define a new FCAS service specified over a longer timeframe than current services to respond to forecast wind variability. This may help address both the profitability of standby plant such as OCGTs and provide a means to address some of the negative market effects of higher wind penetration.

Profitability analysis of coal fired power stations

ROAM has analysed the potential for forced retirement of each individual coal-fired power station in the NEM, due to competitive forces under the RET, or loss of production or revenue under the CPRS. ROAM's results show that only old, inefficient plant in each region are considered potentially unviable within a emissions constrained market, even under a moderately high emissions permit price of $40/t$CO_2$. None are threatened by the RET.

ROAM's modelling consistently shows that individual coal-fired generators will be affected very differently by the CPRS. Some will show severe reductions in volume (and therefore revenue). Others, however, are likely to show increased volumes (compensating in part for the reduced volumes from the most emissions intensive plants). This combined with the expected increase in the pool price will therefore mean that some coal generators experience very mild revenue impacts.

The impacts on generators cannot be determined from their emissions factors alone, since the outcomes are heavily dependent on transmission limitations between regions. It is therefore incorrect to assume that all brown coal generators will be more severely impacted than black coal generators (since brown coal generation is exclusively located in

Victoria). Some highly emitting coal generators are likely to show increased volumes under the CPRS, to compensate for the reduced volumes of other plants in that region.

ROAM's results suggest that only the most inefficient plant are those likely to be threatened by an emissions reduction scheme. This plant tends to be close to the end of their useful life, and unless overhauled would tend to be candidates for retirement even in the absence of the CPRS. Hazelwood for example, built in the 1960s, would be over 50 years old when emissions prices are expected to rise to levels where it may lose money. Therefore, although some plant may be unviable at high emissions prices, this plant would likely require significant capital work to extend the life of the plant (to improve the efficiency of the station), or would be shut down and replaced with newer technologies.

Contrary to popular belief, there is no single region that is more affected than another by the CPRS, since transmission limitations between regions will ensure that some coal fired base load generators remain competitive in each region. Inter-regional transmission limitations serve to 'protect' the profitability of coal-fired generation, maintaining market volumes, whilst reducing the effectiveness of the CPRS at mitigating emissions.

ROAM's modelling suggests that in the medium term, all plant should be considered profitable with mild emissions prices. This would depend upon their capacity to provide a more flexible mode of operation, as identified by some stations losing a material proportion of generation due to the effects of the varying increase in costs associated with emissions permits. In the longer term, as the price of permits rises to high levels, older less efficient plant may lose competitive advantage, losing generation to other coal units or new or existing gas plant, and may prove unprofitable. The market must be capable therefore of providing enough incentive for high capacity factor plant such as low emissions coal or combined cycle gas to enter the market to replace those unprofitable power stations. If the wholesale pool price does not provide sufficient stimulus for this development, the AEMC and NEMMCO must find alternative avenues to ensure system security.

Some coal fired generators may have to cycle to avoid excessive penalties from carbon price. This may lead them to shut down overnight, which will increase their operating costs through use of oil for starting and also potentially increase Operations and Maintenance costs, or risk lower reliability. Transmission limitations between regions will ensure that some coal fired base load generators will remain competitive in each region, irrespective of the emissions intensity of the plant. To maintain the viability of other threatened generators, consideration could be given to modifying ancillary service payments to allow them to obtain a larger revenue proportion from FCAS and NCAS services to compensate for loss of revenue from MWh produced. This would allow their volumes to decrease, thus reducing emissions, while underpinning their revenue levels to some extent through a default 'capacity' payment, thus ensuring they are available to contribute to reliability when needed.

The primary limitation on the efficacy of the RET and CPRS to fulfil their intended function results from inadequate transmission capacity, particularly between regions of the NEM. This will be manifested in increased pool price volatility and transmission congestion, and potentially on reliability, depending on whether generators are forced to retire prior to sufficient new generating plant entering the market. The CPRS will also encourage more efficient new generators to enter, rather than the more flexible OCGT capacity that would support intermittent renewables.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1) ABBREVIATIONS

CCGT	Combined cycle gas turbine
CPRS	Carbon Pollution Reduction Scheme (Australia's proposed national emissions trading scheme)
DCC	Australian Government Department of Climate Change
ETS	Emissions Trading Scheme
EU ETS	European Union Emissions Trading Scheme
LRMC	Long run marginal cost
M10	NEMMCO load growth forecasts, with medium growth, and a 10% probability of exceedence climatic forecast consistent with one in 10 year adverse conditions.
NEM	National Electricity Market – the interconnected electricity grid on the east coast of Australia, incorporating Queensland, New South Wales, Victoria, Tasmania and South Australia.
OCGT	Open cycle gas turbine
P.O.E.	Probability of exceedence – in the context of peak demand, it represents the probability that the given demand level will be exceeded for at least one half an hour per annum (one trading interval).
RECs	Renewable Energy Certificates
(M)RET	(Mandatory) Renewable Energy Target (Australia's proposed expanded renewable energy scheme, which aims to source 20% of Australia's energy from renewable sources by 2020.)
SRMC	Short run marginal costs
SWIS	South-West Interconnected System – the interconnected electricity grid in the south-west of Western Australia. The market for the SWIS is the WEM
WEM	Western Australia Wholesale Electricity Market

2) BACKGROUND

The Australian Energy Market Commission has been directed by the Ministerial Council on Energy (MCE) to review possible impacts on the energy market of the proposed Carbon Pollution Reduction Scheme (CPRS) and enhanced national Renewable Energy Target (RET) frameworks. The purpose of the Review is to advise the MCE on whether changes to energy market frameworks are warranted, on the basis that they will better promote the market objectives of providing efficient, secure, safe, and reliable supplies of electricity and gas in the long term interests of consumers.

The review is to consider all states and territories, and provide advice on what, if any, changes are needed to the energy market frameworks, including how these changes should be implemented. One of the key effects of the introduction of the CPRS and RET in terms of energy market frameworks is a change to the economics of generation investment, and as such, a key element of the Commission's analytical work will necessarily relate to the behaviour of electricity generators.

AEMC Scoping paper

The AEMC has recently released a Scoping Paper[1] seeking stakeholder feedback on a variety of issues.

According to the Scoping Paper, the AEMC is particularly concerned with the material aspects of the costs of managing congestion, and the factors influencing the price of contracts in the short and medium term. Questions concerning these issues generally begin with "How material are the risks …" and the review may ultimately modify the National Electricity and National Gas Rules to help control some of the risks which may arise as a result of the introduction of the CPRS and expanded RET.

Market Objectives

The National Electricity Market Objective is: "to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, safety, reliability and security."[2]

The original national electricity market objectives in more detail are as follows:

- the market should be competitive;
- customers should be able to choose which supplier (including generators and retailers) they will trade with;
- any person wishing to do so should be able to gain access to the interconnected transmission and distribution network;
- a person wishing to enter the market should not be treated more favourably or less favourably than if that person were already participating in the market;
- a particular energy source or technology should not be treated more favourably or less favourably than another energy source or technology; and
- the provisions regulating trading of electricity in the market should not treat intrastate trading more favourably or less favourably than interstate trading of electricity.

Outhred (2004)[3] notes that none of these objectives are environmental, despite the original 1991 brief "to encourage and coordinate the most efficient, economic and environmentally sound development of the electricity industry".

The National Gas Market Objective is very similarly worded: "to promote efficient investment in, and efficient operation and use of, natural gas services for the long term

[1] Review of Energy Market Frameworks in light of Climate Change Policies, Scoping Paper. 10th October 2008, AEMC.

[2] http://www.aemc.gov.au/whataemcdoes.php

[3] http://www.ceem.unsw.edu.au/content/documents/200404AssessingNEM0404.pdf

interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."[4]

3) Scope

This report provides advice concerning the function of the electricity market (NEM, WA and NT markets) under CPRS and expanded RET, with particular focus on the following issues.

- Transmission limitations
- Potential for rising gas prices
- Energy efficiency measures and proliferation of demand side management
- Interaction between the RET and CPRS
- Distribution and type of renewable technologies stimulated by the RET and CPRS
- Price volatility.

These topics are closely related to those discussed in the scoping paper. For example, transmission limitations are related to network congestion (Issue 6 in the Scoping Paper), and price volatility is linked to the price of contracts in the retail market, (Issue 7 in the Scoping Paper).

As well as providing a review of its extensive modelling activities relating to the issues of interest to AEMC, ROAM has also performed a review of other modelling work on the RET and CPRS and their forecast effects on the electricity and gas networks.

4) Studies by other parties

Modelling studies reporting on the impacts of the CPRS and RET on the electricity market in Australia are summarized here.

[4] http://www.austlii.edu.au/au/legis/qld/bill_en/ngb2008235.txt/cgi-bin/download.cgi/download/au/legis/qld/bill_en/ngb2008235.txt

Box 1 – Significant reports on the impacts of climate policy on the electricity sector
Three main reports have been identified by ROAM to provide insight into the impacts of the CPRS and the RET upon the electricity sector. These are: 1. **Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets**, Report to Federal Treasury by *McLennan Magasanik Associates (MMA)*. 27th October 2008 • This report provided the main input on the electricity sector to the Garnaut Review and Treasury's "Australia's Low Pollution Future" report. 2. **The impact of an ETS on the energy supply industry**. Modelling of the impacts of an emissions trading scheme on the NEM and SWIS. Report by *ACIL Tasman* to the Energy Supply Association of Australia (ESAA), June 2008. 3. **Market Modelling to Assess Generator Revenue Impact of Alternative GHG Policies.** Report by *CRA International* to the National Generators Forum, June 2008. • This report is not publicly available, but is reviewed in: **Bringing specific company economic perspectives to bear on the ETS design**. Report prepared for the Business Council of Australia by *Port Jackson Partners Limited,* 21 August 2008.

4.1) IMPACTS OF THE CARBON POLLUTION REDUCTION SCHEME ON AUSTRALIA'S ELECTRICITY MARKETS

Report to Federal Treasury by McLennan Magasanik Associates (MMA). 27th October 2008

This report details the impacts of the CPRS and RET on the electricity generation sector. The objective of the modelling was to estimate the costs and benefits to the economy of a potential range of caps on emissions of greenhouse gases. The modelling was also designed to provide insights into other impacts on the electricity market.

This study provided the detailed bottom-up analysis of the electricity market included in the Treasury modelling[5], and in the Garnaut Review modelling[6].

Model:

MMA's bottom up model of the National Electricity Market (NEM), South West Interconnected System (SWIS) and the Darwin Katherine Interconnected System (DKIS).

Scenarios modelled:

Six scenarios were modelled:

1. ***Reference scenario:*** No emissions trading scheme, with Australia and the international community proceeding under business as usual.

[5] Australia's Low Pollution Future. The Economics of Climate Change Mitigation. Australian Government, The Treasury, 31 October 2008.

[6] The Garnaut Climate Change Review. Final report, October 2008.

2. ***Garnaut -10:*** An Australian emission trading scheme is adopted, commencing in 2013, with an emissions allocation that leads to a reduction in emissions of 10% on 2000 levels by 2020.
3. ***Garnaut -25:*** An Australian emission trading scheme is adopted, commencing in 2013, with an emissions allocation that leads to a reduction in emissions of 25% on 2000 levels by 2020.
4. ***CPRS only:*** An Australian emission trading scheme is adopted, commencing in 2010, with an emissions allocation that leads to a reduction in emissions of 5% on 2000 levels by 2020. The expanded RET is excluded.
5. ***CPRS -5:*** An Australian emission trading scheme is adopted, commencing in 2010, with an emissions allocation that leads to a reduction in emissions of 5% on 2000 levels by 2020. The expanded RET is included.
6. ***CPRS -15:*** An Australian emission trading scheme is adopted, commencing in 2010, with an emissions allocation that leads to a reduction in emissions of 15% on 2000 levels by 2020. The expanded RET is included.

Significant findings:

Prices:

- **Increase in wholesale electricity prices:** Wholesale prices increases by more than the value of the permit price in the NEM, particularly in the period before 2020. In the period to 2020, wholesale prices are expected to increase by around 50% for modest cuts in emissions to around 83% for the deepest cut in emissions. After 2020, prices are expected to rise by 122% to 172%, depending on the level of cuts required.

Emissions:

- **Emissions abatement vs carbon price:** As would be expected, the higher the permit price, the lower the level of emissions from the electricity sector. This trend is observed until the mid 2030s. Post 2030, the demand response becomes more significant.
- **Emissions trajectory:** Emissions from electricity generation stay flat until around 2030 under most scenarios. Over the long term, emissions are expected to reduce to below half of 2000 levels by 2050.
- **Abatement in the electricity sector:** The contribution of electricity generation sector to the abatement task is relatively modest over the next ten years, butthe sector makes a substantial contribution to abatement over the long term.
- **Sources of abatement:** In the near term, reduction in demand contributes around half of the emission reduction in all scenarios. Additional renewable energy generation also contributes to the near term abatement, with up to 40% of the abatement due to this source in the scenarios with the RET. Over the long term both these sources remain important, contributing one-third each to the abatement task. Carbon capture and storage is also an important source, also contributing one-third of the abatement in 2050.

Plant profitability and retirements:

- **Impacts of the CPRS and RET on gas-fired generation:** Gas-fired generation does not make a major contribution to the abatement task in scenarios with either a RET scheme or deep cuts early on. In other scenarios, a switch to gas fired generation is an important source of abatement in the period to 2030. But in all scenarios gas-fired generation is not a major contributor to abatement in the period after 2030.
- **Brown coal become the marginal generators**: Under the CPRS, Victorian brown coal generators set the price in many periods (instead of being base load plant and, hence, price takers as occurs without emissions trading). Because these generators set the price in the NEM and because they have high emission intensities (of greater than 1 t/MWh), electricity prices increase by the full amount of the increase in their short run marginal costs. This is aided by rising gas prices which prevent gas-fired plant from displacing the brown coal plant in mid merit even with relatively high permit prices. This ability to pass on their costs is also aided by their ability to manage their bids to maximise profits.
- **Coal generators to 2030**: Coal generation is likely to remain the dominant form of generation in the next two decades under the emissions trading scenarios modelled, with generation remaining stable at current levels.
- **Coal generators 2030-2050:** Even with a modest emission trading scheme, the proportion of coal-fired generation is expected to fall to around one-third by 2050 (to be generating at levels of one-half to two-thirds of current levels of generation).
- **Gas fired generation:** Gas fired generation is predicted to increase but not to increase its share of generation markedly. In the short term, the advent of emissions trading does help gas to increase its market share by 5%. However, over the long term the assumption that gas prices trend towards international benchmark prices and the change in electricity demand reduces the competitiveness of gas-fired generation.
- **Renewable generation:** Renewable energy generation is expected to increase markedly to contribute half of the generation mix by 2050.
- **Renewable generation under the CPRS without the RET:** Up until 2020, the increase in renewable generation is limited in scenarios with a CPRS only, except for the Garnaut -25 scenario where the high carbon prices encourage the entry of some wind generation and geothermal generation. In cases with the expanded RET, wind generation is expected to increase markedly in the period to 2020.

Other factors:

- **Electricity demand response to CPRS:** Whilst higher permit prices would put downward pressure on emissions from electricity generation, a switch to electricity in other activities can offset either partly or completely this reduction. For example, a switch to electric vehicles (in response to higher permit prices) will increase electricity demand. Industrial plant may also switch to electricity away from direct combustion in response to higher permit prices. This increase in electricity demand will put upward pressure on emissions. Thus, in some cases emissions can actually increase with higher permit prices (although overall emissions in the economy would be lower).
- **Availability of international offsets:** The availability of international offsets also affects the level of emissions in electricity generation. Thus, emissions from electricity generation are similar for the 10% and 5% mitigation scenarios over the

long term as the greater availability of international offsets puts a lid on the costs of permits in 10% scenario.

Limitations of MMA's modelling

The modelling conducted by MMA has a number of important limitations, aside from the uncertainty of the input assumptions. These include:

- Extreme peak demands are not fully weighted. Periods of extreme peak demands are known to be very important for the recovery of capital expenditure for peaking generation, and have a very significant impact on average pool prices.
- Marginal prices between regions are averaged for the purposes of estimating inter-regional trading resulting in a tendency to under-estimate the dispatch of some intermediate and base load plants in exporting regions such as Newport and Hazelwood in Victoria.
- MMA's model is relatively coarse grained, with extensive smoothing being necessary to produce realistic looking outcomes. The modelling approach is based on a screening tool for financial and strategic analysis, rather than a detailed replication of generator behaviour. This modelling approach is normally followed by review using a detailed probabilistic model.
- The model is not probabilistic (almost to the point of being deterministic in nature).
- Transmission networks are modelled in a very limited way, including only inter-regional interconnectors, and without dynamic limits.

ROAM's *2-4-C* model avoids these problems, being a highly detailed and probabilistic model. Smoothing and averaging is uncessary, and half hourly demand traces accurately represent the weighting of extreme price spikes. Monte Carlo simulation of outages is calculated, and the methodology is based upon the NEMDE market dispatch engine.

Most significantly, ROAM's model includes all major intra and inter regional transmission networks, based upon NEMMCO's annually updated ANTS constraint equations. This allows detailed assessment of transmission congestion issues.

4.2) BRINGING SPECIFIC COMPANY ECONOMIC PERSPECTIVES TO BEAR ON THE ETS DESIGN

Report prepared for the Business Council of Australia by Port Jackson Partners Limited, 21 August 2008.

Chapter 4 of this report reviews and compares the modelling of the electricity sector conducted by:

- ACIL Tasman, prepared for the Energy Supply Association of Australia (June 2008), The impact of an ETS on the energy supply industry.
- CRA International, prepared for the National Generators Forum (May 2008), Market modelling to assess generator revenue impact of alternative GHG policies.

The impacts on coal-fired generation assets are assessed, as well as the implications of price caps on retail electricity prices. The CRA report is not publicly available, but the ACIL Tasman report is summarised below.

4.3) THE IMPACT OF AN ETS ON THE ENERGY SUPPLY INDUSTRY

Modelling of the impacts of an emissions trading scheme on the NEM and SWIS. Report by ACIL Tasman to the Energy Supply Association of Australia (ESAA), June 2008.

This study models from 2008 to 2020 in a bottom-up approach.

Model:

PowerMark, ACIL Tasman's model of the NEM and the SWIS.

Scenarios Modelled:

1. Business as usual conditions
2. CPRS with a 10% reduction on 2000 emissions by 2020 (in the NEM and the SWIS). RET also included.
3. CPRS with a 20% reduction on 2000 emissions by 2020 (in the NEM and the SWIS). RET also included.

Significant Conclusions:

Prices:

- **Emissions price:** The modelling produced an emission permit price of $45/tonne CO2–e in the 10% case and $55/tonne CO2–e in the 20% case (in 2008 prices). The price rises fairly steeply at first in order to achieve the necessary level of retirements and replacement and flattens somewhat as it gets toward 2020.
- **Pool price increase:** NEM pool prices in real terms are projected to increase by 93% in the 10% case and about 105% in the 20% case over average levels to 2007.

Plant profitability and retirements:

- **Plant retirement:** The simulations indicate the forced retirement of about 6,700MW1 of base load plant in the 10% case to be replaced by 15,000MW (including 1,200MW in the SWIS) of new plant between about 2011 and 2020. This is a rapid rate of replacement which has not been achieved in Australia before.
- **Coal generators:** Most of the impact of an ETS is felt in Victoria, where the simulations indicate that most of the brown coal plant would close. In the 10% case, 3 out of the 4 major brown coal generation plants in the Latrobe Valley close as well as all of the coal generation in South Australia. In the 20% case these plants close plus one major black coal plant in each of Queensland and NSW.

- **Gas-fired generation:** Generation from retired coal plants is replaced by gas-fired combined cycle gas turbines (CCGTs) at high levels of energy conversion efficiency (in excess of 50%) and with about one third of the emissions intensity of brown coal generation and about one half of black coal.
- **Renewable generation:** With assistance from the RET scheme renewable generation also replaces some of this brown coal plant. Geothermal energy is assumed to reach 1500MW of installed capacity by 2020 and wind generation also plays a significant role in Western Australia, South Australia, Victoria and NSW.
- **Plant profitability:** An emissions trading scheme will change the merit order in the NEM, reducing volume and net revenue for incumbent fossil fuel generators by between 40% and 95%.
- **Coal fired generator asset value:** Using the net present value of returns per kW over the 10 years 2010 to 2020:
    - The average of this indicator for Victorian and South Australian coal fired generation indicated a fall of over 80% in asset value in the 10% case and over 90% in the 20% case.
    - For NSW coal generation the corresponding falls were close to 80% and about 90%
    - Queensland coal fired generation assets also reduced by 80% and almost 95% respectively in the 2 ETS cases.
- **Gas fired generator asset value:**
    - CCGTs on average reduced in value by about 40% in the 10% case and about 45% in the 20% case, largely because of the increase in the costs of gas for generation.
    - OCGTs reduced in value by 70% and about 80% respectively.
- **Renewable generator asset value:** The only asset group to increase in value between the BAU and the ETS cases was hydro, and this was by 20% and 40% respectively. The comparison between the BAU and ETS cases was not possible for other zero emission technologies, such as geothermal and wind, as they were not included in the BAU case but it is highly likely that an ETS would increase the asset values in these technologies as well.

Other factors:

- **Energy efficiency:** The study found that overall demand increased at rates 12% and 14% lower than BAU growth in the 10% and 20% emissions reduction scenarios respectively.
- **Capital investment:** The required capital investment in electricity generation increased from $13b in the BAU case to $33b and $36b to achieve 10% and 20% emissions cuts respectively, inclusive of the $23b investment required to achieve the MRET of 20% renewable electricity generation by 2020.
- **Gas demand:** Gas demand for electricity generation will increase from 139PJ in 2008 to 375PJ in the 10% case and 508PJ in the 20% case. Overall, the consumption pattern in eastern Australia reflects strong growth until around 2020, but then begins to decline as supply side constraints and rising gas prices see under-satisfaction of the market. This has potentially significant implications for new gas-fired power generation facilities: the risk of gas supply shortfalls within the

first decade after construction will need to be mitigated through measures such as long-term supply contracting.

- **Gas price:** Natural gas prices increased under all scenarios due to stronger links to global markets, and higher gas-fired generation and production costs.
- **Renewable Energy Target:**
    - The MRET of 20% renewable electricity generation by 2020 could be achieved, adding approximately 5% in real terms to retail tariffs by 2020.
    - The MRET renewable energy certificates will continue to be needed, as the modelled ETS carbon price was not sufficient to achieve the 20% renewables target.
    - The cost of achieving the 10% and 20% emission reduction targets using both an ETS cost of carbon and the MRET was higher than least cost, given that the model disclosed an abatement cost for wind generation that was \$10 to \$40 higher per tonne of CO_2 than gas-fired generation.

4.4) Market Modelling to Assess Generator Revenue Impact of Alternative GHG Policies

Report by CRA International to the National Generators Forum, June 2008.

Model:

CEMOS Model, with PEPPY and CONE modules

Scenarios modelled:

- Eight core scenarios, including two base scenarios, and six carbon constrained scenarios.
    - The two base scenarios assume no carbon target and no nuclear technology is available. The base scenarios differ by the level of capital costs assumed, with one assuming a low level of capital cost and the other one assuming a higher level of capital cost.
    - The six carbon constrained scenarios were selected from a combination of three carbon target levels, two capital cost levels and with and without nuclear.
- Four gas price sensitivities were modelled.
    - Three incorporated a step increase in gas prices in 2016-2050 of an additional 50%, 75% and 100% of the base case gas price applied to the moderate reduction scenario.
    - The fourth sensitivity involved a ramp up in gas price from an additional 25% of base case gas prices in 2016 to an additional 100% of base case gas prices by 2050.
- Two sensitivities on MRET were also examined. The current set of assumptions on renewables include long term resource limits of 7,500 MW for wind, 2,500 MW for biomass and 700 MW for hydro, as well as build limits of up to 150 MW/Yr for

geothermal. These assumptions do not allow the renewables target to be met. The two sensitivities analysed are:

- o A case where enough renewables entry was allowed to meet the target in each year
- o A base case assuming there is no expanded MRET.

Significant findings:

Since this report is not publicly available, the significant findings that may be included here are only those detailed in the Business Council of Australia report. These include:

Prices:

- **Pool prices** in 2020 under an ETS rise by $43/MWh, or 85% above the status quo.
- **Carbon prices** in 2020 reach $57/t CO2-e, being the levels that the model required to achieve the targeted level of emissions abatement (7% below 2000 levels).

Change in generation mix:

- **The change in generation mix** required under the ETS scenario is predicted to be:
  - o Existing gas generation increases by 9-10 TWh
  - o New gas generation grows to 47 TWh
  - o New renewable generation grows to 36 TWh
  - o Brown coal generation reduces from 33 TWh to 5-9 TWh
  - o Black coal generation reduces from 140 TWh to 132 TWh
- **CCGT plants** are built at the maximum rate of 600MW/year
- **Wind generation** is built at the maximum rate of 600 MW/year
  - o By 2020, the level of generation from wind approaches the long-term resource limit of 7,500 MW assumed by CRA.

4.5) LOAD ASSUMPTIONS

A great many assumptions are made to conduct modelling studies, and there is large uncertainty over many of them. Differences in input assumptions can create large differences between the results of various studies. While it would be outside the scope of this review to extensively compare the input assumptions of the various reports available, ROAM believes one of the most important input assumptions is that regarding the load (demand). ROAM's modelling has indicated that small changes in demand can produce widely different outcomes, and this impact is often underestimated and overlooked. This section reviews and compares the demand assumptions used in the significant reports outlined above.

Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Markets. *Report to Federal Treasury by McLennan Magasanik Associates (MMA). 27th October 2008.*

For this study, the MMRF model supplied an energy demand forecast by industry classification and State for each individual scenario. Annual demand shapes were then derived to be consistent with the relative growth in summer and winter peak demand implied in the NEMMCO, Western Australian Independent Market Operator (IMO) and NT Utilities Commission's forecasts of electricity demand. The growing trend in "peakiness" of demand forecast in the short-term was extrapolated to 2025, with the average to peak demand ratio sustained at the 2025 value for the remainder of the projection period. The proportion of the load that is on the major grids was determined from Annual Reports and NEMMCO data.

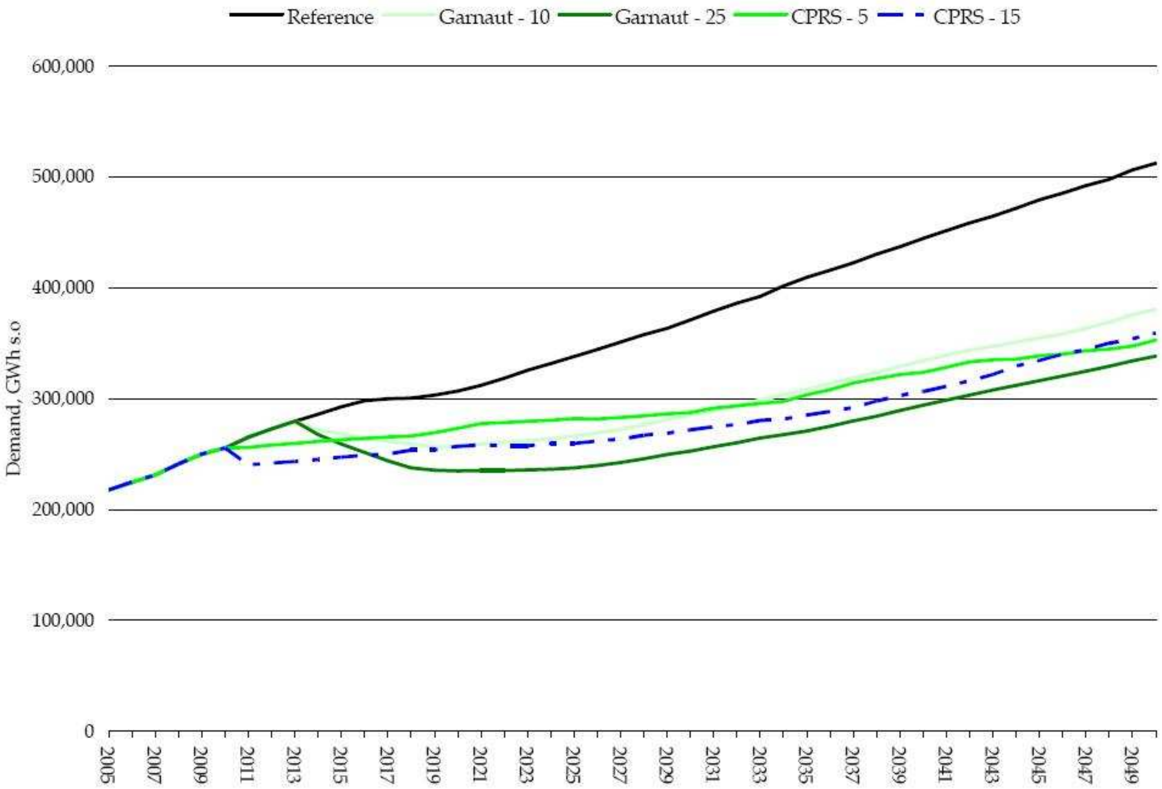
The component of residential demand that was attributed to electric cars was disaggregated from the national demand and modelled as an off-peak load. This then effectively captured the increase in demand due to increased uptake of hybrid cars in an emissions trading world.

The modelling process also involved iterations between the models to ensure feedbacks were modelled in detail. The MMRF model was used to determine electricity demand impacts from the higher electricity prices and higher resource costs determined from the electricity market model simulations. MMRF showed a sudden drop in demand with the onset of emission trading. MMA smoothed this drop over a 5 year period in its simulations.

Figure 4.1 shows the resulting demand projections used by MMA for the bottom-up modelling of the electricity market. Even with five year smoothing, demand falls dramatically in all cases except the reference case, and the 5% reduction case. ROAM's modelling indicates that a demand reduction of this amount, within this timeframe, is unrealistic, and would result in a dramatic fall in the wholesale pool price.

ROAM's view is that while the CPRS may produce a demand response, it is likely to simply slow demand growth, rather than actually produce a reduction in demand. In addition, the slowing in growth is likely to occur gradually, and only with significant assistance from complimentary schemes to address market failures, and barriers to energy efficiency. The sudden introduction of energy efficiency measures in response to increased pool prices is highly unlikely.

Figure 4.1 – MMA demand results: Electricity generation, GWh sent out basis



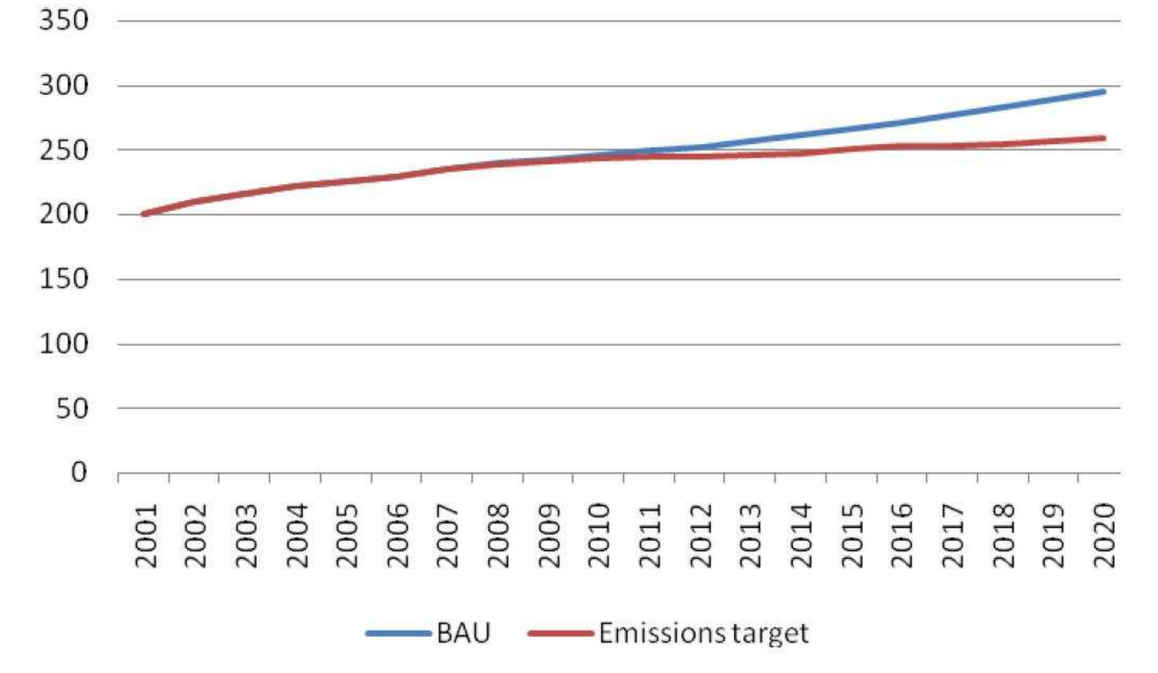
The impact of an ETS on the energy supply industry. *Modelling of the impacts of an emissions trading scheme on the NEM and SWIS. Report by ACIL Tasman to the Energy Supply Association of Australia (ESAA), June 2008.*

The business as usual case (BAU) in this project is based on the 2007 NEMMCO SOO projection of demand in the NEM and the ERA projection of demand in the SWIS without the effects of a 20% by 2020 RET or an ETS. These demand projections include the effects of some existing government sponsored demand reduction and conservation schemes but not the effects of the two policy instruments (the 20% RET and ETS) which are under consideration in this study.

ACIL Tasman's in house general equilibrium model of the Australian economy, Tasman Global, was used to estimate the demand side response to an increase in electricity prices resulting from a cut in electricity sector emissions of 10% and 20% below 2000 levels. For this project, the Tasman Global modelling estimated a 12% reduction in demand by 2020 in the 10% emissions target case and a 14% reduction in demand in the 20% emissions reduction case compared to what would otherwise have been the case (i.e., a BAU case).

ACIL Tasman's electricity demand projectsions for the BAU and 10% reduction cases is shown below in Figure 4.2. ACIL Tasman's results show a more moderate response to the CPRS (than the MMA modelling), which ROAM considers reasonable.

Figure 4.2 – ACIL Tasman demand results: Change in electricity demand, BAU and 10% case, TWh



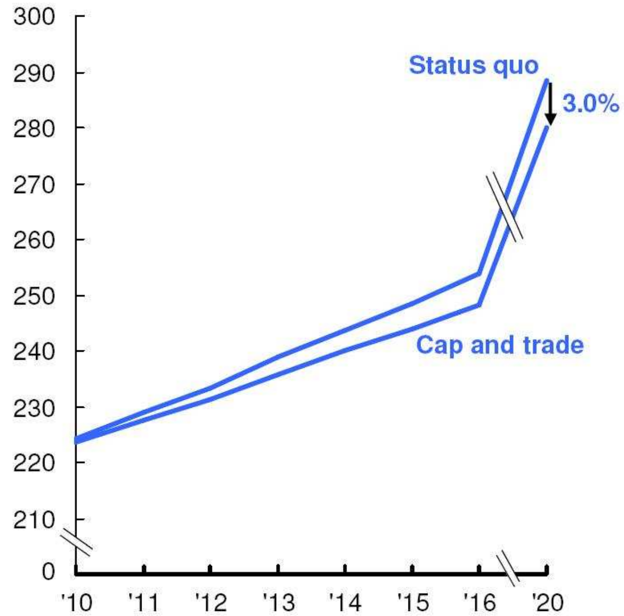
Data source: Tasman Global model results

Market Modelling to Assess Generator Revenue Impact of Alternative GHG Policies. *Report by CRA International to the National Generators Forum, June 2008.*

Demand growth under the business as usual case was assumed to be 2.5% per annum. This is higher than the ACIL Tasman study, which assumes 2.0% growth per annum.

This report has a significantly lower assumption for demand reduction than the ACIL Tasman report. CRA assumes the level of demand reduction to be ~3% of demand by 2020, based on an estimate of the elasticity of demand of 0.2. The demand projections used in the CRA study are shown in Figure 4.3.

Figure 4.3 – CRA demand results: Impact of demand side abatement in electricity sector modelling, TWh sent out



Box 2 – Demand assumptions

Modelling results are highly sensitive to the demand projection assumed as input. In addition, demand projections have high uncertainty, and vary widely between studies. CRA's study shows very little demand reduction in response to the CPRS, whereas MMA's study forecasts a very large reduction in demand. ROAM considers this the most significant difference between studies.

ROAM's modelling suggests that MMA's assumed level of demand reduction in response to the CPRS is highly unlikely. This is a fundamental assumption that significantly affects all results of the study.

4.6) *IMPACTS ON PEAKING GENERATION*

A significant difference in findings between the reports detailed above is in the profitability of gas-fired generation. The MMA report to Treasury finds:

> *Gas-fired generation does not make a major contribution to the abatement task in scenarios with either a RET scheme or deep cuts early on. In other scenarios, a switch to gas fired generation is an important source of abatement in the period to 2030. But in all scenarios gas-fired generation is not a major contributor to abatement in the period after 2030.*

This is contrary to the popularly held opinion that gas-fired generation (as a less emissions intensive form of generation than coal-fired) will benefit from the CPRS with increased volumes and profits (which is the view of the ACIL Tasman and CRA reports).

MMA state five reasons for the small role played by gas-fired generation:

- *The fall in energy demand reduces the need for peaking plant, which are typically gas-fired.*
- *The high cost of gas in the long term makes gas-fired generation an expensive option relative to other abatement options.*
- *The inclusion of fugitive emissions on fuel reduces the abatement differential between gas-fired generation and other forms of fossil fuel generation.*
- *Additional gas-fired generation is encouraged in the reference case under the NSW Greenhouse Gas Abatement Scheme and the Queensland Gas Electricity Scheme, which are assumed to proceed as legislated in the reference case.*
- *The cost of CCS with gas-fired generation is higher than for coal-fired generation.*

The significant reduction in demand modelled by MMA under the CPRS will also be a contributing factor in reducing the role of peaking plant.

ROAM's modelling supports the MMA finding that gas-fired generation is likely to play a less significant role than typically assumed, with fuel switching occurring more between coal-fired stations of varying emissions intensity. The role of gas plant depends heavily on the input assumptions, however, and should be considered to be a highly uncertain factor.

Box 3 – Gas-fired generation under the CPRS

MMA's study challenges the common belief that gas-fired generation will increase significantly under the CPRS, due to fuel switching from coal-fired generation. MMA's results instead suggest that gas-fired generation may increase under some scenarios, but may decrease in others. This is partly due to the reduced demand projections assumed by MMA and the assumed high gas cost projections.

ROAM's modelling supports MMA's finding. Depending upon demand projection assumptions, the level of the emissions permit price, the level of the gas price and the contribution of renewable generation, gas-fired generation may play a large or small role in Australia's electricity future.

4.7) PASS THROUGH OF EMISSIONS PERMIT COSTS IN THE ELECTRICITY MARKET

The MMA report states:

> *Under the CPRS, Victorian brown coal generators set the price in many periods (instead of being base load plant and, hence, price takers as occurs without emissions trading).*

ROAM's modelling also suggests that brown coal generators are likely to become the marginal generators, and hence set the price in Victoria. However, ROAM considers the following statement by MMA to be controversial:

> *Because [Victorian brown coal] generators set the price in the NEM and because they have high emission intensities (of greater than 1 t/MWh), electricity prices increase by the full amount of the increase in their short run marginal costs. [Therefore] wholesale prices increase by more than the value of the permit price in the NEM, particularly in the period before 2020.*

ROAM's modelling suggests that the pass through of the emissions permit price in the electricity market is heavily dependant upon a number of factors. Based upon ROAM's modelling, between 80% and 120% of the emission permit price (in $/tCO2) is likely to appear as an increase in wholesale electricity prices (in $/MWh), depending upon the region and upon generator's abilities to bid strategically and inflate pool prices.

Three main criteria have been identified by ROAM to have a significant impact on the price increase forecast under a CPRS:

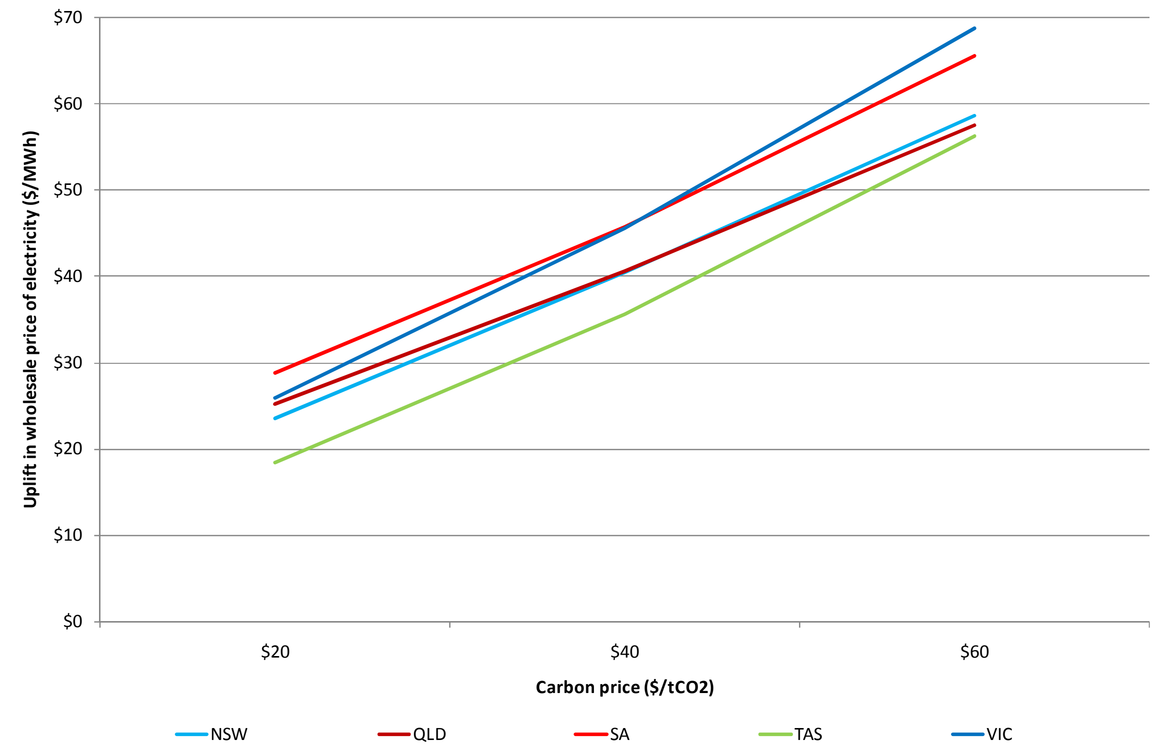
1. The region of the NEM
2. The carbon price
3. The ability of generators to bid strategically

These are addressed separately below.

Significance of the region

ROAM's modelling consistently shows that the amount of uplift in the wholesale electricity price due to the CPRS is dependent upon the region, as illustrated in the figure below.

Figure 4.4 – Increase in price of electricity (Low load growth)



Victoria, with its high proportion of electricity produced from emissions intensive brown coal, shows a relatively larger uplift. Tasmania however shows a lower uplift in the price, largely due to the high proportion of energy sourced from emissions free hydro generation in the region.

The price uplift in Tasmania has nonetheless been found to be substantial, which is not reflected in the National Greenhouse Accounts factors workbook. The Department of Climate Change NGA factors correctly indicate that electricity in Tasmania is only responsible for a fraction of the indirect emissions of electricity in other states (the EF for scope 2 emissions is only 0.12 kg CO_2-e/kWh, compared with factors of between 0.84 kg CO_2-e/kWh and 1.22 kg CO_2-e/kWh for other regions of the NEM)[7]. However, the price of electricity in Tasmania is closely correlated with the price in Victoria, due to normal market behaviour[8]. Therefore, despite being responsible for low emissions compared to the rest of the NEM, Tasmania electricity users will see a substantial and disproportionate price increase.

Significance of the emissions permit price

The level of the carbon price itself dictates how much of the increase in cost is passed on to consumers. This is because the changes in generator merit order (for example,

[7] Department of Climate Change, National Greenhouse Accounts (NGA) Factors, January 2008.

[8] Prices in the NEM are set by one region only, modified by the Inter-Regional Loss Factors, except in the event of transmission congestion which causes price separation between regions.

changing the order of dispatch of coal and gas generation) occur at different prices in different regions, depending upon the properties of the generators and fuels in those regions. At lower carbon prices, lower cost abatement opportunities can be utilised.

Generator strategic bidding

ROAM's results shown in Figure 4.4 assume that generators are able to exercise the same amount of market power that they currently do, in the absence of a carbon price. With the introduction of higher levels of carbon price, it is expected that coal-fired generators will have less ability to bid strategically, and will be forced to bid closer to their short run marginal costs. If generators bid according to their costs, the amount of the emissions permit price that appears as an increase in the pool price is much lower (between 80% to 100%, depending upon the region) [9].

Box 4 – Pass through of the emissions permit cost in the electricity market
MMA's study finds that the emissions permit cost will be entirely passed through into the wholesale pool price. ROAM's modelling suggests that the proportion of the emissions permit price that will appear as an uplift in the pool price will vary from 80% to 120% depending most critically upon: 1. The region 2. The emissions permit price 3. The ability of generators to exercise market power in strategic bidding

4.8) OTHER REPORTS

A variety of other reports discuss the impacts of the CPRS and RET schemes on the Australian electricity market, but are considered less significant for review than those listed above. This may be because they provide less detailed analysis, or because they have been superceded by later, more sophisticated studies.

For reference purposes, other reports that analyse the impacts of the CPRS (perhaps in combination with the RET) on the electricity market in Australia include:

- ***Climate change policies: international and Australian trends and impacts on the National Electricity Market.*** Report prepared for the National Electricity Market Management Company (NEMMCO)by the *National Institute of Economic and Industry Research (NIEIR)*, June 2008.
    - This report provides broad-strokes analysis, without the detail of those described above and is therefore not considered in great detail here.
- ***Impacts of a National Emissions Trading Scheme on Australia's Electricity Markets.*** Report to National Emissions Trading Taskforce by *McLennan Magasanik Associates (MMA)*, 26 July 2006.

[9] The pass through of carbon price to wholesale electricity price is approximately 1:1across the NEM as a whole, as a consequence of the NEM average emissions factor being approximately 1tonne of CO2/MWh of generation sent out. $20/tonne of CO2 translates to approximately $20/MWh wholesale price increase. Detailed modelling provides a more precise estimate by time of day, region and over extended time periods as the plant and technology mix shifts from coal towards gas and from high towards lower emission technologies.

  - This report has been superceded by MMA's more recent, and far more sophisticated report to Treasury.
- ***Explanation of results on electricity market impacts of emissions trading.*** *McLennan Magasanik Associates (MMA)*, 30 November 2006.
  - This brief note clarifies and explains in more detail some of the results from MMA's previous electricity market modelling study.
- ***Analysis of Greenhouse gas policies for the Australian Electricity Sector.*** A report for the National Generators Forum by *CRA International*, September 2006.
  - This report has been superceded by CRA's more recent and more sophisticated study for the NGF.
- ***The Economic Impacts of a National Emissions Trading Scheme.*** Report to the National Emissions Trading Taskforce by *The Allen Consulting Group*.
  - This is a broader analysis of economic impacts, not focused on the electricity market in detail.

The following reports provide some insights into the implications of the RET, in the absence of the CRPS. These have not been discussed in this report in detail, since the RET is modelled fully in conjunction with the CPRS in the latest detailed studies.

- ***Implications of a 20 per cent renewable energy target for electricity generation.*** Prepared for APPEA by *CRA International*, November 2007.
  - This study analyses the cost of implementing a 20% by 2020 RET in conjunction with the CPRS (from 2010). The modelling shows that the combination of an ETS with the 20% RET is significantly less efficient than the CPRS alone in achieving emissions abatement.
- ***Wind Energy in South Australia.*** Planning Council Wind Report to ESCOSA, by *ESIPC*, April 2005
  - This report provides advice on any impacts that proposed wind-farm developments might have on the long term interests of South Australian consumers with respect to the price, quality and reliability of electricity services.
  - The issue of wind development in South Australia is examined from two different perspectives:
    - a detailed, South Australian specific analysis was conducted using local data, actual projects and real market conditions; and
    - a review of international experience with wind generation and the potential impacts of increasing levels of wind.
- ***Review of Impacts of High Wind Penetration in Electricity Networks.*** Report by C. Buckley, N. Scott, H. Snodin, and P. Gardner for ESIPC, 20 March 2005.
  - This report provides a review of specific overseas markets where wind energy has been implemented in significant quantities. Issues have been highlighted that may have some relevance to the South Australian market.
- ***Wind energy and the National Electricity Market with particular reference to South Australia.*** A report for the Australian Greenhouse Office prepared by *Hugh Outhred*, January 2003.
  - This report outlines the key issues that may arise in South Australia with extensive development of wind power. Recommendations requiring

governments to take a more active role in the wind energy industry are proposed.

The following reports provide insight into the potential renewable resources available in Australia, the costs of implementing renewable technologies, and the limitations and barriers to their implementation.

- ***Lighting the way – Toward a sustainable energy future***, *InterAcademy Council*, October 2007.
    - o Among other topics, this report compares the costs of implementing various low emissions energy alternatives, and technical issues associated with their wide scale implementation.
- ***Techno-economic assessment of power generation options for Australia.*** Technology assessment report 52, *Cooperative Research Centre for Coal in Sustainable Development*. L. Wibberley, A. Cottrell, D. Palfreyman, P. Scaife and P. Brown. April 2006.
    - o This report summarises technology assessments of low emission electricity generation technologies in an Australian context, with a time horizon of 2015. Fossil fuel plants with carbon capture of various types are assessed in detail, along with nuclear, solar thermal technologies, biomass and wind.
- ***Powering the Nation.*** A review of the costs of generating electricity, *PB Power,* May 2006.
    - o This report examines the costs of generating electricity in the UK. Technologies assessed include:
        - ▪ Coal (pulverised fuel, circulating fluidised bed combustion plant and integrated gasification combined cycle)
        - ▪ Gas (open cycle and combined cycle)
        - ▪ Nuclear
        - ▪ Wind (onshore and offshore)
        - ▪ Biomass
        - ▪ Tidal
        - ▪ Wave

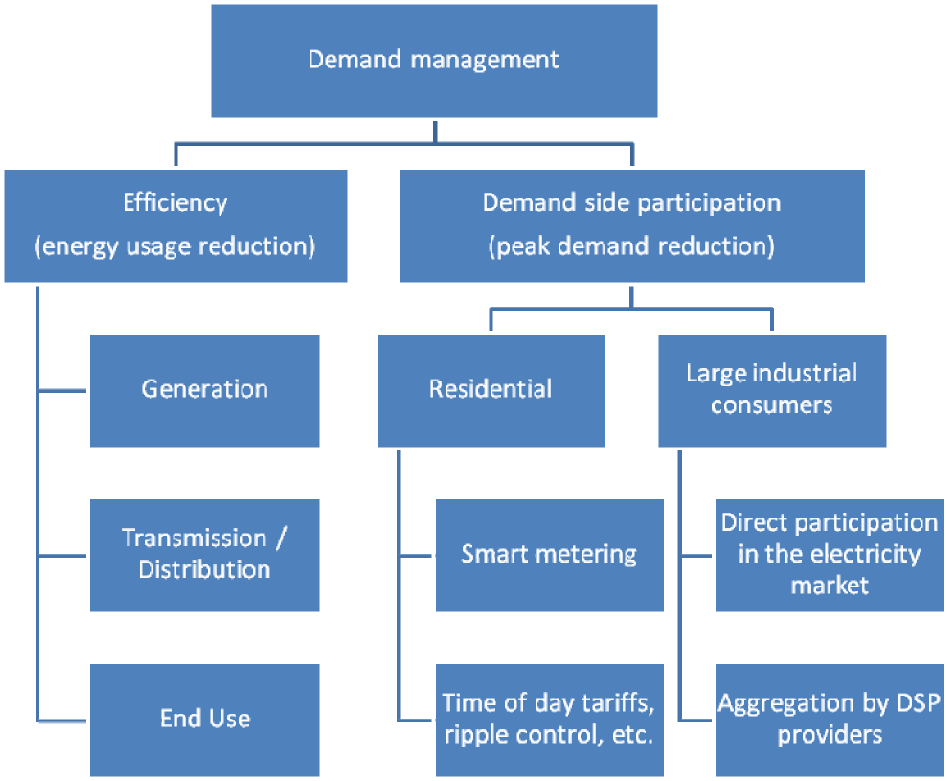
5) DEMAND SIDE MANAGEMENT

It is expected that rising energy prices under the CPRS will drive increasing energy efficiency on the supply and demand sides. Investment of CPRS revenues in energy efficiency measures is also stated as a government priority. Increasing energy efficiency may drive energy and demand forecasts below those so far predicted by NIEIR for NEMMCO, which will have significant effects on investment decisions, and the running of existing plants.

As a part of energy efficiency measures, there is a renewed interest in demand side participation as a method for reducing peak demand. This will also have significant implications for investment decisions and the daily running of the market.

Demand side management may therefore include the aspects illustrated in the Figure below.

Figure 5.1 – Aspects of Demand Management



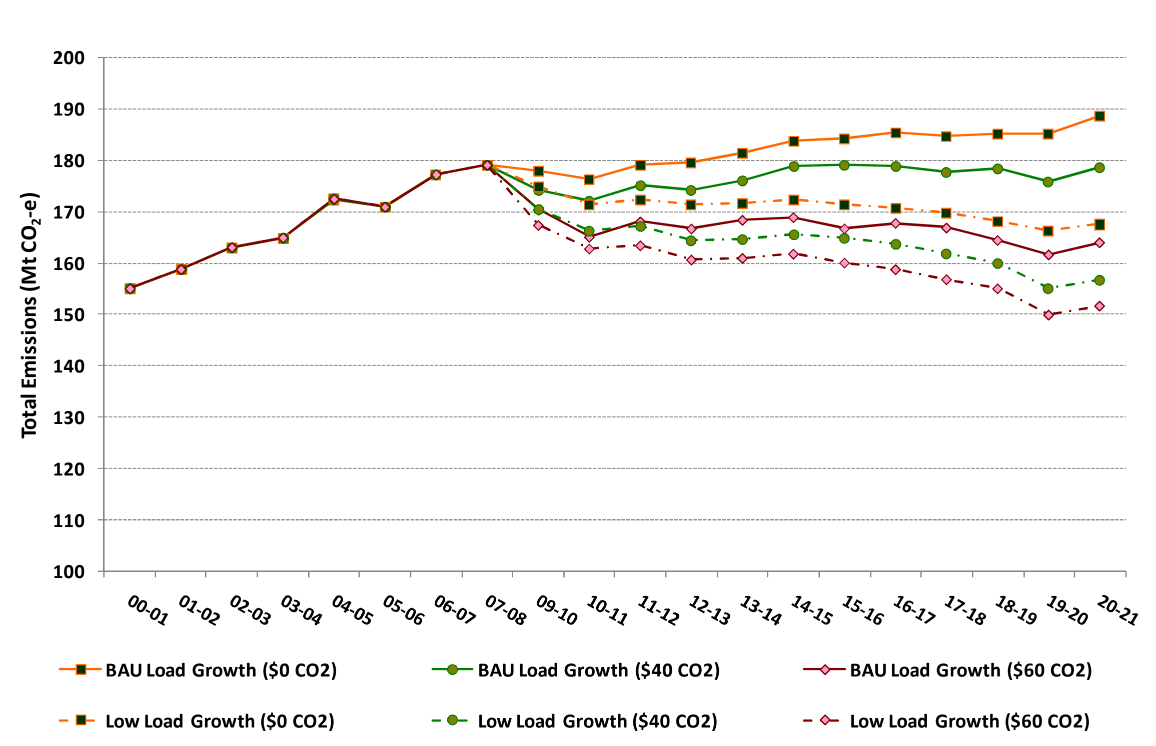
5.1) ENERGY EFFICIENCY FOR EMISSIONS MITIGATION

To illustrate the emissions mitigation potential of energy efficiency, ROAM has modelled the total emissions from the National Electricity Market (NEM) under a variety of carbon prices, and with two alternative demand growth scenarios:

1. Business as usual (BAU) demand growth (as defined by the NEMMCO medium growth forecasts)
2. Low demand growth (as defined by the NEMMCO low growth forecasts).

All other assumptions were the same. The resulting total emissions from the NEM under these different levels of load growth are illustrated in the figure below.

Figure 5.2 – Total emissions from the NEM



At any particular carbon price, reducing the load growth substantially reduces the emissions from stationary energy. The sensitivity of modelling outcomes to the demand profile was emphasised in the previous section.

NIEIR's forecasting of the price elasticity of demand for electricity in NEM Regions indicates that if price increases by 1% from current levels, demand decreases by 0.35%.[10] As the price elasticity of the demand is less than 1, it is usually considered to be relatively inelastic. In addition, it is widely recognised that there are substantial non-economic barriers to energy efficiency measures. Therefore, for effective operation of the CPRS non-economic barriers to energy efficiency must be identified and addressed, and other incentive schemes implemented to realise the potential 'low hanging fruit' available in this area.

6) DISTRIBUTION AND TYPE OF RENEWABLE TECHNOLOGIES STIMULATED BY THE RET AND CPRS

The distribution and type of renewable technologies stimulated under the CPRS will be a critical factor in determining the impacts of the two schemes. Large quantities of wind energy (sufficient to meet the 45,000GWh target of the expanded RET) are in various stages of approval, much of this located in South Australia. The weak transmission grid in

[10] NIEIR, 'The own price elasticity of demand for electricity in NEM regions', available at http://www.nemmco.com.au/about/419-0026.pdf

this state will have very significant additional demands placed upon it if all projects go ahead. Alternatively, WorleyParsons has recently proposed the construction of 8,400MW of solar thermal energy by 2020, which could fill a large proportion of the RET. Since this is likely to be located in other areas, and will have far less intermittency, the outcomes for the market will be significantly less.

Technologies available to meet the 2020 RET

The technologies considered available to meet the expanded 2020 RET are:

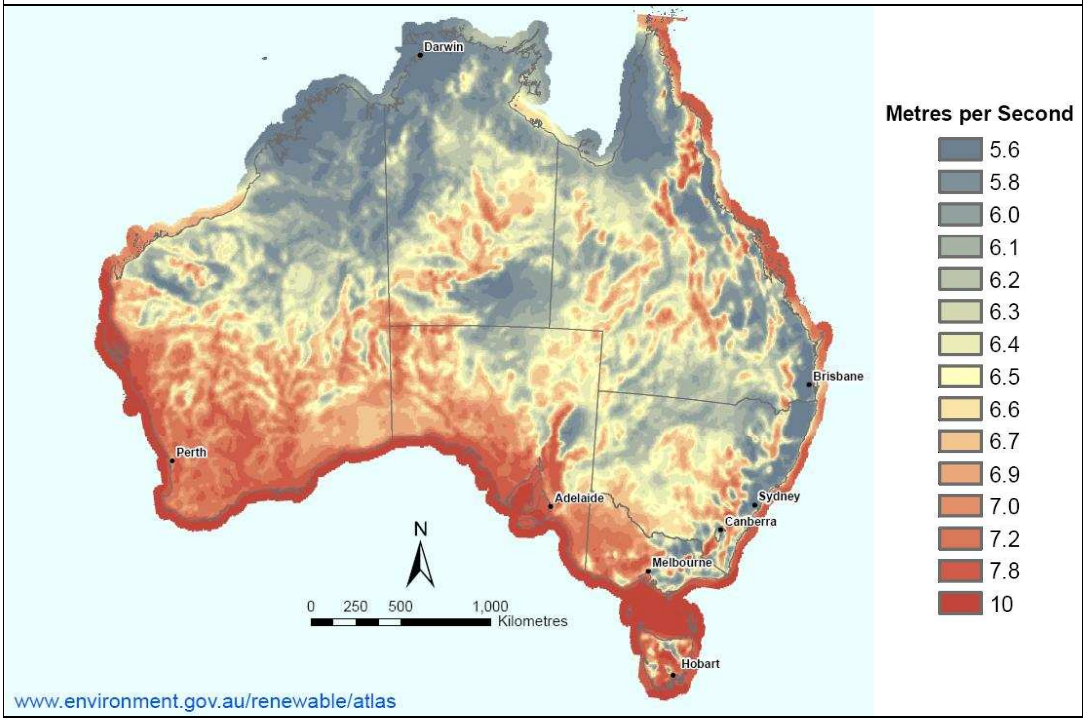
- Wind
- Sugar cane bagasse
- Solar technologies
    - Solar PV (flat panel)
    - Solar concentrator PV
    - Solar thermal towers
    - Solar hot water
- Geothermal

These are discussed in the sections below, with anticipated contributions for each.

6.1) WIND

Figure 6.1 shows a map of the mean wind speeds in Australia at a typical turbine hub height.

Figure 6.1 – Mean wind speed at 80m above ground level[11]



Tasmania, Victoria, South Australia and Western Australia have excellent wind resources. The limitations on development of wind energy in these states is likely to be related to other factors.

It is typically considered feasible to install wind to the level of 20% of the peak demand of a region. Wind generation beyond this level is considered more challenging and expensive to introduce (with factors such as system reliability and voltage control becoming more problematic). In MMA's study for the Treasury, wind development was limited to 25% of the peak demand in any state (unless accompanied by a transmission upgrade, which is automatically selected by the model if it is economical), consistent with this prevailing view.

ROAM has sophisticated transmission modelling capabilities that allow a more investigative approach to wind installation. ROAM regularly runs wind modelling studies with wind in some states (notably South Australia) of up to 50% of a regions peak demand. Since transmission limitations and system reliability are modelled explicitely, ROAM is able to make an independent judgement about the level of economic wind investment in a region.

To support further development of wind generation in South Australia (beyond 50% of peak demand) it may be feasible to construct a DC transmission link from South Australia to Queensland (which has limited wind resources, and a rapidly growing load), with the potential for future integration with geothermal resources in the north of South Australia.

[11] Australian Government, Department of the Environment, Water, Heritage and the Arts, Renewable Energy Atlas of Australia, 2008. www.environment.gov.au/renewable/atlas

This additional export capacity utilising the lowest cost form of renewable energy may be an economical way of expanding renewable generation in Australia beyond the 20% wind limit of each region.

In addition to limitations involving the demand in a region, ROAM has identified several non-resource related factors limiting development in wind generation in Australia, as detailed below.

6.1.1) Factors limiting development in wind

Transmission congestion

There is evidence that transmission congestion is already limiting the construction of wind farms in some parts of Australia. For example, Shea Oak Flat wind farm, located in the ADE ANTS zone in South Australia has been approved, but is suspended until transmission constraints on the Yorke Peninsula are addressed (as of April 2008). Similarly, Wattle Point II (also in SA) is reportedly suspended indefinitely due to transmission constraints.

ROAM's modelling shows that wind farms located in South Australia may suffer very serious curtailment due to transmission congestion if they are all built. Very few of these wind farms can be installed before curtailment reaches ~10% of their annual energy (and greater). Curtailment at these levels will create a strong incentive for wind farms to locate elsewhere.

Although thermal generators are arguably likely to be more strongly affected by transmission congestion than wind generators, ROAM believes that for a realistic outcome, transmission congestion should be considered a serious factor prohibiting construction of wind in the NEM.

Lack of incentives

Many wind farms are in various stages of development, but have reportedly been suspended indefinitely without explanation. This is likely due to a lack of incentives. There has been sufficient renewable generation in the NEM to exceed the existing MRET, which provides little incentive for new construction. The uncertain future of the MRET scheme also slowed investment. It is anticipated that many of these suspended projects will proceed under the expanded RET. Indeed, in October 2000 Tasmanian based company Roaring 40s reinstated two projects 7, at Musselroe (TAS) and Waterloo (SA), which had been previously cancelled due to lack of regulatory support.

Market Limitations

Tasmania has excellent wind resources, but has limited wind penetration due to the lack of a competitive market in Tasmania. With only one retailer and one generator (who can be assumed to be fully contracted) it is extremely difficult for external players to enter the market. To reduce this problem, it may be feasible to build a new complementary DC transmission link from TAS to VIC solely to support substantial wind development in Tasmania.

Box 5 – Anticipated development in wind generation
As the lowest cost form of renewable generation, ROAM expects that the majority of the RET will be met by wind generation. SA, VIC, WA and TAS have excellent wind resources, where the main limitation is likely to be the peak demand in South Australia (evidence suggests that up to 20% of the peak demand in each region may be met without significant problems due to voltage stability and intermittency) and frequency control in Tasmaina. Fulfilment of the MRET has also limited development in wind generation to date, but suspended projects are expected to be renewed with the onset of the expanded RET.

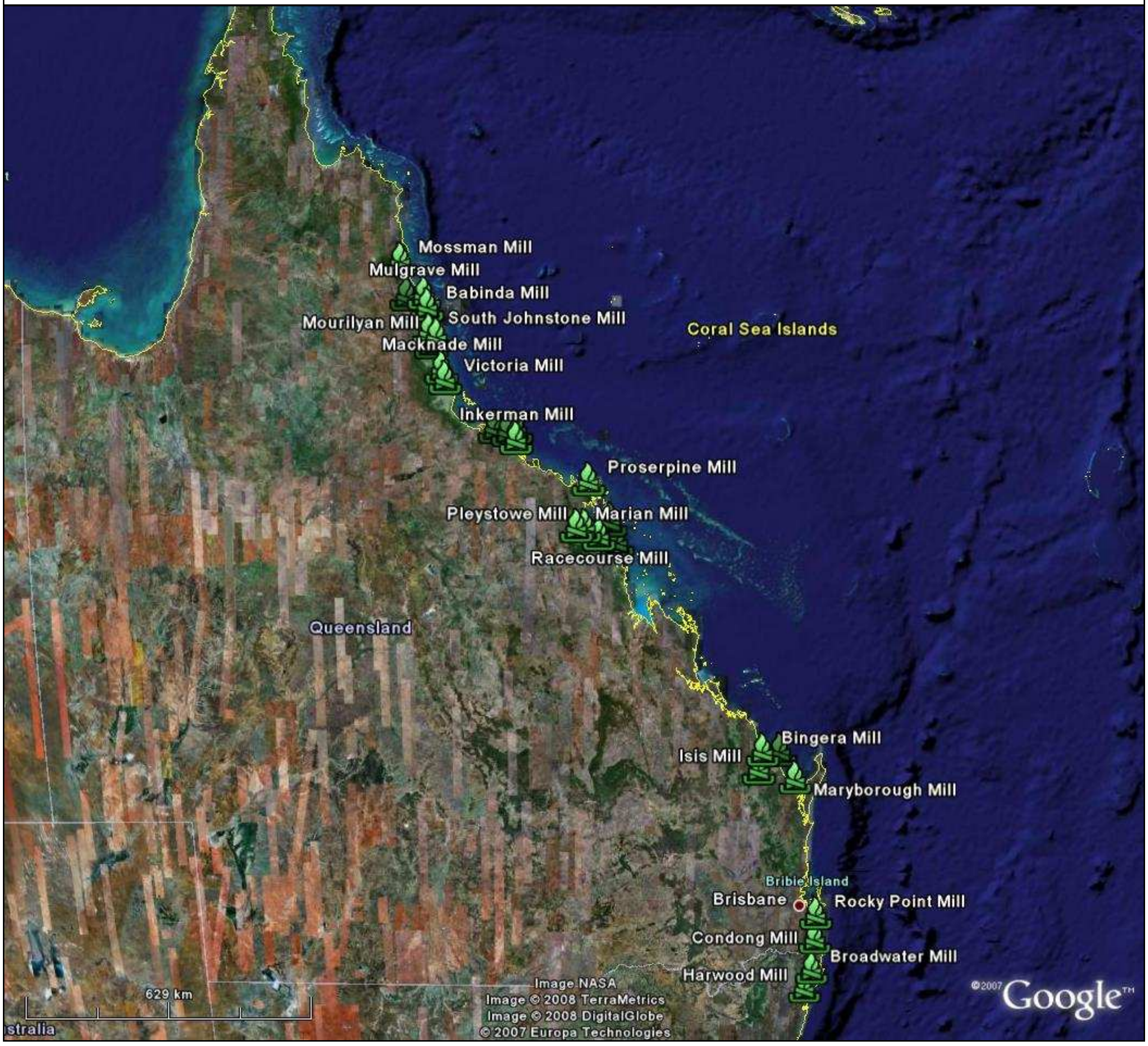
6.2) SUGAR CANE BAGASSE

The majority of Australia's sugar mills are located in Queensland. When sugar cane is crushed and the sugar removed, a fibrous material called bagasse remains. This can be burnt in boilers to generate electricity. Although the burning of bagasse releases CO_2 into the atmosphere, this CO_2 is re-absorbed by the next season's sugar cane crop and hence the process is carbon neutral.

Bagasse represents a significant renewable energy source for Queensland; 33 million tonnes of sugar cane were crushed by Queensland mills in 2006. Since 1.5 million tonnes of cane is sufficient to supply a 30MW bagasse unit for one year, this suggests that as much as 660 MW of bagasse generation is possible in QLD.

The locations of Queensland's sugar mills are shown in Figure 6.2. Most use bagasse to generate sufficient electricity for their own needs, but do not contribute significant amounts of electricity to the NEM. The majority of the bagasse is burnt inefficiently, or disposed of.

Figure 6.2 – Queensland sugar mills



The generation capacities of these mills are largely used to power the operations at the mill, and only a small percentage is supplied to the NEM (if any). However, several mills have installed generation capacities beyond their own needs with the aim of significant electricity exports. These are shown in Table 6.1. Of these, the Pioneer mill is the most recent upgrade, with cogeneration facilities commissioned in 2006.

Table 6.1 – Queensland mills that export significant generation to the NEM

Mill name	Region	Capacity[12]	MWh pa	Capacity factor	Company
Pioneer	Herbert-Burdekin	67.78 MW	200,000	34%	CSR
Invicta	Herbert-Burdekin	38.8 MW	150,000	44%	CSR

[12] As listed in the NEMMCO SOO 2007.

Table 6.1 – Queensland mills that export significant generation to the NEM					
Mill name	**Region**	**Capacity[12]**	**MWh pa**	**Capacity factor**	**Company**
Rocky Point	Southern	28 MW	140,000	57%	W H Heck & Sons
ISIS	Southern	25 MW	-	-	AGL Energy Services

6.2.1) Factors limiting development of biomass/bagasse

Hidden costs

For bagasse to be burnt efficiently at mills, significant upgrades to their boiler technology must occur. This is expensive; Pioneer mill recently installed 63 MW of capacity as cogeneration, making the mill capable of supply 200,000 MWh of electricity per annum. This was initially estimated to cost $100 million, but has ended up costing between $150 million and $170 million, leaving the project far over budget. The expense blow-out of this project has been said to have detered further potential investors.

Small number of potential investors

Unlike wind farm development, which is open to any interested party for investment, biomass and bagasse generation facilities are extremely closely linked to the industry providing the waste material for fuel. The sugar industry in Australia is owned by a small number of operators, Electricity generation is not their core business, and they are reputed to be cautious of investing in an area they are relatively unfamiliar with.

Linkages with sugar markets

Another complicating factor is that bagasse generation is closely connected to the sugar industry, meaning that movements in world sugar prices impact upon decisions to invest in bagasse electricity generation. This is a significant complication in moving to high capital cost investments in associated power generation plant.

Fulfilment of the MRET

As for wind developments, further investment in biomass has been limited by the fulfilment of the MRET causing a significant fall in the price of renewable energy certificates (RECs). This means that further investors in biomass generation would not be able to meet their long run marginal costs.

With the expansion of the RET to 20% by 2020 there may be an renewed interest in development of biomass/bagasse generation.

Box 6 – Anticipated development in bagasse/biomass generation
Sugar cane bagasse generation has the potential to provide up to 660MW to Queensland, and has the potential to be sufficiently supported by the expanded RET. Investment in bagasse generation has been limited to date due to the small number of businesses in the sugar industry, and their relative lack of experience in the electricity generation sector. Linkages with the sugar market, and blow-outs in capital costs of past projects have also inhibited development. A limited amount of renewed interest is anticipated under the expanded RET.

6.3) SOLAR TECHNOLOGIES

Solar power on a large scale is a feasible possibility for making a significant contribution to the 2020 MRET. Two general types of technology are currently available:

- Solar photovoltaics (PV) (silicon cells), including
  - Traditional flat panel cells
  - Solar concentrator cells (with reflective dishes to concentrate the sunlight)
- Solar thermal
  - Troughs
  - Towers

Traditional flat panel solar photovoltaics

Flat panel solar photovoltaics are a well developed technology. This means that they are relatively easy to obtain and install, but also means that substantial reductions in cost over time are not anticipated (without fundamental changes to the nature of the technology). Many of the existing PV installations are intended only to supplement an external power supply, removing the requirement for storage.

Solar concentrator photovoltaics

Solar photovoltaics can be more cost effective on a large scale if concentrator technologies are used. This involves using heliostats (mirrors that follow the sun through the day) to focus sunlight onto a small but highly efficient photovoltaic cell.

Solar Systems is planning the construction of a 154 MW solar concentrator photovoltaic plant in Mildura/Swan Hill (Victoria). The first stage of the plant is planned for commissioning in 2010, with full service of the plant in 2013.

Solar Thermal

Solar thermal plants are an emerging technology. This means that they are currently relatively expensive, but the capital costs are expected to decrease over time as the technology becomes more developed. There are various types of solar thermal technologies; one of the most promising is solar towers. Solar towers involve an array of mirrors on the ground that reflect light into a focal point on a tower. Water can be heated to steam in the tower and then used to power a boiler.

A 10MW plant is currently undergoing feasibility studies for installation at Cloncurry, and is expected to be commissioned in September 2009. This plant will be scaled up by the construction of an array of towers, each fed by a separate array of mirrors at ground level. 54 towers will each supply a maximum output of 185 kW.

An extremely advantageous feature of solar plants of this type is the ability to store energy for full time production. This avoids the expensive problem of storage associated with both wind and solar photovoltaic technologies.

Solar thermal facilities are considered likely to contribute substantially to meeting the 2020 MRET, particularly in later years when further development in wind is likely to become expensive.

Solar hot water

The second largest single contribution to the existing MRET (after hydro) was from solar water heating. Solar water heating accounted for 20% of RECs validated in every year of the MRET (contributing an average of 670,000 RECs per annum), although it is anticipated that this percentage will reduce as the annual targets increase significantly.

6.3.1) Factors limiting development of solar generation

The main factor limiting development of solar PV technologies is the extremely high cost. Solar PV is far more expensive than other forms of renewable energy.

Solar thermal energy is also currently relatively high cost, although with research funding the costs are expected to fall significantly over the coming decade. Although solar thermal technologies show substantial promise in the longer term, they do require substantial research investment to bring cost reductions.

Box 7 – Anticipated development in solar generation
Solar PV is an extremely expensive form of large scale power generation, and is not expected to contribute substantially to the expanded RET. Concentrating solar PV may show more potential, but is expected to remain significantly higher cost that wind and bagasse generation to 2020. Solar thermal generation shows greater potential, but requires substantial research investment to bring down costs to competitive levels. Very significant emissions permit prices will also be required in addition to the RET for this technology to compete with conventional technologies.

6.3.2) Geothermal Energy

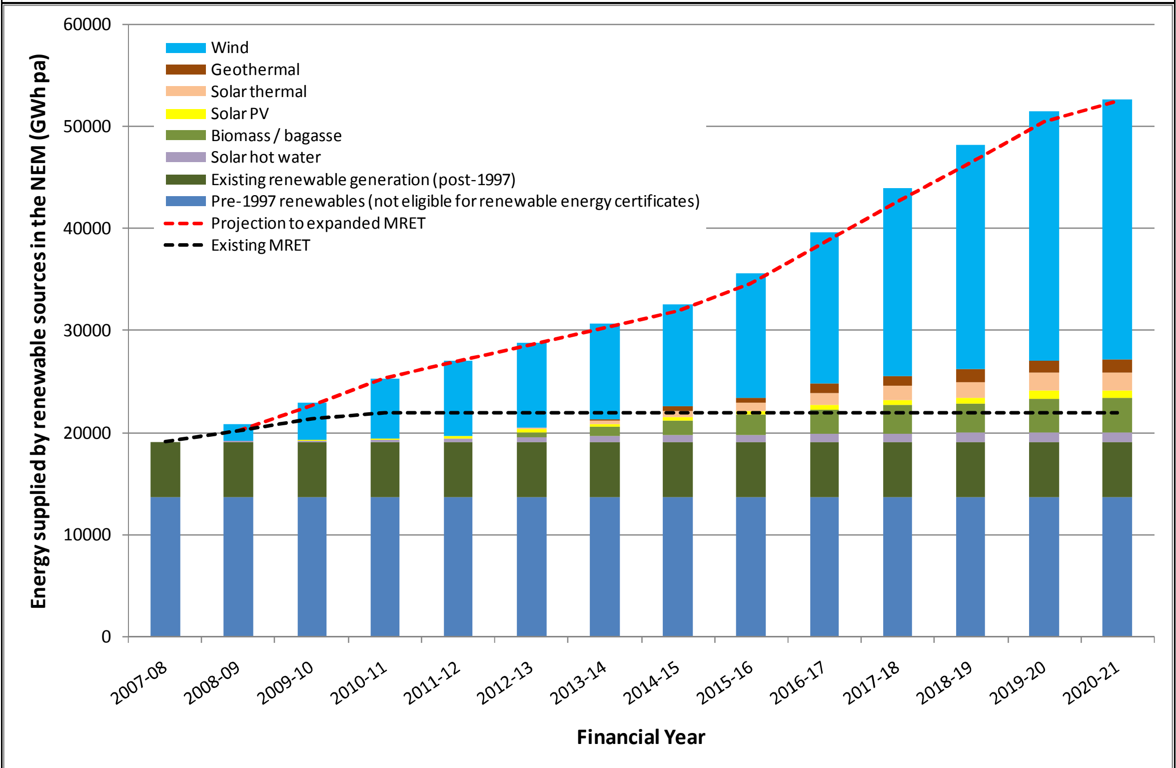
Australia has extensive geothermal resources Unlike international experience with geothermal energy, where steam reaches the earth's surface through fissures associated with volcanic activity, Australia's geothermal resources are available only deep underground requiring extensive drilling to bring the steam to the surface. Whereas the technology for exploiting volcanic geothermal energy is proven, the technology to access deep 'hot rock' energy is currently in the pilot stage and will require significant time to mature before a substantial amount of geothermal energy can be introduced to the NEM cost effectively.

6.4) RENEWABLE ENERGY TARGET MODELLING SUMMARY

ROAM's modelling has contained over 10,000 MW of proposed wind projects, which is sufficient to meet the 45,000 GWh of expanded RET alone. Other significant renewable energy projects proposed include solar thermal and bagasse developments.

ROAM considers the breakdown of renewable technologies shown in the figure below to be likely. A bilinear approach to the 2020 target is assumed, in line with the projections proposed in the COAG Working group discussion paper[13].

Figure 6.3 – Likely contributions to 2020 RET by renewable technologies



Of these new generators, ROAM considers wind to be the largest contributor, followed by bagasse (with the vast majority of generation located in Queensland). The figures below show the new renewable generation from state by 2020, and the increase in wind generation between 2008-2020. Although South Australia is currently the largest producer

[13] COAG Working Group on Climate Change and Water, Design Options for the Expanded National Renewable Energy Target Scheme, June 2008.

of wind, it will be overtaken in volume within a few years by Victoria and New South Wales.

Figure 6.4 Likely contributions to new renewable energy generation in 2020

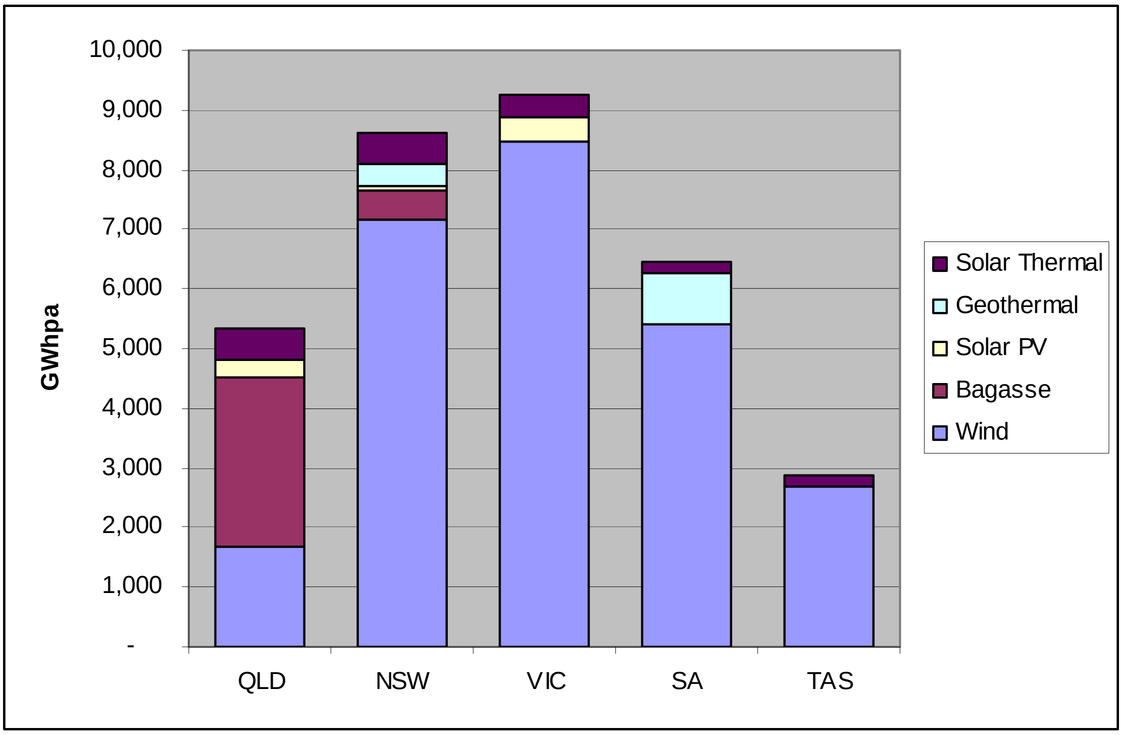
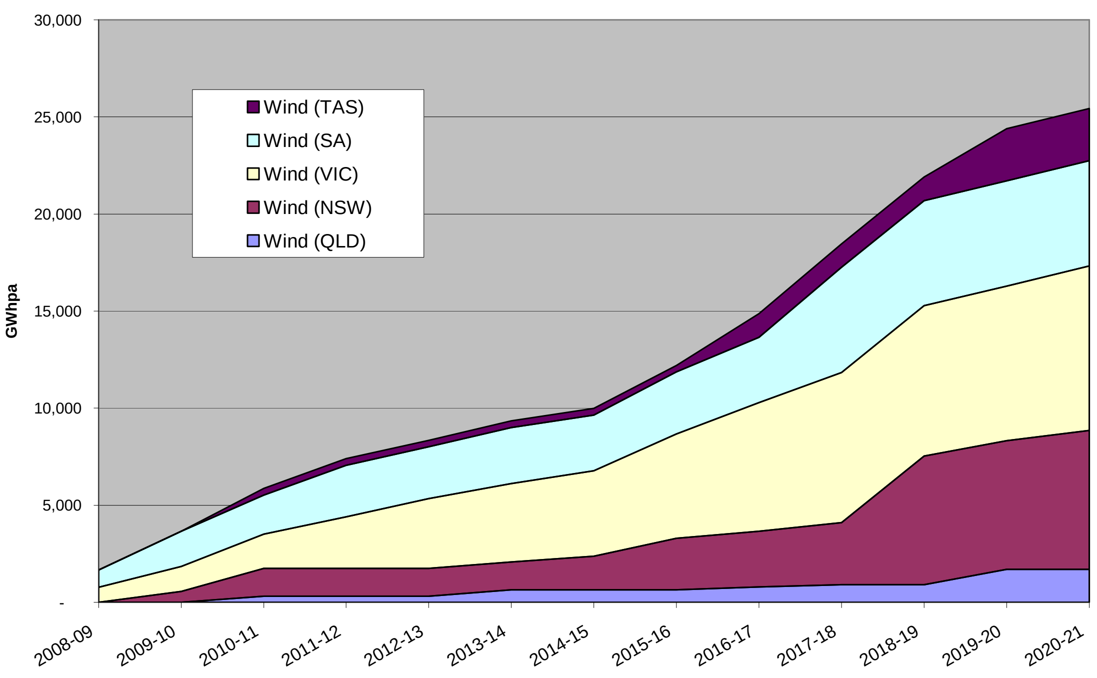


Figure 6.5 Likely locations of wind generation by state under RET



6.5) SELECTION OF RENEWABLE TECHNOLOGIES USED IN OTHER STUDIES

A number of studies have been carried out predicting the role that renewables will play under the CPRS and RET. Individual assumptions in each study about the cost, feasibility and capacity of particularly newer technologies produces varying magnitudes of geothermal, solar and biomass production[14].

As in Section 4) we reviewed results from three modelling studies:

- ACIL Tasman, prepared for the Energy Supply Association of Australia (June 2008), The impact of an ETS on the energy supply industry.
- CRA International, prepared for the National Generators Forum (May 2008), Market modelling to assess generator revenue impact of alternative GHG policies. (as summarised in the report prepared for the Business Council of Australia by Port Jackson Partners Limited (21 August 2008), Bringing specific company economic perspectives to bear on the ETS design..
- Report to Federal Treasury by McLennan Magasanik Associates (MMA) (27th October 2008), Impacts of the carbon pollution reduction scheme on Australia's Eelectricity Markets

[14] Unfortunately, each report presents its results subtly differently (e.g., total renewables vs new (post 2008) renewables, energy production vs capacity, actual or sent out production, etc) making direct comparison of results across studies challenging.

Renewables input assumptions

In MMA's modelling, intermittent renewables such as wind energy were limited to 25% of a region's peak demand, with the exception of South Australia on the condition that the transmission network to Victoria was upgraded. Capacity limitations for each technology were derived from earlier simulations, and other factors such as limited suitability of sites were taken into account.

The BCA report reviewed two studies conducted by ACIL Tasman[15] and CRA[16], modelling the impact of an emissions trading scheme on the electricity market. The introduction of new plant (both type and timing) was optimised to achieve necessary generation at the lowest cost. Constraints such as maximum build rates for new technologies were imposed, however transmission constraints were not included in either model. ROAM's modelling shows transmission congestion is a key factor in the positioning and feasibility of new technologies, particularly for intermittent generation such as wind (see Section 6).

An outline of the predicted sources of 2020 energy generation for each study is shown in the figures below. The three MMA scenarios correspond to:

- 5% cut in 2020 emissions from 2000 levels, with no RET (CPRS only)
- 5% emissions cut including RET
- 15% emissions cut including RET.

The ACIL and CRA scenarios assume a 10% CO_2 abatement from 2000 levels by 2020.

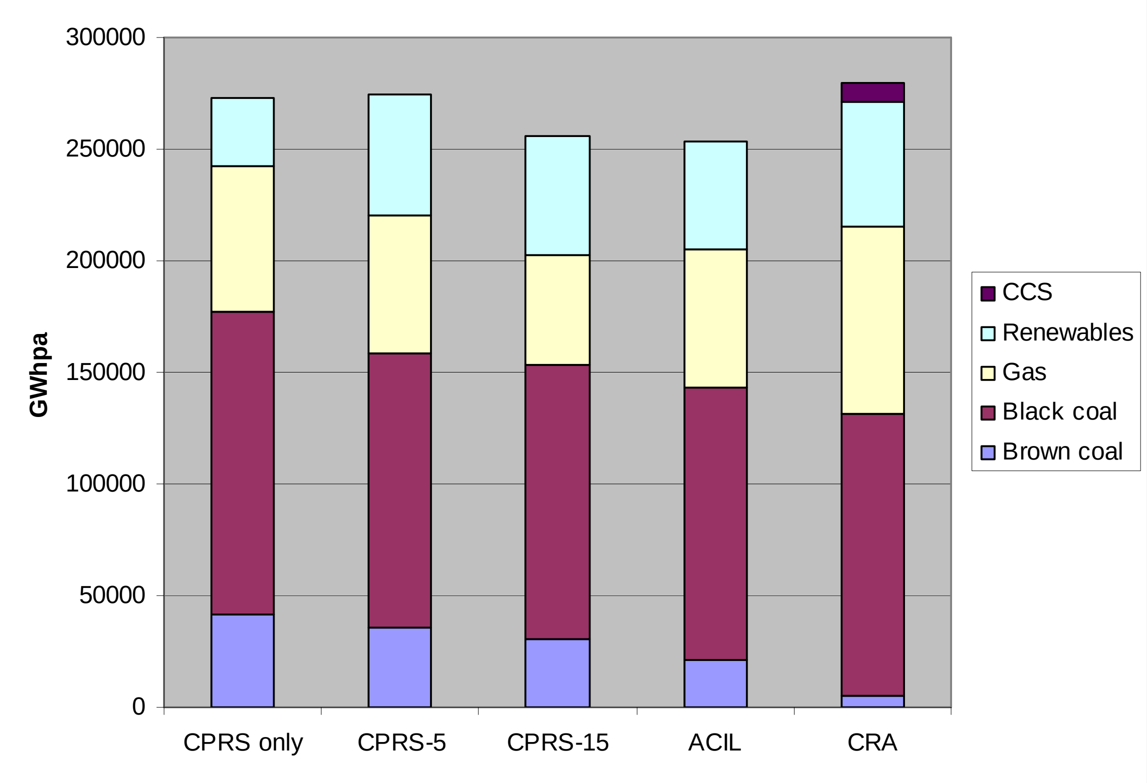
Generation results – all technologies

Figure 6.6 shows the projected breakdown in electricity generation in 2020 from the studies under review. In the MMA modelling, without the RET scheme only 5% of energy will come from renewable sources (11% including existing hydro) compared to 13-14% under the RET (total renewables providing 20% including existing hydro). ROAM's modelling also finds that at the projected emissions permit prices, renewable generation is unlikely to be supported solely by the CPRS.

[15] ACIL Tasman, 'The impact of an ETS on the energy supply industry', July 2008

[16] CRA International, 'Market modelling to assess generator revenue impact of alternative GHG policies', May 2008

Figure 6.6 Predicted sources of electricity generation in 2020



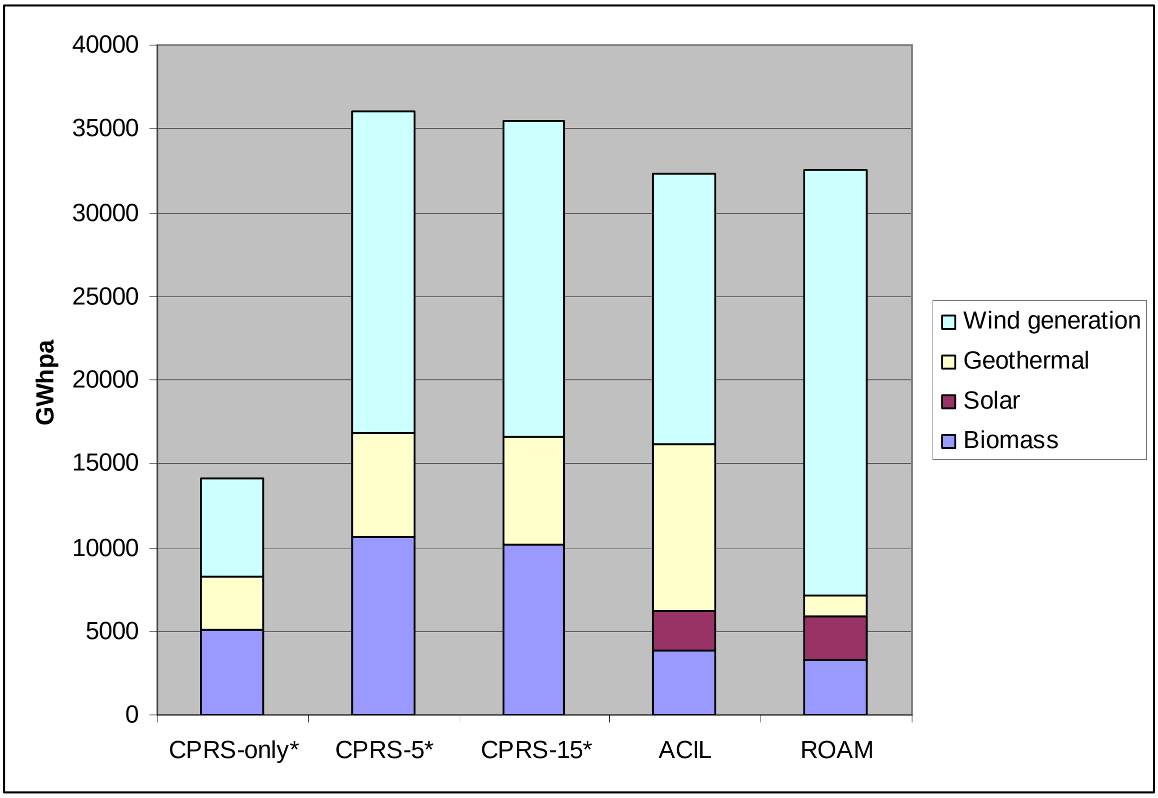
Each model finds that new renewables are likely to provide approximately 11% of new power generation above the 2008 level by 2020 (CRA predicts a higher 2020 load, with the majority of extra generation coming from new gas plant.).

Only the CRA study assumes that CCS technology is commercially available on a large scale by 2020.

Generation results - renewable technologies

Figure 6.7 shows the predicted generation mix for renewable technologies, comparing ROAM's assumptions with the MMA study and the ACIL Tasman study. For the three MMA scenarios (CPRS-only, CPRS-5 and CPRS-15) the values represent total renewables in 2020 (excluding hydro), while for ACIL and ROAM data show just new renewables above the 2008 level.

Figure 6.7 Predicted mix of new renewables generation in 2020 (GWh) (MMA, ACIL Tasman, ROAM)



* These values refer to total renewables excluding hydro, while the ACIL and ROAM data refers to new generation above 2008 levels.

The CRA report is compared to the ACIL Tasman report in Figure 6.8 below (generation capacity in MW rather than actual (or sent out) generation in GWh is compared).

Figure 6.8 Predicted mix of new renewables/clean energy capacity in 2020 (MW) (ACIL Tasman, CRA)

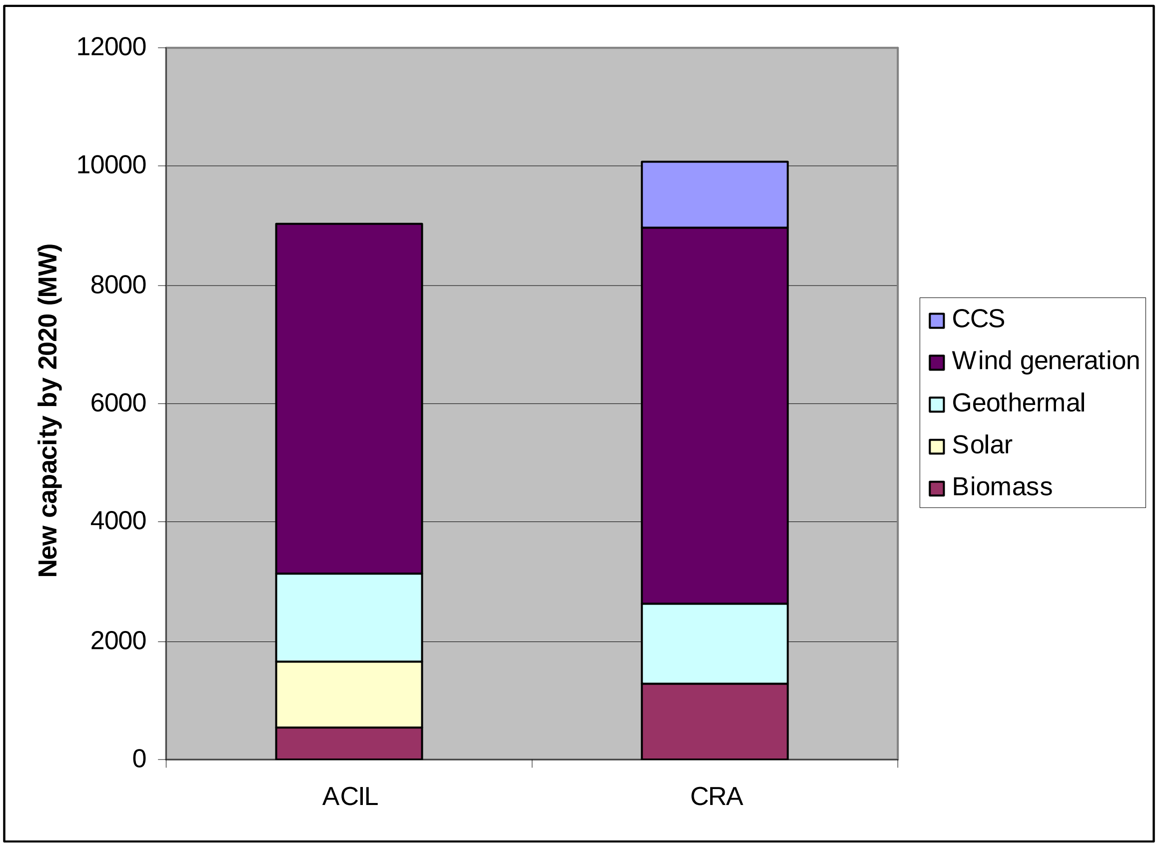


Figure 6.7 and Figure 6.8 show that there is common agreement between studies that the majority of renewable investment will be in wind generation. However, most studies assume a significantly more substantial contribution from geothermal energy than ROAM. This is due to low projected cost assumptions for geothermal energy. ROAM believes this technology unlikely to be feasible on a large scale pre-2020.

The ACIL Tasman model includes the largest amount of geothermal energy, predicting 1500 MW of generation operating on the Cooper Basin in South Australia, sending energy to the Queensland and South Australia networks via new transmission. The ACIL Tasman results are (aside from ROAM) the only ones to include solar in the 2020, consisting of a mix of solar thermal and solar PV. ACIL Tasman takes a conservative view on wind, particularly in South Australia where wind energy was scaled back due to a “severe” effect on the South Australian pool price.

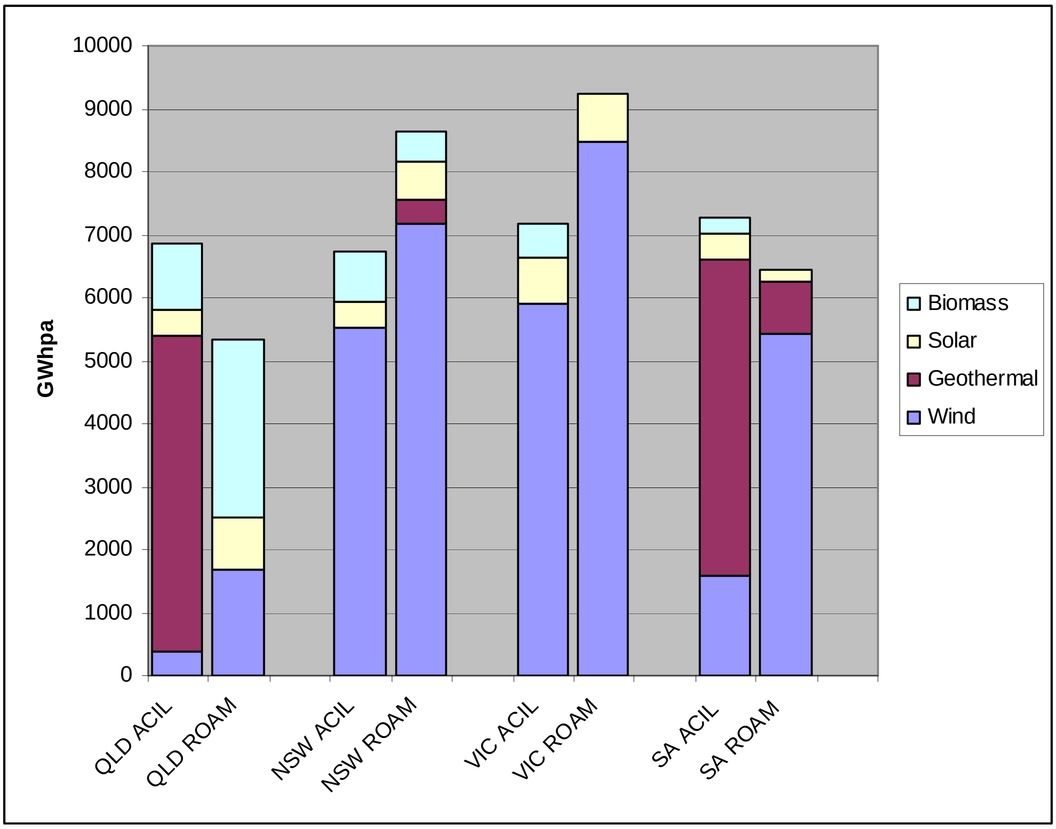
The MMA report assumes geothermal energy will not be commercially viable until 2017, and predicts a significant contribution from biomass.

The CRA models also favour biomass over geothermal (as compared to ACIL Tasman), but also include a significant about of Carbon Capture and Storage generation, which was assumed not to be technologically viable in 2020 by the other reports.

For comparison, ROAM's research suggests that solar thermal shows more promise of being commercially and technically viable in 2020 than geothermal, as described earlier in this section. Due to its proven abilities and low cost, ROAM expects wind power to be the major contributor to 2020 renewables. (In later years, wind growth will be more limited, for reasons outlined earlier). CCS is not expected to be commercially available by 2020.

The inclusion, in particular, of large amounts of geothermal divided between Queensland and South Australia significantly flattens the distribution of renewable energy use across the states, as shown below. In particular, wind generation in South Australia and Queensland is significantly reduced.

Figure 6.9 New renewables in 2020 by state for ACIL Tasman and ROAM models



Box 8 – Renewable technology assumptions review
All studies assume that wind generation will be the most significant contributor to the expanded RET. Most studies also assume a significant contribution from geothermal energy, although ROAM's research suggests that this technology is unlikely to be commercially feasible on a large scale by 2020, and forecasts a much lower contribution. Conversely, most studies take a conservative view of solar energy, whereas ROAM's research suggests that solar thermal technology shows great promise and could be a significant contributor to the expanded RET. Biomass is assumed by all studies to play a moderate role.

7) TRANSMISSION CONGESTION

The expanded Renewable Energy Target represents a significantly larger quantity of renewable energy entering the market. Renewable technologies (such as wind) are often located in remote areas with relatively weak transmission grids. This means that a large penetration of renewable energy under the CPRS and RET will have significant implications for the transmission grid. The CPRS is expected to change the dispatch order of plants, which ROAM has also shown has extensive transmission congestion implications. ROAM therefore considers transmission congestion to be an essential consideration for answering the questions posed by the AEMC, not least due to the effect of transmission limitations on pool prices and generator revenues.

ROAM is uniquely positioned to comment on transmission congestion, since ROAM's *2-4-C* model is the only NEM model that takes sophisticated modelling of transmission constraints into account. This is evident due to the lack of modelling results from other parties covering this particular topic.

7.1) MODELLING TRANSMISSION CONGESTION

ROAM uses the official 'ANTS constraint equations' provided annually by NEMMCO to model transmission limitations in the NEM. ROAM includes all existing and future generators (renewable or conventional) in the formulation of the ANTS constraint equations in their appropriate ANTS zones. This is critical to delivering accurate modelling results as the pattern of generation dispatch affects transmission limits greatly.

The ANTS constraint equations as formulated by NEMMCO incorporate *committed* network upgrades and also include 'routine augmentations' which take the form of small upgrades to line capabilities (eg. those that might result via the installation of an extra transformer or small SVC). They do not include any major proposed transmission upgrades. Note that without these progressive modifications, the ANTS constraint equations would function correctly only for around two years, after which major congestion would occur across the NEM.

Box 9 – Transmission congestion
ROAM considers transmission congestion to be a major area for consideration when implementing the CPRS and the RET. ROAM is uniquely positioned to comment on transmission congestion, since ROAM's *2-4-C* model is the only NEM model that takes sophisticated modelling of transmission constraints into account. This is evident due to the lack of modelling results from other parties covering this particular topic. In ROAM's simulations, congestion becomes a major issue in SWQ from around 2016-17 even in the absence of the expanded RET. This demonstrates that the area could be a candidate for significant transmission reinforcement at around that time.

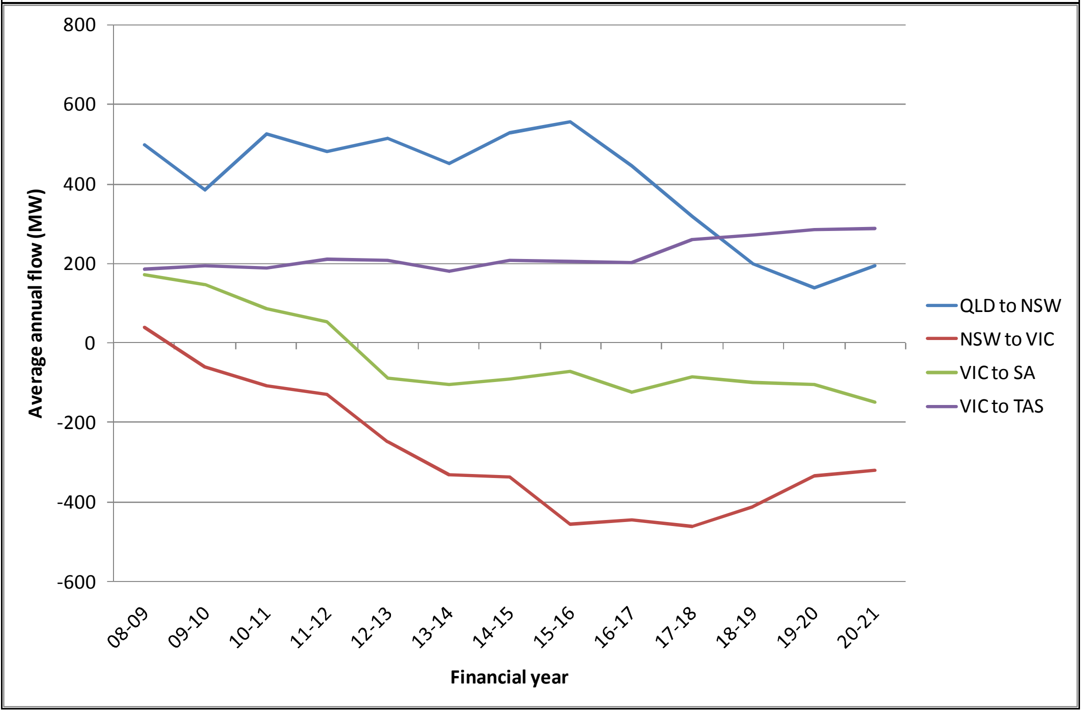
7.2) ROAM'S MODELLING RESULTS

7.2.1) Inter-regional Interconnector flows under the RET

Average annual inter-regional interconnector flows from ROAM's modelling of the RET are shown in Figure 7.1. The following points are evident:

- Flows from QLD to NSW are relatively unchanged by the expanded RET until post 2015-16, after which point they reduce.
- The NSW-VIC interconnector initially has average flows into VIC, but reverses under the expanded RET, with exports from VIC to NSW increasing steadily to 2015-16. This is most probably due to the large quantities of wind planted in VIC and SA.
- VIC shows increasing exports to TAS post 2015-16 due to large quantities of wind installed in VIC
- SA becomes a net exporter from 2012-13 due to large quantities of wind installed in SA.

Figure 7.1 – Average annual interconnector flows



The following figures show the flow durations for the major interconnectors, which represent the predominant flow patterns. Higher percentages of time at specific flows typically represent the occurrence of congestion for that interconnector, either due to inter-regional flow limits or intra-regional flow limits.

Figure 7.2 shows the average flow durations from NSW to QLD. The dramatic change between 2015-16 and 2020-21 is indicative of the rapid onset of transmission constraints in QLD in the later years of the study. This causes flows to shift to predominantly NSW to QLD in the later years of the study. It is likely that these transmission constraints will be alleviated by upgrades in these later years.

The Queensland to New South Wales interconnector is also constrained in a northerly direction well below its notional limit of around 500MW north by intra-regional constraints.

Figure 7.2 – Average flow durations (QLD to NSW)

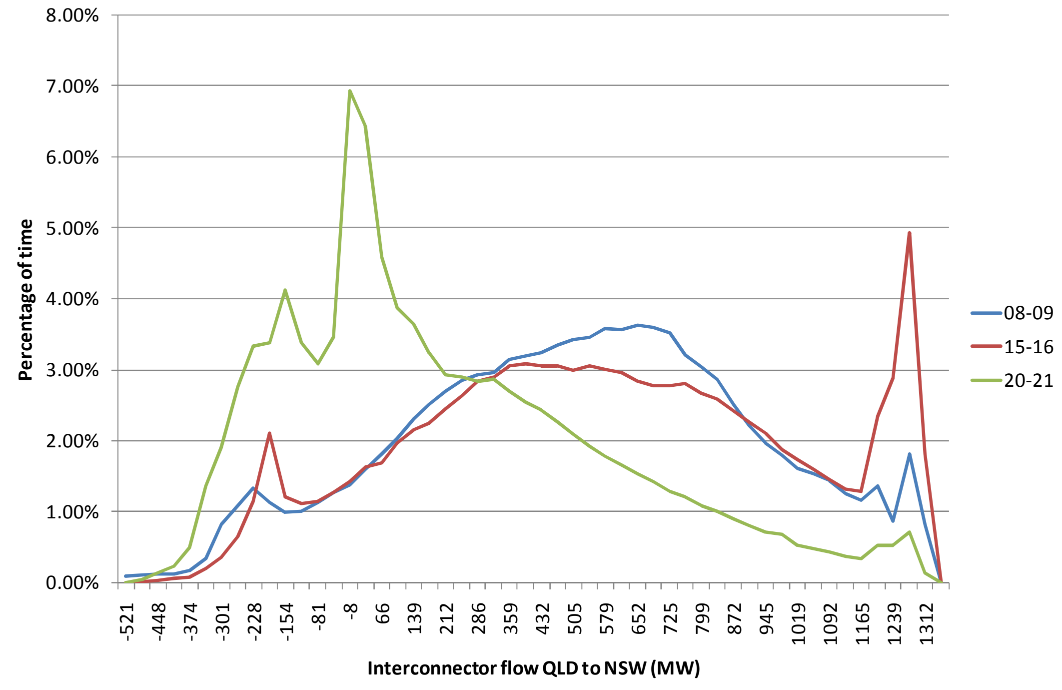


Figure 7.3 – Average flow durations (NSW to VIC)

Figure 7.3 shows that the flow durations between NSW and VIC change in nature substantially between 2008-09 and 2015-16, shifting from flows going from NSW to VIC

on average, to flows in the other direction. However, the interconnectors do not frequently flow at their limit in either direction in any year.

Figure 7.4 – Average flow durations (VIC to SA)

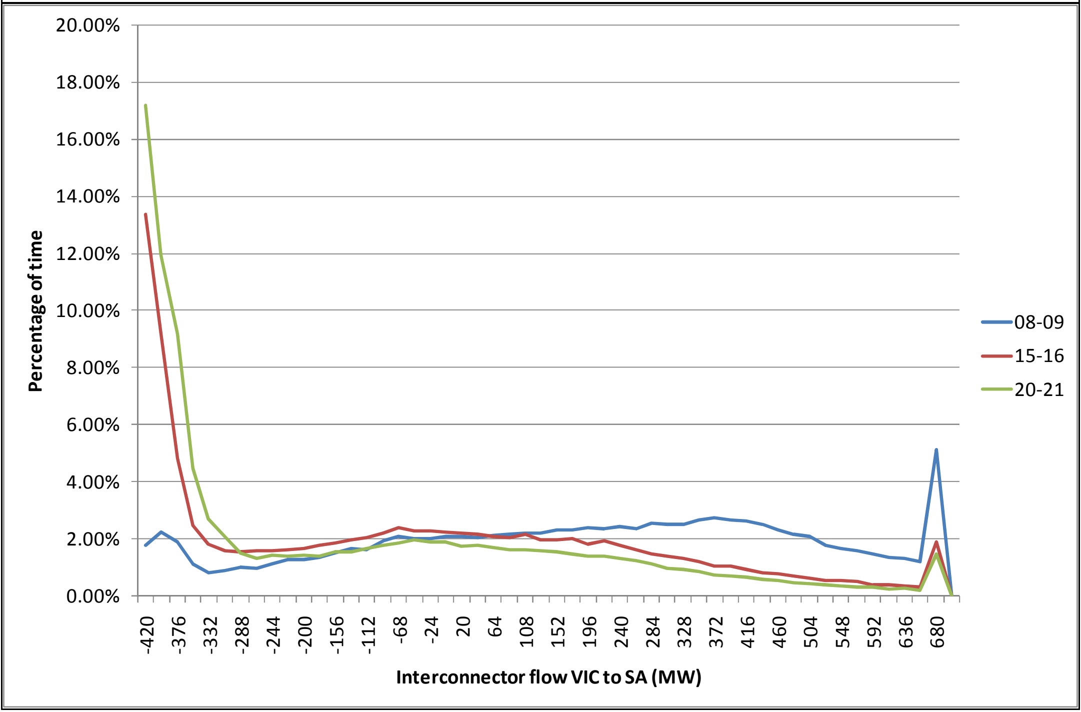
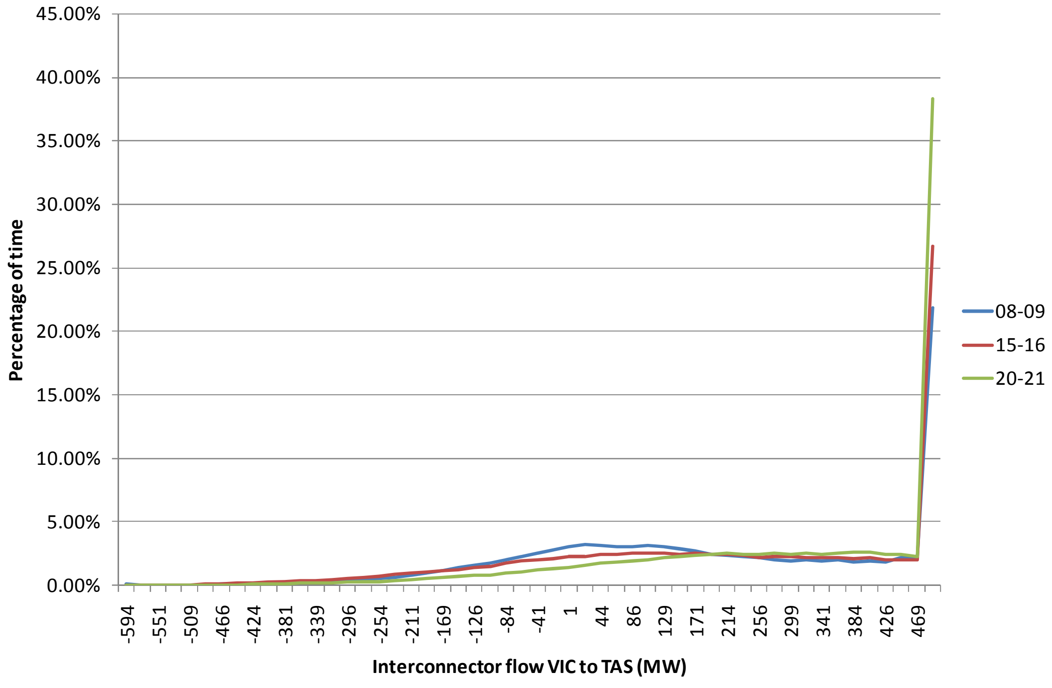


Figure 7.4 shows that as the amount of installed wind increases, the interconnector more frequently exports power from SA to VIC at the limit. This is forecast to increase to 18% of the time by 2020.

Figure 7.5 – Average flow durations (VIC to TAS)



As shown in Figure 7.5, Basslink is importing energy to TAS at its limit for an increasing proportion of the time (almost 40% by 2020) as the amount of wind generation installed in Victoria increases. Wind developments in Tasmania are not expected to proceed in the same proportion as the mainland despite the superiority of Tasmania's wind resources, as Tasmanian ancillary service costs rapidly escalate to uneconomic levels with increasing proportions of wind in the generation mix. This is because FCAS ancillary services need to be imported across Basslink, affecting energy prices as well as ancillary service prices.

Box 10 – Inter-regional transmission flows
ROAM's modelling shows that inter-regional transmission flows change significantly with the growth of the RET. This suggests that the amount of renewable generation anticipated to enter the market will have a significant impact upon inter-regional transmission flows, and should be the subject of significant further analysis.

7.2.2) Intra-regional constraints under the RET

ROAM's forecast incidence of congestion over ANTS flowpaths (including intra-regional paths) is depicted in Figure 7.6. This shows the percentage of time each flowpath is forecast to become congested due to transmission flows reaching their allowable limits for two comparative cases:

1. The RET case in the top chart,
2. The comparison case in the bottom chart; this case did not include renewable generators in the ANTS constraints equations, hence they did not contribute to transmission congestion).

Flowpaths that did not show any significant level of congestion are not displayed in order to maintain the readability of the chart. Note that these figures include congestion in either direction on a flowpath.

ROAM cautions that the exact numbers shown in these graphs should not be regarded as absolute. They are based upon the number of times that the ANTS constraint equations were observed to bind[17] in the LP solution, which does not necessarily correspond exactly with the amount of time that an intraconnector was constrained. Each constraint equation was associated with a particular flow path via the information provided in the ANTS constraints workbooks (supplied by NEMMCO). In reality, each constraint equation may actually involve several flowpaths, and cannot necessarily be assigned solely to a single flowpath. This means that the results shown in the following charts should be considered to be indicative of general areas of congestion only, and the actual percentages should be only considered a guide as to the magnitude of congestion in the area.

In both cases the incidence of congestion over most flowpaths has been forecast to increase significantly in the study timeframe. This outcome is to be expected; with increasing customer load, and a large amount of new plant locating in a transmission grid that is essentially constant, congestion may be expected to increase over time. Where congestion on a given flowpath reduces over time, it is likely due to increases in congestion elsewhere which prevent that flowpath congesting as significantly. In other cases, the minor committed or routine upgrades built into the ANTS constraints may relieve network congestion for some time. The expanded RET may also have the effect of reversing average flows across some interconnectors, thereby reversing the direction of congestion. Due to the complexity of the interaction of generators with the constraint equations, it is difficult to derive a generalised view on constraints between ANTS zones, except for specific locations such as South Australia, where intermittent renewables can be expected to maintain or increase the incidence of extreme flows in either direction, as shown in Figure 7.4.

In the RET case, increasing congestion is most prevalent on the SESA-VIC flowpath and is also significant on the MEL-NVIC, NVIC-SNY and NNS-SEQ/NNS-SWQ flowpaths[18]. Wind generation is the key factor here, although new thermal generation will play a role. It may be observed that flowpaths in and between the SA and VIC regions congest heavily early in the study, as these regions are heavily planted with wind generation throughout the forecast. In contrast, wind generation in NSW is less significant (in comparison to regional demand), until 2018-19, where a ~1000MW farm was assumed to commence operation. This was observed to coincide directly with a significant increase in congestion between NNS (Northern NSW) and SEQ/SWQ (South QLD).

Figure 7.6, a comparison of the RET case with the comparison case (no constraints for new generators) shows how much the inclusion of new generators in the constraint equations contributes to congestion, and which flowpaths are most affected.

---

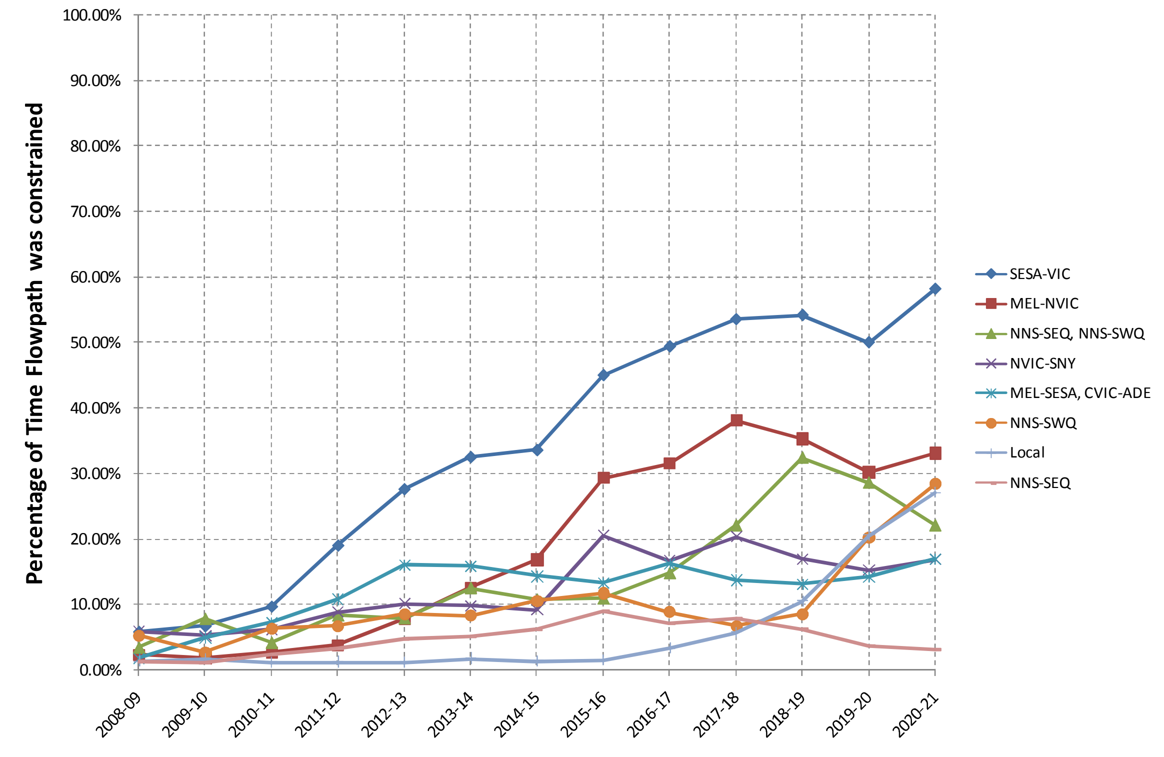
[17] A binding condition is defined as an event where transmission flow is at the calculated limit of the transmission path.

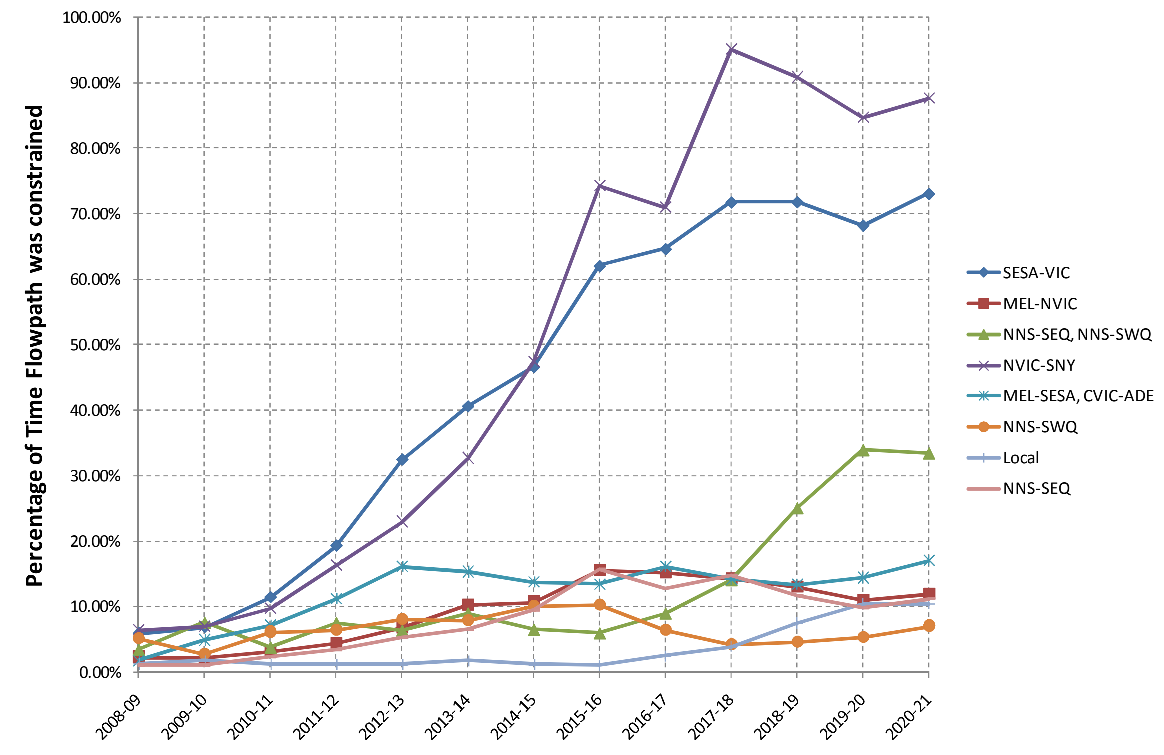
[18] Flowpaths are as defined in the 2007 ANTS, part of the NEMMCO SOO

- Congestion on the SESA-VIC flowpath *increased* by about 10%, indicating that the inclusion of new generators in the constraints benefits this flowpath by a small amount. This is because congestion in other areas serves to effectively relieve congestion on the SESA-VIC flowpath.
- Congestion on the MEL-NVIC flowpath is decreased by about 20%, indicating that the inclusion of new generators in the constraints drives up congestion on this flowpath to a significant degree. This provides an example of the behaviour described in the point above; the congestion is generally moved northwards when new generators are ignored in the constraint equations.
- Congestion on the NNS-SEQ/NNS-SWQ flowpath is very similar in both cases, indicating that inclusion of the new generators in the constraints does not contribute significantly to congestion on this flowpath; that is, the locational issues were found to be less important than the actual amount of generation going into NSW.
- Congestion on the NVIC-SNY flowpath is *increased* by as much as 70%. This is the same effect observed when looking at comparison case A against the Base Case, but is magnified significantly due to the much larger (at times) amount of generation attempting to flow Northwards (consider the *energy* difference between the RET case and the Equivalent Baseload Case). Again, the cause of this congestion is due to effectively removing congestion in other areas further south; that is, the congestion has been referred North by removing limitations to the South. This outcome is highly significant, as congestion across the NVIC-SNY flowpath effectively will be seen as binding the connection between Victoria and New South Wales.

Box 11 – Intra-regional transmission congestion
The incidence of congestion over most flowpaths has been forecast to increase significantly by 2020, both under the RET and in the reference case (without the RET). This is due to increasing customer load, and a large amount of new plant locating in a transmission grid that is essentially constant. On some flowpaths, congestion reduces over time, which is likely due to increases in congestion elsewhere which prevent that flowpath congesting as significantly. In the RET case, increasing congestion is most prevalent on the SESA-VIC flowpath and is also significant on the MEL-NVIC, NVIC-SNY and NNS-SEQ/NNS-SWQ flowpaths. Wind generation is the key factor here, although new thermal generation will play a role.

Figure 7.6 – Base Case (Expanded RET) (top chart), compared with Comparison Case B (No constraints on new generators) (bottom chart)





7.2.3) Wind farms

In ROAM's modelling, wind farm units attempt to achieve a pre-defined operational profile which has been derived from real (historical) wind data and turbine parameters. This means that within a given forecast, the actual achieved dispatch may be compared to their target value for each half hour to give an assessment of how much of their available energy is not able to be utilised, either due to congestion, insufficient demand and export capability, or a combination of both.

Table 7.1 shows the amounts by which each wind farm 'zone' in the NEM fell short of the targeted output in each year due to the issues outlined above.

These results show that the introduction of wind farms in the NSA and SESA zones of South Australia causes significant volume shortfalls from 2011-12 (for NSA) and from 2015-16 (for SESA). The ADE (Adelaide) zone also shows significant volume shortfalls at times when the wind is strong from 2017-18. The specific existing wind farms listed all show significant volume shortfalls from 2015-16 (these wind farms are all located in South Australia).

The LV (Latrobe Valley) zone in Victoria is mildly affected from 2017-18 onwards.

Table 7.1 – Wind farms annual shortfalls to total available energy (M50)

	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21
Wind Farms NSW - CAN	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	1%	1%
Wind Farms NSW - NCEN	0%	0%	0%	0%	0%	0%	0%	1%	0%	1%	1%	2%	2%
Wind Farms NSW - NNS	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	1%	1%
Wind Farms QLD - CQ	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Wind Farms QLD - NQ	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Wind Farms QLD - SEQ	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%
Wind Farms QLD - SWQ	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Wind Farms SA - ADE	0%	0%	1%	1%	5%	6%	7%	10%	13%	16%	16%	18%	18%
Wind Farms SA - NSA	1%	3%	6%	14%	29%	31%	30%	40%	50%	54%	53%	53%	60%
Wind Farms SA - SESA	0%	0%	0%	4%	9%	10%	10%	20%	31%	34%	34%	55%	60%
Wind Farms TAS - TAS	0%	0%	0%	0%	0%	0%	0%	1%	0%	1%	0%	0%	0%
Wind Farms VIC - CVIC	0%	0%	0%	0%	1%	1%	2%	3%	3%	5%	5%	5%	6%
Wind Farms VIC - LV	0%	0%	0%	0%	0%	0%	3%	7%	6%	10%	9%	9%	9%
Wind Farms VIC - MEL	0%	0%	0%	0%	0%	0%	1%	1%	1%	2%	3%	4%	4%
Canunda Wind Farm	0%	1%	2%	3%	13%	15%	15%	27%	39%	43%	42%	41%	40%
Cathedral Rocks Wind Farm	0%	0%	2%	2%	10%	12%	13%	24%	36%	41%	41%	40%	38%

Table 7.1 – Wind farms annual shortfalls to total available energy (M50)													
	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16	16-17	17-18	18-19	19-20	20-21
Lake Bonney Wind Farm	0%	0%	1%	1%	6%	8%	9%	19%	30%	36%	35%	34%	33%
Mt Millar Wind Farm	0%	0%	1%	1%	6%	7%	8%	19%	29%	34%	33%	33%	32%
Wattle Point Wind Farm	0%	0%	1%	1%	5%	7%	8%	19%	30%	35%	35%	35%	35%

It is likely that with such severe levels of curtailment, wind farms would not be constructed in the NSA or SESA zones (in particular) beyond 2015-16 unless transmission upgrades were performed to alleviate the issue, as with such a level of curtailment they would be unlikely to be economically viable. These results suggest that it is likely to be more feasible for these wind farms to be constructed in other zones.

Analysis of the wind trace data shows that these significant levels of curtailment in South Australia are largely due to *inter*-regional transmission congestion as well as *intra*-regional transmission congestion. Table 7.2 shows the percentage of the time that the aggregated output of wind farms by state actually exceeds the regional demand in that state. From 2016-17 onwards the state-wide demand is exceeded in SA at times by the wind generation alone. When capacity from thermal plants offered below $0/MWh is also taken into account (that is, capacity bid to avoid de-commitment, and which undercuts the wind generators on price), the generation exceeds the state demand in SA between 17% and 55% of the time, increasing progressively as more wind generation is commissioned. This effectively means that there is a large surplus of generation in the region attempting to export to the rest of the NEM.

The export capacity of each state varies continuously in accordance to the constraint equations. However, by using the nominal capacities of each interconnector, we can roughly estimate the *minimum* amount of time that the sum of the wind farm output and capacity bid at negative values in each state exceeds the sum of the demand in that state and its export capability. This is shown in the final three columns of Table 7.2. Even when taking the maximum realistic export capacity of the state into account, South Australia shows significant periods where wind energy is not able to be utilised.

These results strongly suggest that significant transmission upgrades to accommodate large exports out of South Australia are required to allow this amount of wind generation to be viable in the region.

NSW and VIC show less severe effects, since these regions have much larger demand and hence a lower relative penetration of wind farms.

Table 7.2 – Percentage of time wind exceeds demand (Medium energy, 50% POE demand)									
	Percentage of time wind alone exceeds state-wide demand			Percentage of time wind and negative bidding thermal plant exceed state-wide demand[19]			Percentage of time wind + negative bidding thermal plant exceeds state-wide demand + nominal state export capacity[20]		
	SA	NSW	VIC	SA	NSW	VIC	SA	NSW	VIC
2007	0.00%	0.00%	0.00%	17.59%	5.44%	24.25%	0.06%	0.00%	0.00%
2008	0.00%	0.00%	0.00%	23.62%	4.54%	35.29%	1.37%	0.00%	0.00%
2009	0.17%	0.00%	0.00%	32.30%	4.32%	39.00%	5.51%	0.00%	0.00%
2010	0.30%	0.00%	0.00%	32.25%	4.95%	39.37%	6.24%	0.00%	0.00%
2011	2.68%	0.00%	0.00%	39.29%	5.00%	42.03%	12.79%	0.00%	0.00%
2012	2.52%	0.00%	0.00%	37.60%	4.19%	42.15%	12.07%	0.00%	0.05%
2013	2.55%	0.00%	0.00%	37.35%	4.38%	45.30%	11.93%	0.00%	0.36%
2014	2.68%	0.00%	0.00%	36.86%	3.80%	46.68%	12.01%	0.00%	0.79%
2015	5.55%	0.00%	0.00%	40.54%	2.73%	48.20%	16.52%	0.00%	1.95%
2016	10.57%	0.00%	0.00%	45.55%	1.93%	44.56%	22.36%	0.00%	1.43%
2017	12.25%	0.00%	0.00%	46.60%	1.63%	45.55%	23.95%	0.00%	2.31%
2018	11.82%	0.00%	0.00%	45.65%	3.74%	42.55%	23.32%	0.00%	2.02%
2019	15.87%	0.00%	0.00%	48.83%	3.82%	41.39%	27.35%	0.00%	2.03%
2020	23.72%	0.00%	0.00%	55.37%	3.00%	38.62%	36.01%	0.00%	1.78%

Other market modelling studies often include a limitation on the amount of wind penetration into a region (for example, the MMA report to Treasury[21] included a limitation of wind development of 25% of peak demand). The study above did not include this limitation, since it was intended to investigate the impacts of high wind penetration upon transmission congestion. It should be noted that South Australia is already very close to 25% wind penetration, and the MMA assumption therefore is likely to be prohibitively limiting for wind development in that region. Wind development within South Australia was only permitted in the MMA model if the transmission network to Victoria was upgraded (by the model).

ROAM's model explicitely models the details of the transmission network (including intra-regional congestion), and is therefore able to allow continued development in wind

[19] The amount of negative bidding plant has been calculated using a simplistic analysis of the maximum amount of negative bidding plant at any time. Numbers are therefore indicative only.

[20] The amount of negative bidding plant has been calculated using a simplistic analysis of the maximum amount of negative bidding plant at any time. Numbers are therefore indicative only. The nominal export capabilities of each state is as listed in the NEMMCO Statement of Opportunities 2007.

[21] Impacts of the Carbon Pollution Reduction Scheme on Australia's Electricity Market. Report to Federal Treasury by McLennan Magasanik Associates (MMA). 27th October 2008.

generation until wind farms experience uneconomical reduction in their ability to export energy to the grid. ROAM's analysis indicates that South Australia's transmission system can incorporate up to 50% of peak demand in wind generation without serious transmission congestion issues. Due to the very large number of wind projects proposed for development in South Australia, ROAM routinely includes wind generation to this higher level in simulations of the RET.

7.2.4) Wind correlation between regions

The amount of correlation between the wind generation in each state is important. If there is high correlation in time between the aggregated output of the wind in different states, transmission congestion on regional interconnectors will be exacerbated.

The correlation coefficients for the aggregated wind in each region are shown in Table 7.3. These coefficients show that there is a reasonable correlation between wind in SA and VIC, some correlation between wind in:

- NSW and VIC
- TAS and VIC
- NSW and SA,

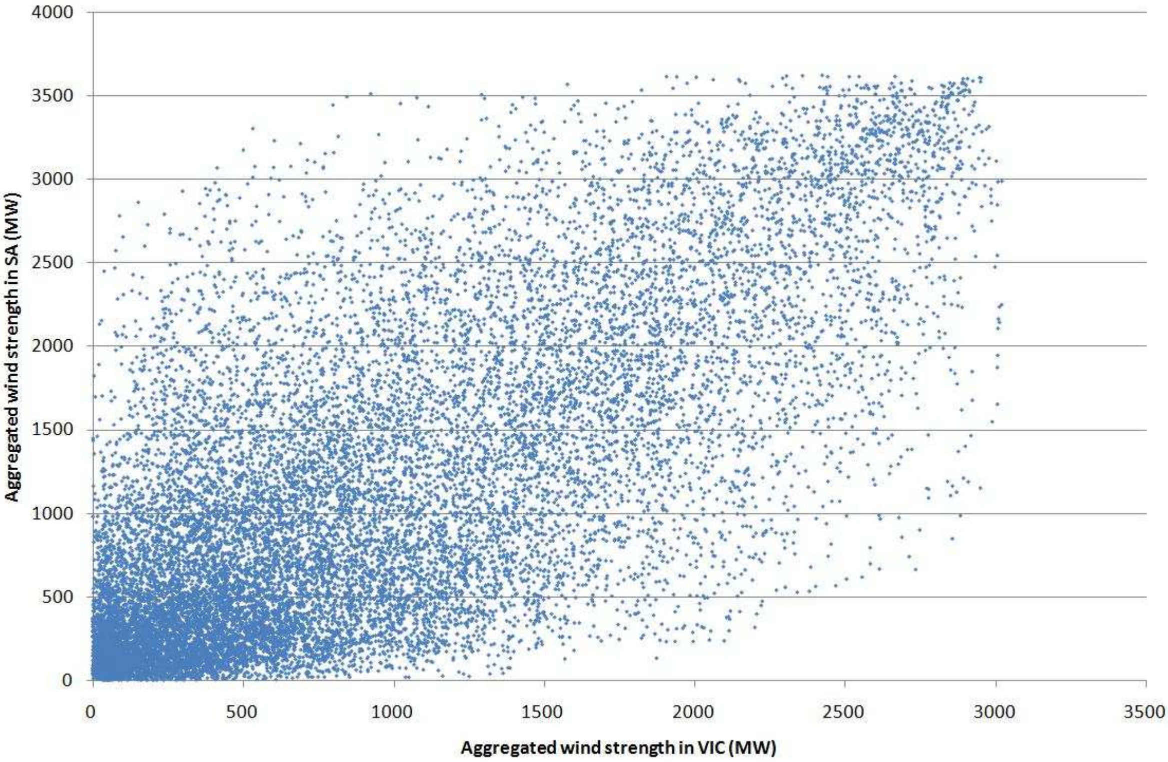
and very little correlation between the other combinations of states.

Table 7.3 – Correlation coefficient between wind in different regions

	VIC	SA	NSW	QLD	TAS
VIC	x	0.7408	0.5711	0.2371	0.5473
SA	0.7408	x	0.5476	0.3363	0.3866
NSW	0.5711	0.5476	x	0.3363	0.3866
QLD	0.2371	0.3363	0.3363	x	0.1602
TAS	0.5473	0.3866	0.3866	0.1602	x

The correlation between the wind in SA and VIC is depicted graphically in Figure 7.7.

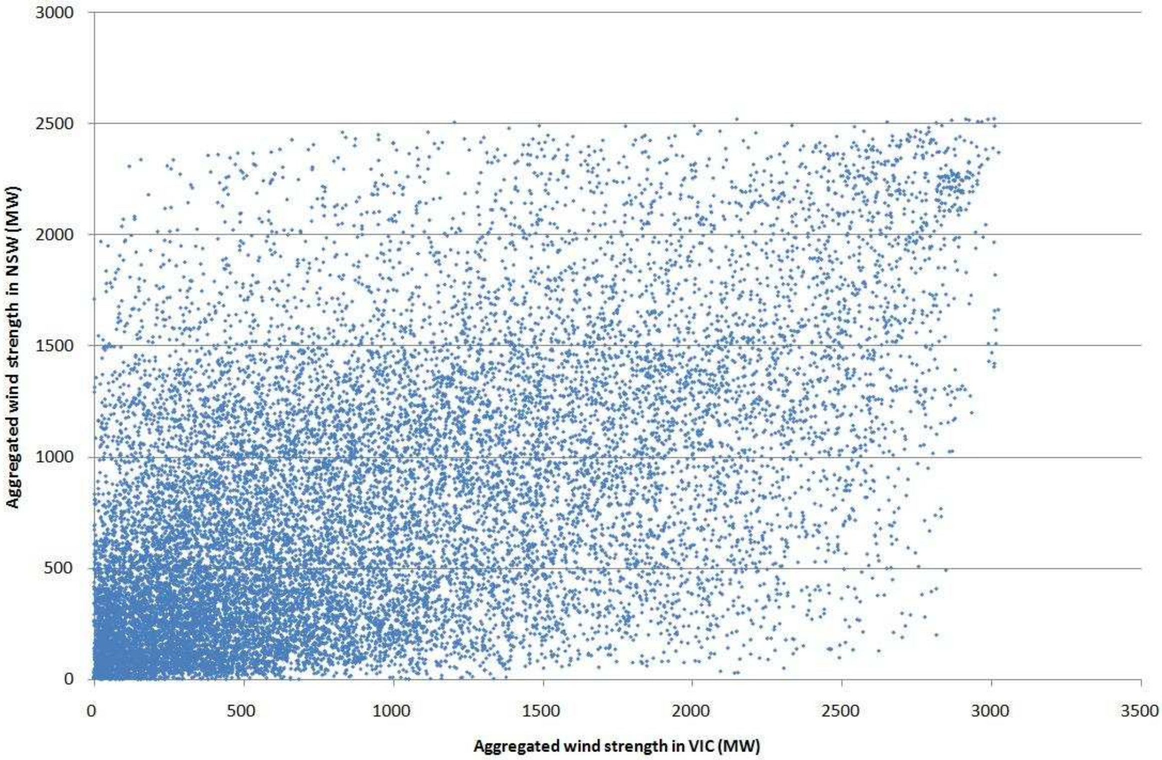
Figure 7.7 – Correlation of wind in SA and VIC



The relatively strong correlation of wind in SA and VIC likely further inhibits exports from SA to VIC in high wind times, as VIC is likely to have a sufficient generation within its regional boundaries.

For comparison, the correlation between the wind in NSW and VIC is shown in Figure 7.8. There is a comparatively lower degree of correlation between the wind in NSW and VIC, indicating that exports of excess wind energy from one to the other are likely to be more feasible.

Figure 7.8 – Correlation of wind in NSW and VIC



Box 12 – Impacts of transmission congestion on wind farms

Renewables, and particularly intermittent renewables exemplified by wind, are disadvantaged by location, lack of transmission, lack of native load, and drive lower pool prices in the regions where they are most likely to develop. Hence the amount of wind that may otherwise be market competitive is unlikely to be developed, leading to second order wind resources taking their place. To reduce this, steps need to be taken to avoid congestion, particularly between regions. Also, the effects of large quantities of wind on Marginal Loss Factors may be a further deterrent. Studies need to be undertaken to describe the tradeoff between expanded regulated transmission infrastructure (which should be a natural outcome of valuing losses more highly in the regulatory test of new lines), versus locating wind projects in areas where the wind resource is poorer but the transmission grid stronger.

7.3) TRANSMISSION CONGESTION UNDER THE CPRS

The CPRS will, by design, change the way in which generation plant is dispatched into the NEM. In general, plants with higher CO_2 emissions intensity will lose volume to plants with lower CO_2 emissions intensity. Significant changes to the actual plant operating across the NEM will drive different inter-regional transmission flows. This in turn will affect the congestion patterns that occur in the NEM.

The following set of figures examines congestion outcomes from ROAM modelling of the impact of the CPRS. They show the frequency by which the inter-regional interconnectors were found to be flowing at their maximum capability for a case without any CPRS, and one with a CPRS. Note that these figures assume a carbon price of $40/tonne of CO2 across the entire study.

Figure 7.9 and Figure 7.10 show the difference in inter-regional congestion between the Queensland and New South Wales regions. The CPRS results in a higher general level of congestion towards the north, and a corresponding reduction in congestion towards the south. This demonstrates that under the CPRS, generation in the southerly regions is somewhat more competitive relative to the situation without a CPRS in place. However, the difference in the overall level of congestion is not severe.

Figure 7.9 – Incidence of Congestion between NSW and QLD (North)

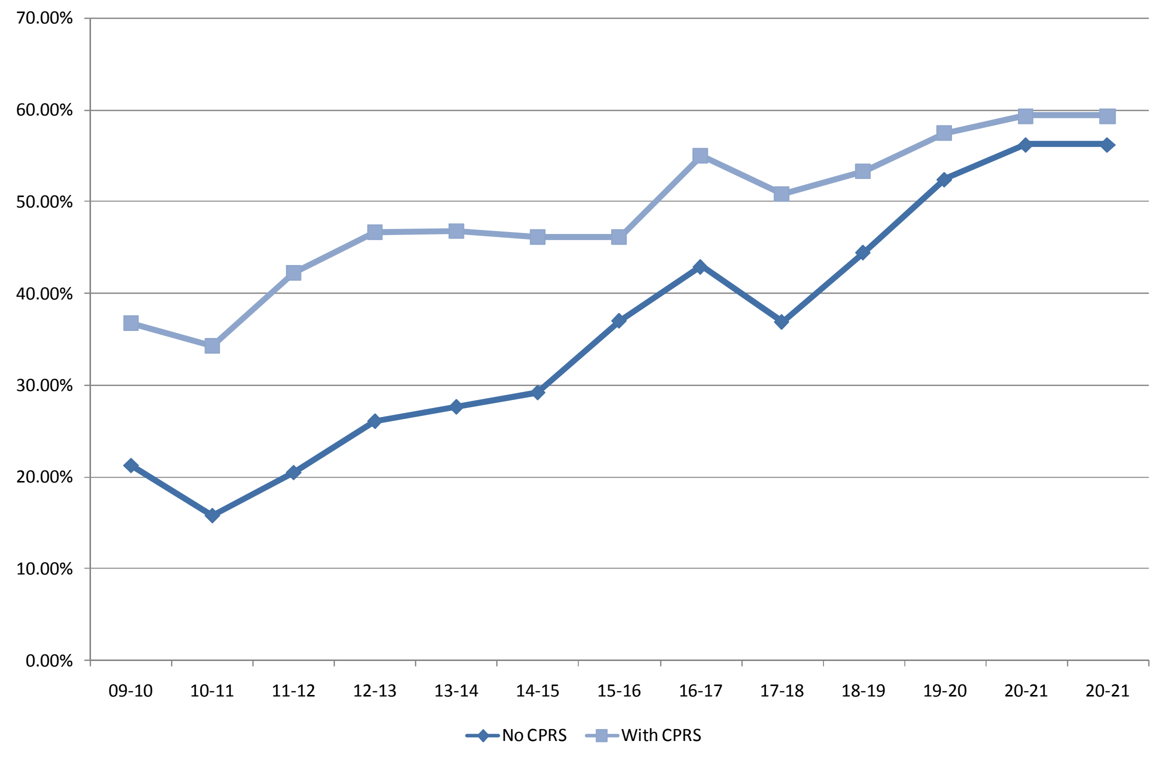


Figure 7.10 – Incidence of Congestion between QLD and NSW (South)

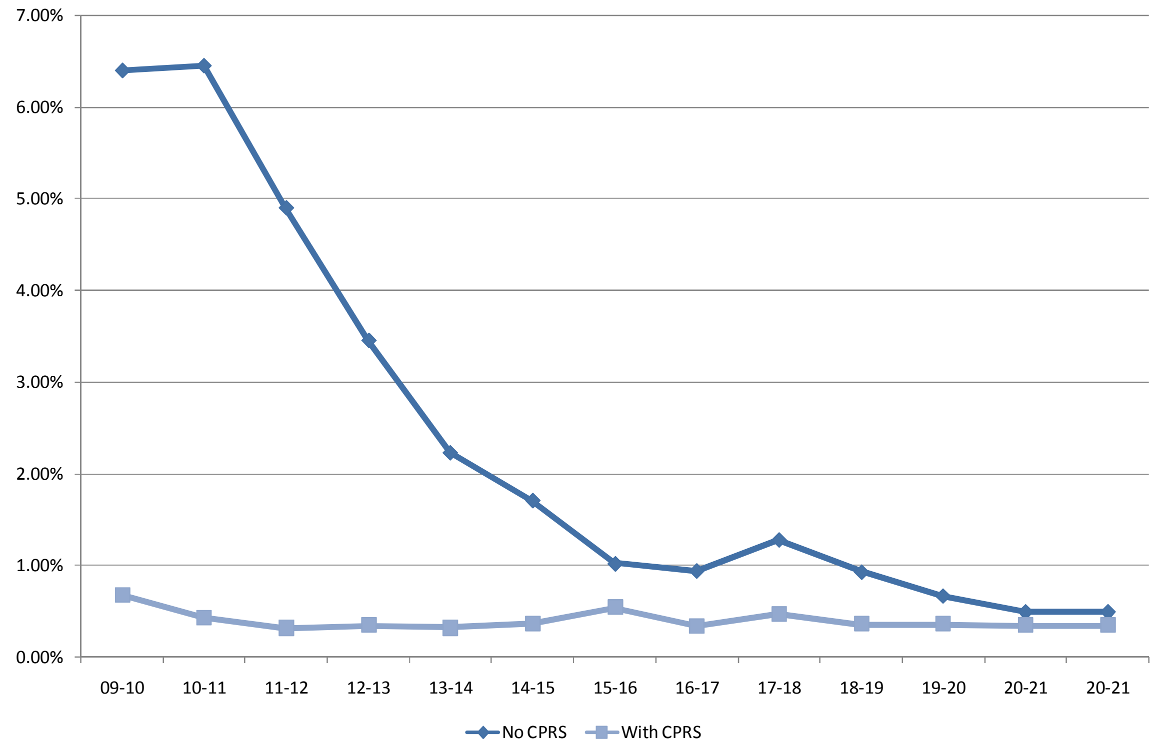


Figure 7.11and Figure 7.12 examine the impact of the CPRS on transmission congestion between Victoria and South Australia. In this case, the incidence of congestion was observed to increase in both directions. This suggests that under the CPRS, transmission flows tend towards becoming more extreme in either direction. The increase in congestion coming from South Australia into Victoria is a product of increasing the general competitiveness of plant in that region, which is largely gas, versus plant in Victoria which is largely brown coal.

Figure 7.11 – Incidence of Congestion between SA and VIC (East)

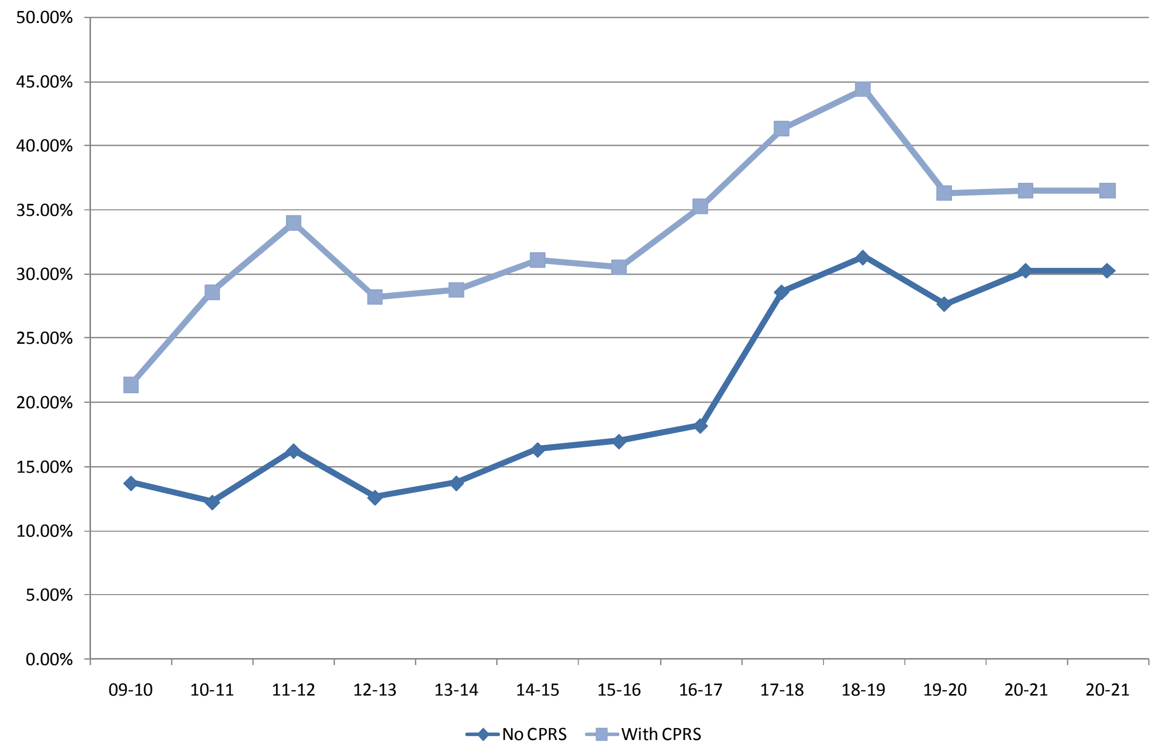


Figure 7.12 – Incidence of Congestion between VIC and SA (West)

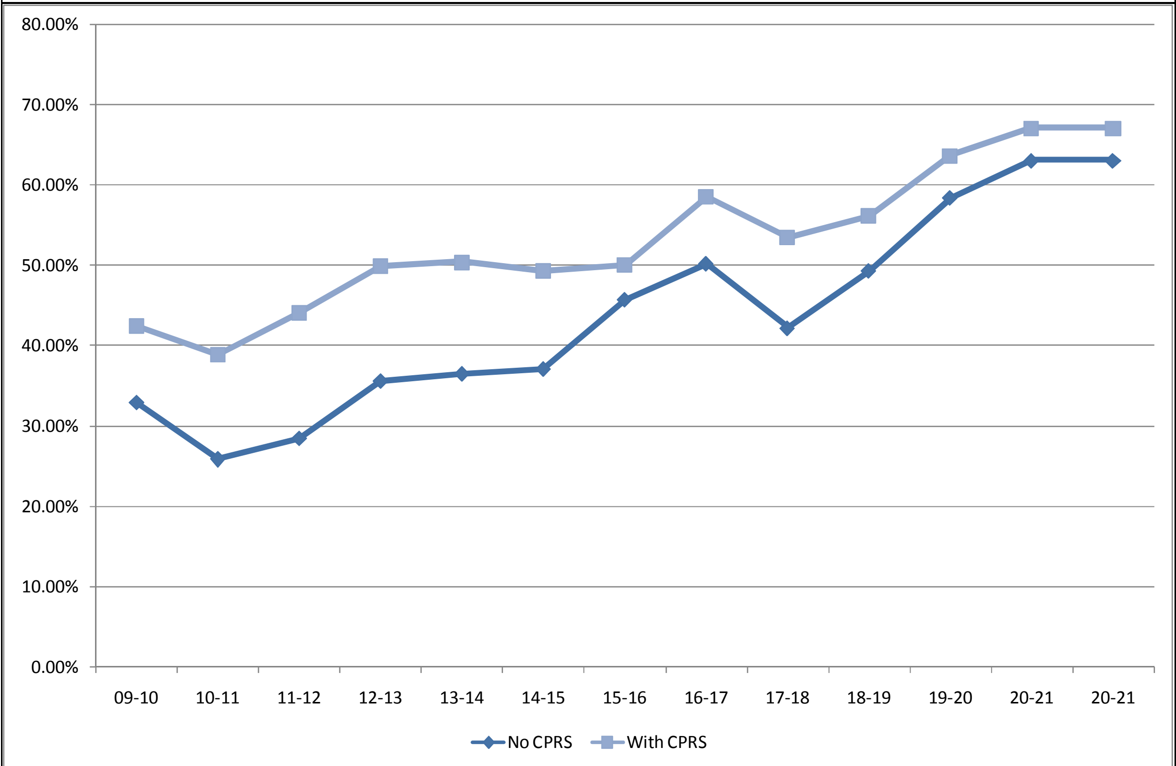
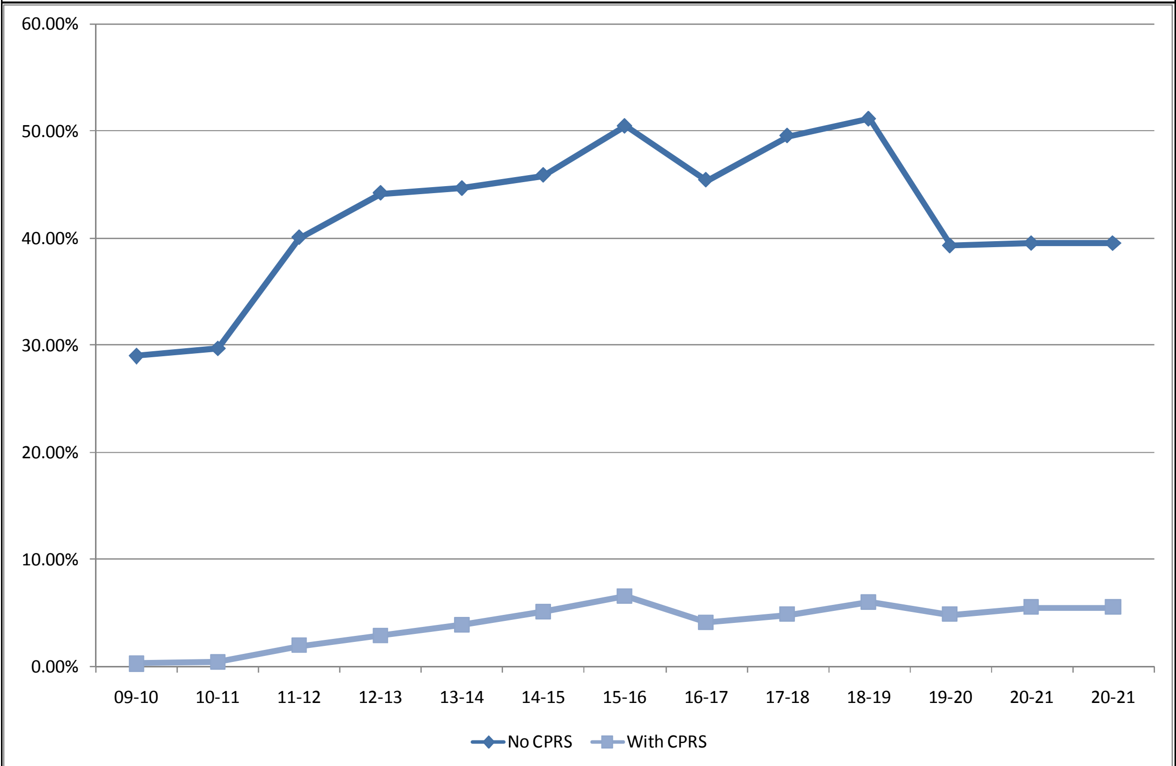


Figure 7.13, which shows the impact of the CPRS on congestion between Victoria and Tasmania, provides an example of how the CPRS may in fact decrease congestion significantly. In the case without the CPRS, Tasmania is heavily reliant upon imported cheap brown coal generation from Victoria. However, under the CPRS, brown coal is no longer as competitive and hence imports decline as Tasmania relies on its own largely renewable sources.

Figure 7.13 – Incidence of Congestion between VIC and TAS (South)



Box 13 – Effect of CPRS on transmission congestion
The key effect of the CPRS on transmission congestion is to reconfigure 'established' flow patterns between the regions of the NEM, and hence result in different patterns of congestion. However, the CPRS does not necessarily drive increases in transmission congestion in the NEM.

7.4) INTERACTION BETWEEN THE CPRS AND THE RET

Both the RET and the CPRS are expected to create increased potential for transmission congestion, although in combination the contribution of each is unlikely to be a simple summation. However, since the primary effect of the RET and the CPRS is to shift established patterns of congestion around the grid (rather than to dramatically increase the overall level of congestion) it is possible that the policies in combination may show no more congestion than each alone.

7.5) MODELLING OF TRANSMISSION CONGESTION BY OTHER PARTIES

ROAM's detailed modelling of the transmission system is relatively unique, with NEMMCO being the only other party able to perform transmission modelling at this level of detail. The studies reviewed in the BCA report[22] (ACIL Tasman[23] and CRA International[24]) do not include transmission constraints in their analysis (except by comment that it may be significant), which can be particularly problematic when considering large quantities of wind generation. MMA's modelling only includes very coarse grained modelling of inter-regional interconnectors with nominal limits.

7.6) TRANSMISSION INVESTMENT

The costs of transmission investment necessary to facilitate the introduction of substantial quantities of wind and geothermal energy into the grid are emphasized in a number of reports. ACIL Tasman estimates that $4 billion of investment in electricity transmission will be required under the ETS[25].

This is emphasized again in the Garnaut Review[26]:

> *Without major changes in the transmission infrastructure, new technologies will find it difficult to compete, even in circumstances in which they are expected to be highly competitive once compatible infrastructure has been established.*

ROAM agrees that the CPRS and RET are likely to require substantial transmission investment in support of renewable generation. This may be offset somewhat if distributed generation is supported with a high priority.

7.7) NEW GENERATORS CONNECTION ARRANGEMENTS

The AEMC have commented upon the impact of the CPRS and the RET in delivering increased levels of gas and renewable generation capacity to the market and the risks associated with connecting that new capacity to the grid.

As mentioned in the AEMC Scoping Paper[27],

---

[22] P. 116, Bringing specific company economic perspectives to bear on the ETS design, Report prepared for the Business Council of Australia by Port Jackson Partners Limited, 21 August 2008.

[23] ACIL Tasman, prepared for the Energy Supply Association of Australia (June 2008), The impact of an ETS on the energy supply industry.

[24] CRA International, prepared for the National Generators Forum (May 2008), Market modelling to assess generator revenue impact of alternative GHG policies.

[25] P. 10, ACIL Tasman, prepared for the Energy Supply Association of Australia (June 2008), The impact of an ETS on the energy supply industry.

[26] P. 448, The Garnaut Climate Change Review, Final report, October 2008.

[27] Review of Energy Market Frameworks in light of Climate Change Policies, Scoping Paper, AEMC, 10th October 2008.

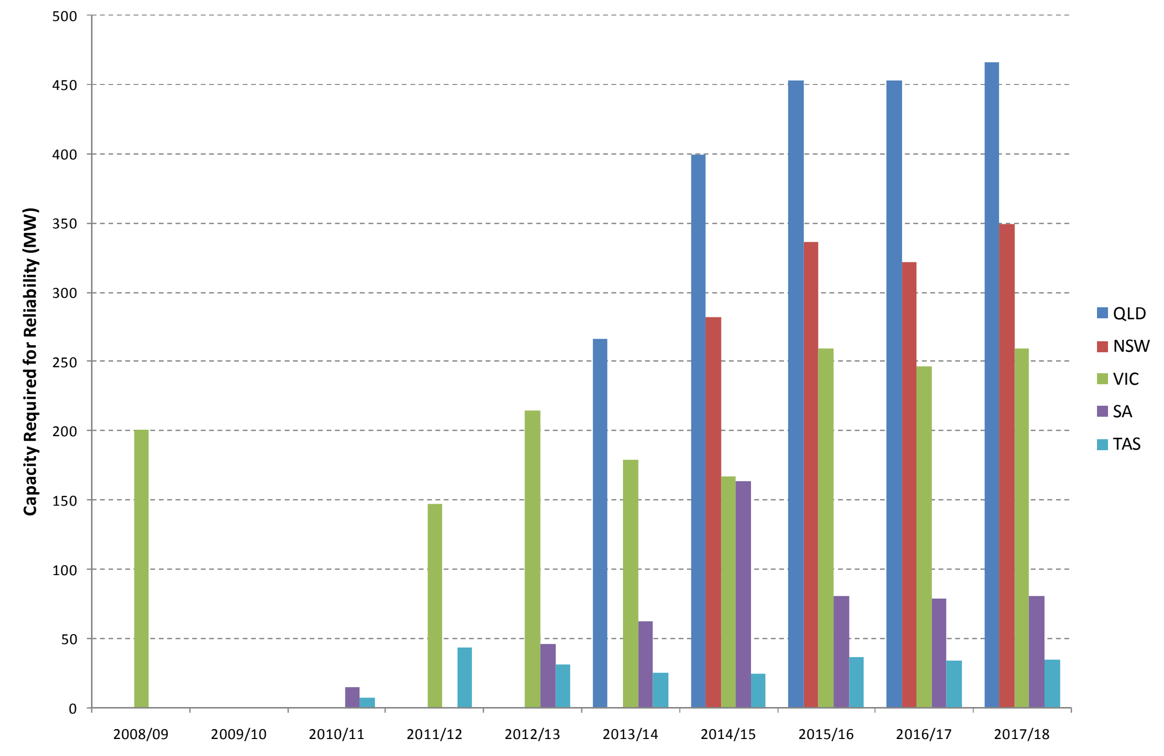
> *The interface between regulated networks and unregulated generators is a critical interface. The behavior of networks should be regulated to be stable, predictable and consistent with efficient outcomes. It should be responsive to the needs of the market, but should not 'crowd out' market investment.*

There is an expectation that the introduction of the RET will drive significant investment in the renewable sector, particularly in strong renewable energy regions, such as South Australia and Victoria. It is typically assumed that the CPRS will also drive investment in renewable generation, although ROAM's and MMA's research suggests that until emissions permit prices reach high levels, the CPRS is unlikely to stimulate substantial renewable investment.

The conventional wisdom is that the CPRS should further stimulate the development of gas fired plant, particularly combined cycle generators which gain competitive advantage over coal generators at higher capacity factors with an increasing carbon price. At very high carbon price levels, traditional coal fired generation will no longer be the lowest cost generator for baseload applications. Offsetting this effect, high future gas prices and demand reduction under the CPRS will reduce investment in gas-fired generation.

The risk of significant gas or renewable resources applying for connection to the grid within a reasonably close timetable is unlikely. Figure 7.14 below shows the projected requirement for new entry capacity per region, as forecast by NEMMCO in the 2008 Statement of Opportunities. The figure shows that in Queensland, where load growth is highest of all NEM regions, an average of 450MW is required per annum from 2015/16. To put that in perspective, of recently installed or committed generators this represents the equivalent of one Braemar open cycle power station, two-thirds of Uranquinty open cycle power station, 4/5 of a Darling Downs combined cycle power station or approximately one Tallawarra combined cycle plant. That is, it would be unlikely for best practice new entrant gas fired thermal plant to apply for connections at the same location in the same year even considering a high load growth region such as Queensland.

Figure 7.14 – New Capacity Required per annum



Transmission development would therefore at most need only serve a single new entrant thermal generator per annum, per region. In renewable-rich regions such as South Australia, Victoria and Tasmania, wind installations primarily, with gas peaking support, could be expected to fill the shortfall in supply in the medium term.

The materiality of potential inefficiencies from new entrants and the 'coordination problem' surrounding connection applications is considered minor. Given the often diverse location of new entrant generators, it would be imprudent to develop a transmission connection significantly greater than required when the surplus capacity may not be required for several years.

As discussed in Section 7.2.3), ROAM's modelling has determined that transmission congestion may significantly curtail the energy exported from renewable-rich locations, such as South Australia. Given that intra-regional and inter-regional transmission congestion will provide a material risk to wind developments in particular, the materiality of inefficient local connection assets is considered low against the requirement to manage the growth of the transmission network necessary to maximise the capacity for the RET to achieve maximum renewable energy uptake. As previously concluded, ROAM's modelling results strongly suggest that significant transmission upgrades to accommodate large exports out of South Australia are required to allow for the maximum development of potential wind generation viable in the region.

8) INTERACTION BETWEEN THE RET AND CPRS

As two distinct schemes, the RET and the CPRS will affect the electricity market in different ways. The impacts of each must be considered individually, but it is important to consider and analyse the interaction between the two schemes. ROAM routinely includes both the RET and the CPRS in modelling scenarios to determine the interaction of the two schemes, as well as performing base-case scenarios to analyse the impacts of each alone.

It is stated in the AEMC scoping paper that the expanded RET will 'magnify' some of the effects of the CPRS. ROAM identifies the issues of significance to be:

- **Interaction of markets:** The interaction of the emissions permit market and the RECs market may be non trivial. This is discussed below.
- **Price volatility:** Both the RET and CPRS are likely to impact upon price volatility in the market. Whether they have complementary or opposing effects on volatility, and what the two schemes might do in combination is discussed in section 11).
- **Transmission congestion:** Both the RET and CPRS are likely to impact upon transmission congestion in the market. Whether they have complementary or opposing effects on congestion, and what the two schemes might do in combination is discussed in section 7).

8.1) INTERACTIONS OF MARKETS

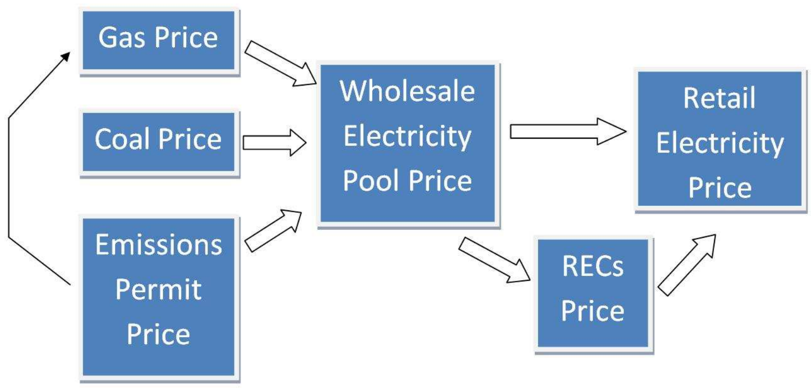
Currently, the electricity market operates with relative independence of other markets, being affected only moderately by the gas price, due to the relatively small proportion of electricity that is generated by gas.

Over the next five year period, this will change dramatically, with the creation or significant scale-up of three markets that will interact strongly with the electricity market.

1. **Carbon permits:** With the introduction of the CPRS a significant new market in carbon permits will emerge, and this market will interact strongly with the electricity market. The vast majority of electricity generated in Australia comes from fossil fuel fired generation; these generators will pass through emissions permit prices into the wholesale electricity pool price and contract prices, which will be passed through to the retail electricity price.
2. **Gas:** Driven by the CPRS, it is anticipated that the proportion of electricity supplied by gas will significantly increase, which will more closely integrate the electricity and gas markets. This is discussed in detail in the following section.
3. **Renewable Energy Certificates:** The Renewable Energy Target will be dramatically increased, expanding the market for Renewable Energy Certificates (RECs). This market will also interact strongly with the electricity market.

The anticipated main interactions between these markets are illustrated in Figure 8.1. The gas price, coal price and price of emissions permits will combine to dictate the short run marginal costs of fossil fuel fired generators. This will influence the bid prices of fossil fuel fired generators, and therefore strongly affect the wholesale electricity pool price.

Figure 8.1 – Market interactions



The emissions permit price may affect the gas price by creating additional demand for gas. If the emissions price is sufficiently high to cause a large increase in gas usage (perhaps due to fuel switching from coal), the increased usage will put upwards pressure on gas prices. However, MMA's modelling for Treasury suggests that gas may play a smaller role under the CPRS than commonly assumed, and ROAM's modelling supports this assertion (as discussed in section 4.6).

Since the Renewable Energy Target (RET) necessitates a percentage of energy to be sourced from renewable generators each year, the price of RECs is expected to increase to the level sufficient to make this occur (within the price cap). This will be the point where the average Long Run Marginal Cost (LRMC) of renewable generators being installed is equal to the sum of the wholesale electricity pool price, and the price of RECs.

$$\text{Price of RECs} = LRMC_{Renewable} - \text{Wholesale electricity pool price}$$

Thus, the price of Renewable Energy Certificates (RECs) is strongly influenced by the wholesale price of electricity. Also, different types of renewable energy have different time of day generation profiles; for example solar generation peaks in the middle of the day, wind generation is relatively constant but peaks in the afternoon, and solar thermal technology can store energy for later generation. This might influence the price of RECs: if solar power plants are able to capture high pool prices with high volumes in the middle of the day, they may be less dependent on RECs as a source of revenue to meet their LRMC than wind farms would be. Thus the mix of renewables also influences the REC price.

Retailers will need to purchase increasing quantities of RECs under the expanded RET, and are expected to pass this increased cost onto consumers. Thus the retail electricity price will be determined by a combination of the wholesale electricity pool price, and the price of RECs.

The relationships pictured in Figure 8.1 show the dominant interactions. Feedback interactions may also occur, although are likely to be much weaker and only apply significantly under extreme circumstances. For example:

- As the retail electricity price rises, demand may reduce, which will reduce the wholesale price of electricity
- If demand reduces sufficiently, this may decrease the price of emissions permits, by lowering the cost of abatement (through use of energy efficiency)
- The gas and coal markets are known to not be entirely independent of each other, since they compete for generation volume in the electricity market.
- Electricity is used in the extraction of coal and gas; with a dramatically increased electricity price, the cost of these commodities may rise. This is considered to be an extremely weak interaction, since the price of coal and gas is dictated more through supply and demand in those markets.

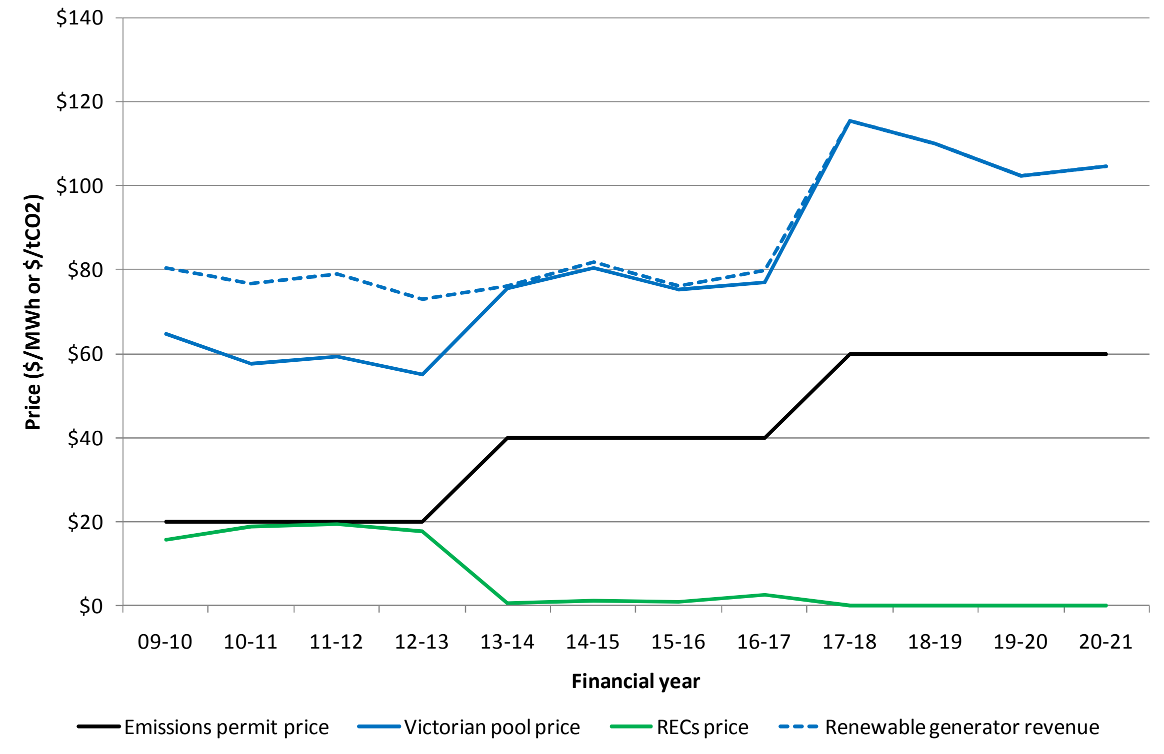
Renewable Energy Certificates

It is stated in the AEMC scoping paper[28] that the RET will make renewable generation more profitable, as will the CPRS (through increased pool prices). However, the combination of the RET and CPRS is unlikely to make renewable generation more profitable than the RET alone, as described below.

Due to the interaction between the electricity pool price and the RECs price, under low carbon prices, renewable generators will remain supported by the Renewable Energy Target scheme. It is expected that as the pool price increases under the CPRS, the price of Renewable Energy Certificates (RECs) will decrease by a corresponding amount, due to competitive sale of the certificates. This means that renewable generators will not experience a net benefit under the CPRS until the carbon price is sufficiently high that the RECs price reaches zero (indicating that the Renewable Energy Target scheme is no longer necessary to support renewable generation). ROAM's modelling indicates that this may occur at a carbon price between $40/t$CO_2$ and $60/t$CO_2$ (as shown in the figure below).

[28] Review of Energy Market Frameworks in light of Climate Change Policies, Scoping Paper, AEMC, 10th October 2008.

Figure 8.2 – Forecast RECs prices (medium load growth)



This figure illustrates that as the carbon price rises over time, the pool price also rises. The RECs price falls in response such that the revenue of renewable generators remains relatively stable until the RECs price reaches zero. At this point, renewable generator revenues increase beyond their LRMCs (approximately $80/MWh for wind farms) and they begin to profit from the CPRS.

Differing Objectives of RET and CPRS

The objective of the Renewable Energy Target is to mandate the introduction of an extra 45,000 GWh of renewable generation by 2020; the objective of the Carbon Pollution Reduction Scheme is to reduce emissions to a defined target on an annual basis. Both objectives are to be achieved at least cost to the economy, but the price of the units is different (effectively $/tCO_2$-e for the CPRS and $/MWh for the REC price to meet the RET). As is commonly pointed out, the RET may not be the lowest cost way of reducing CO_2 emissions, as replacing high-emissions coal plant with lower emission CCS or gas plant may achieve this objective at lower cost. As noted previously, with a CPRS and very high carbon prices, renewables are favoured over any fossil fuel plants, obviating the need for a RET.

ROAM's modelling suggests that increasing the Renewable Energy Target is not an ideal mechanism for reducing greenhouse gas emissions, since increasing renewable generation does not automatically proportionately reduce CO_2-e. ROAM's modelling shows that renewable generation stimulated under the RET tends to displace the least CO_2-e intensive fossil fuelled generation (gas) rather than the most CO_2-e intensive (brown coal).

Despite the fact that in a perfect economic system the RET is not the least cost way of reducing emissions from the electricity sector, it may have other benefits that warrant its inclusion in the post 2010 regime. Renewable energy receives wide public support, and is often considered to have other benefits beyond emissions reduction. Over a longer timeframe, a transition to a low emissions economy is necessary, and beginning the transition early places Australia at the forefront of technology research, development and commercialisation.

While the merits of the RET in combination with the CPRS can be debated at length, it is important to consider the way that they will interact, given that they have different market objectives. This is an area that requires further careful consideration.

Box 14 – Interaction of new and expanded markets
The CPRS and the RET are expected to create or significantly expand markets for emissions permits, gas and RECs. These markets will interact strongly through with the electricity market, potentially with unexpected consequences and subtleties. The conventional wisdom is that renewable technologies will become more competitive under the CPRS. However, whilst renewable technologies remain dependant upon the RET for support, they are unlikely to benefit from the CPRS. Very high emissions permit prices (\$40 to \$60 /tCO_2) will be required for renewable generators to be advantaged by the CPRS beyond the support of the RET. The interaction of the RET and the CPRS is a topic that is poorly understood, and requires substantial further investigation. Unexpected subtle interactions are possible that may skew market outcomes.

9) Western Australia and Northern Territory Electricity Markets

9.1) SWIS, NWIS and Kimberleys

The effects of the CPRS and RET will be similar to those in the NEM, but with the potential to be magnified. The reasons are as follows.

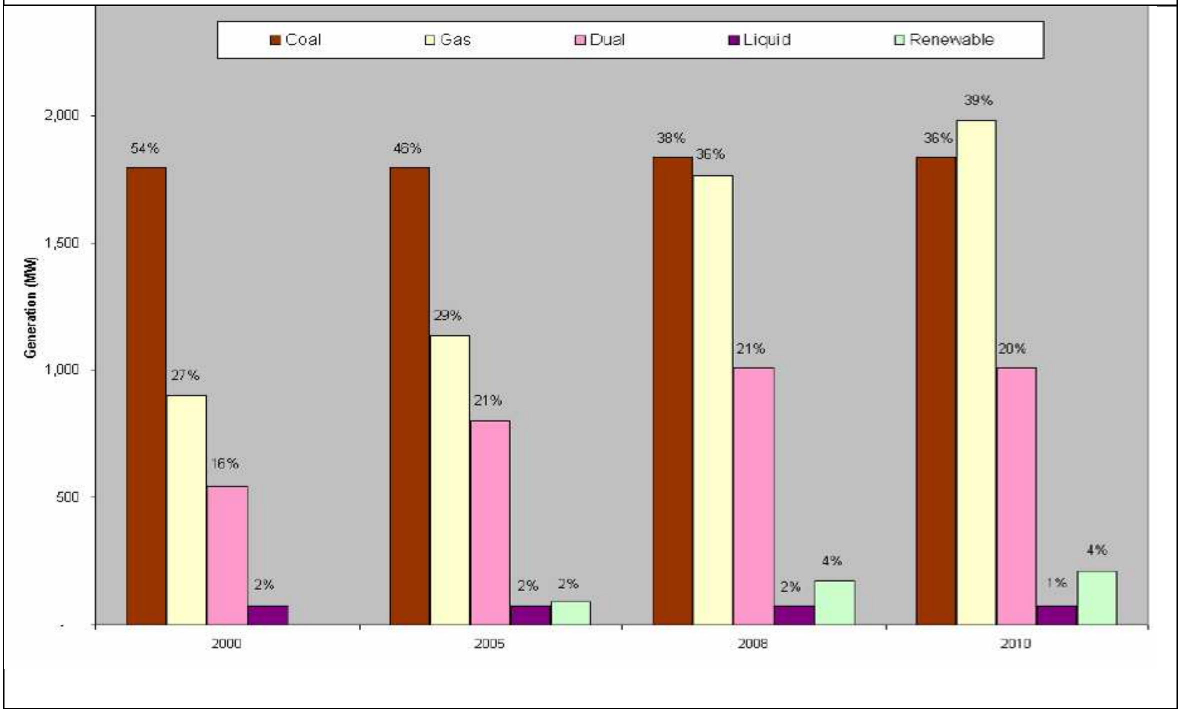
- Because generators in the SWIS have to bid at SRMC, there is no opportunity for generators to modify their bids in order to stay online and avoid decommitment.
- Cycling may occur more often – as generators can't submit a \$-1000 bid as in the NEM, they can always be undercut by the renewables. Fossil fuelled WA power stations will become less competitive over time.
- Transmission – WA has very good wind resources. If large amounts of wind generation go ahead, this will cause challenging transmission issues.

- o The SWIS has an annual Reserve Capacity Auction. The current scheme is that wind farms and other renewables get paid reserve credits equal to their average output. If these renewable stations don't produce average output at time of peak, this is not a "fair" arrangement.

- o There is an annual capacity payment – to make up LRMC cost.

In a presentation to CIGRE in November 2008, Brendan Clarke of Western Power noted that capacity markets (such as the SWIS) have trouble with limited fuel supplies, especially gas supply and transport. A capacity market exacerbates dependence on gas. The percentage of electricity generation in the SWIS from gas fired generators has been increasing from 27% in 2000 to 36% in 2008 and is projected to reach 39% by 2010. See Figure 9.1 (taken from the presentation) below.

Figure 9.1 – Electricity generation profile by fuel type in SWIS



9.2) NT ELECTRICITY MARKET

All operational fossil fuel power stations in the Northern Territory are either gas or distillate[29]. These include major stations such as Channel Island and Weddell in Darwin and Ron Goodin in Alice Springs. Of 613 renewable power stations in Australia, 86 are in the Northern Territory. Solar projects account for 81 of these (1678 kW total), with 4 wind projects (95 kW) and 1 landfill gas station (1100 kW).

[29] Geosciences Australia register of power stations in Australia.

There is little potential for wind generation in the NT[30]. However, most areas of the NT receive an annual average daily solar exposure of more than 24 MJ/m^2, ideal for solar generation.

With the current configuration of power stations, cycling is not a big issue in the Northern Territory as all grid connected stations are either gas or gas/diesel fired.

The Isalink high voltage power transmission project, now under study, contains a proposed extension from Mt Isa to Darwin.[31] This would increase reliability, and effectively absorb the small Northern Territory load into the Queensland system. (The 2007 Power System Review of the Utilities Commission shows a forecast peak demand in 2007-08 of 266 MW for Darwin Katherine system, 55 MW for Alice Springs system, and 7 MW for Tennant Creek system, a total of 328 MW.) The interconnection of the system with Queensland and the rest of the NEM would become more attractive if grid connected renewable generation increased in the NT.

Box 15 – Markets in NT and WA
Due to the different market rules and operation in WA, there is potential for the CPRS and RET to impact more strongly on its operation. In addition, the extensive wind resources in WA combined with the limited grid size are likely to cause transmission congestion due to intermittency. The NT system is unlikely to see significant development in wind, but is likely to instead utilise the excellent solar resources in that region. The solar resources in the NT may provide further incentives for the interconnection of the system with Queensland through Mt Isa.

10) INTERACTION OF THE GAS MARKET AND THE ELECTRICITY MARKET

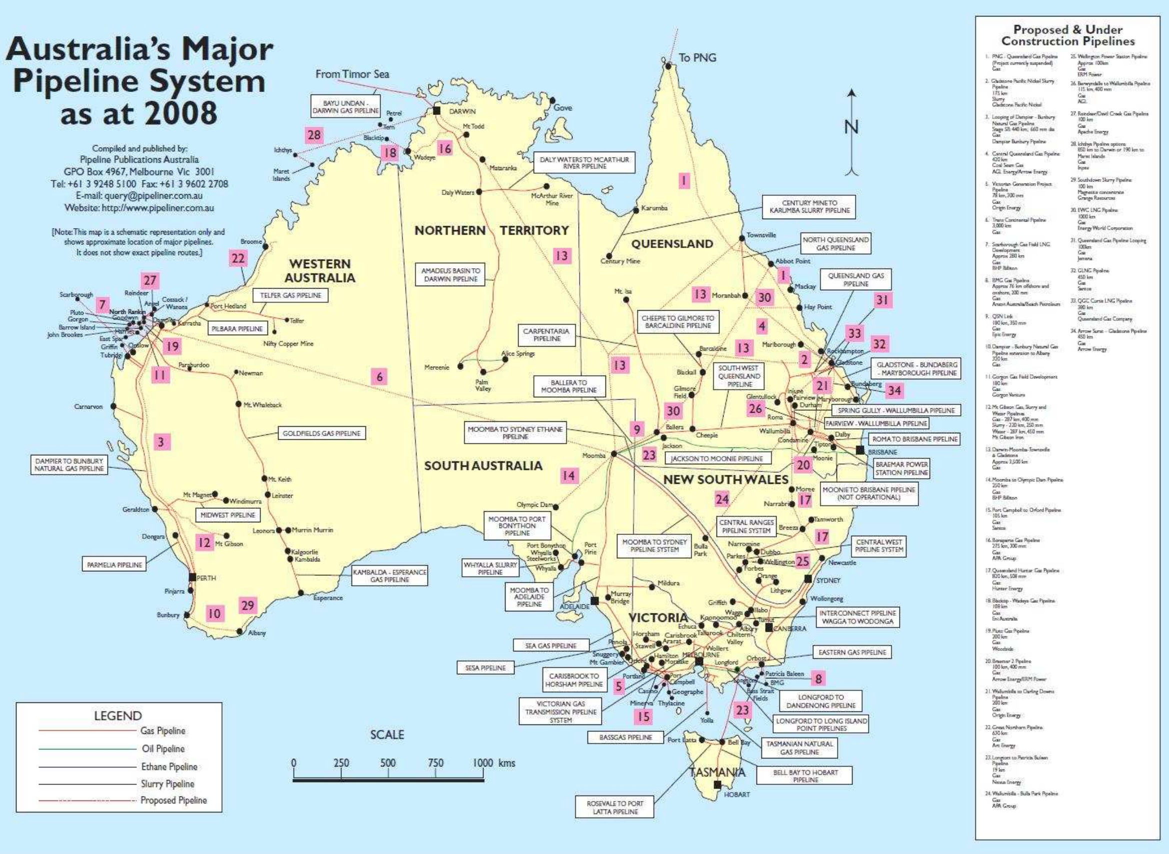
10.1) GAS SUPPLY IN AUSTRALIA

Figure 10.1 shows a map of Australia's gas pipeline system from the 2008 NEMMCO Statement of Opportunities. Compared to the map in the 2007 SOO, there are now 34 proposed and under construction pipelines compared with 22 in the the 2007 SOO. Important hubs in the Australian gas supply network include Moomba in South Australia, Dampier in Western Australia, Longford in Victoria, and Wallumbilla in Queensland.

[30] Renewable Energy Atlas of Australia, http://www.environment.gov.au/settlements/renewable/atlas/pubs/mean-wind-speed.pdf; http://www.environment.gov.au/settlements/renewable/atlas/pubs/daily-solar-exposure.pdf

[31] http://www.cabinet.qld.gov.au/MMS/MediaAttachments/2008/pdf/ISAmap_BT.pdf

Figure 10.1 – Pipeline Publications Australia Map from NEMMCO 2008 SOO



Apart from small quantities of domestically produced coal seam gas, the bulk of New South Wales' gas is supplied from the Cooper Basin gas fields in northern South Australia and south-western Queensland through the Moomba to Sydney pipeline system (MSPS); and from offshore Victoria through the Eastern Gas Pipeline.

Natural gas in Queensland is either coal seam methane or conventional gas. Conventional gas is taken from fields in the Cooper Eromanga Basin, particularly at Ballera and Roma. Coal seam gas reserves are located in the Bowen and Surat basins.

The major production facility for gas in South Australia is at Moomba in the north east of the state, drawing gas from the Cooper Basin. The SEA Gas pipeline connects SA to Victoria, which has many gas fields in the Gippsland and Otway basins, and in the Bass Strait.

10.2) CATASTROPHIC SINGLE POINT FAILURES IN GAS SUPPLY

Historically, gas supply has been prone to catastrophic single point failures, with dramatic consequences. This is a significant concern given the widely held belief that the CPRS will stimulate increased investment in and reliance upon gas-fired generation. The increasingly close integration of the gas and electricity markets under a CPRS may mean that catastrophic single point failures in gas supply translate into decreased reliability in the electricity market.

Offsetting this effect, more gas pipelines are being developed. A short list of proposed pipelines from the Pipeline Publications Australia map follows.

- Wallumbilla to Breeza (Queensland Hunter Gas Pipeline)
- Wallumbilla to Bulla Park
- Wallumbilla to Darling Downs
- Wallumbilla to Berwyndale
- Ichthys Pipeline to Darwin
- Gladstone to Injune
- QGC Curtis LNG pipeline
- Arrow Surat to Gladstone pipeline
- Dampier to Moomba (Trans Continental Pipeline)

Also, the QSN Ballera to Moomba interconnect pipeline which connects SA and Queensland is currently under construction and expected to be completed by December 2008. This will be the first gas pipeline between SA and Queensland.

10.2.1) Historical gas supply failures

Explosions at Longford in 1998, Moomba in 2004, and Varanus Island in 2008 demonstrate that gas outages can be unplanned and have severe effects on gas price and availability. The Longford explosion cut gas supplies to Victoria for two weeks. The Varanus Island explosion reduced gas availability in Western Australia by 30% causing serious supply constraints. Gas pipelines are interconnected and these single points of failure have repercussions throughout the system; if gas and electricity markets were fully integrated this dependence could have disastrous effects in the event of an outage.

As noted previously, capacity markets have trouble with limited fuel supplies, and the Varanus Island incident forced curtailment of a number of gas customers, in turn leading to great pressure on the distillate market. Power stations could not afford to “run out” of distillate and storage facilities were limited at each power station. As the NEM is forecast to become more dependent on gas fired power stations, thus becoming more like the WA market in this respect, similar outcomes would be expected in the event of gas processing plant or pipeline outages. The NEM is more diversified in sources of supply of gas and impacts would be accordingly reduced.

10.3) GAS AVAILABILITY WHEN REQUIRED

In extreme cold weather conditions, residential gas usage substantially increases for heating purposes. Electricity demand also tends to spike, due to an increase in usage of electricity for heating. This means that when gas supplies are most required for electricity production at (gas-fired) peaking plants, pressures in gas pipelines are lowest, and may not be able to supply sufficient fuel for the power stations to operate.

If gas prices are high (for example during cold snaps) some power plants choose to sell their gas contracts instead of using the gas to generate power.

Box 16 – The gas market in Australia
If the CPRS has the effect of increasing Australia's reliance on gas for electricity generation, it is important to consider the implications of greater connectivity between the gas market and the electricity market. Historically, gas supply has been prone to catastrophic single point failures. The increasingly close integration of the gas and electricity markets under a CPRS may mean that catastrophic single point failures in gas supply translate into decreased reliability in the electricity market. Expected increased investment in gas pipelines may offset this effect. Gas availability during high demand (very cold) times may also become a significant issue.

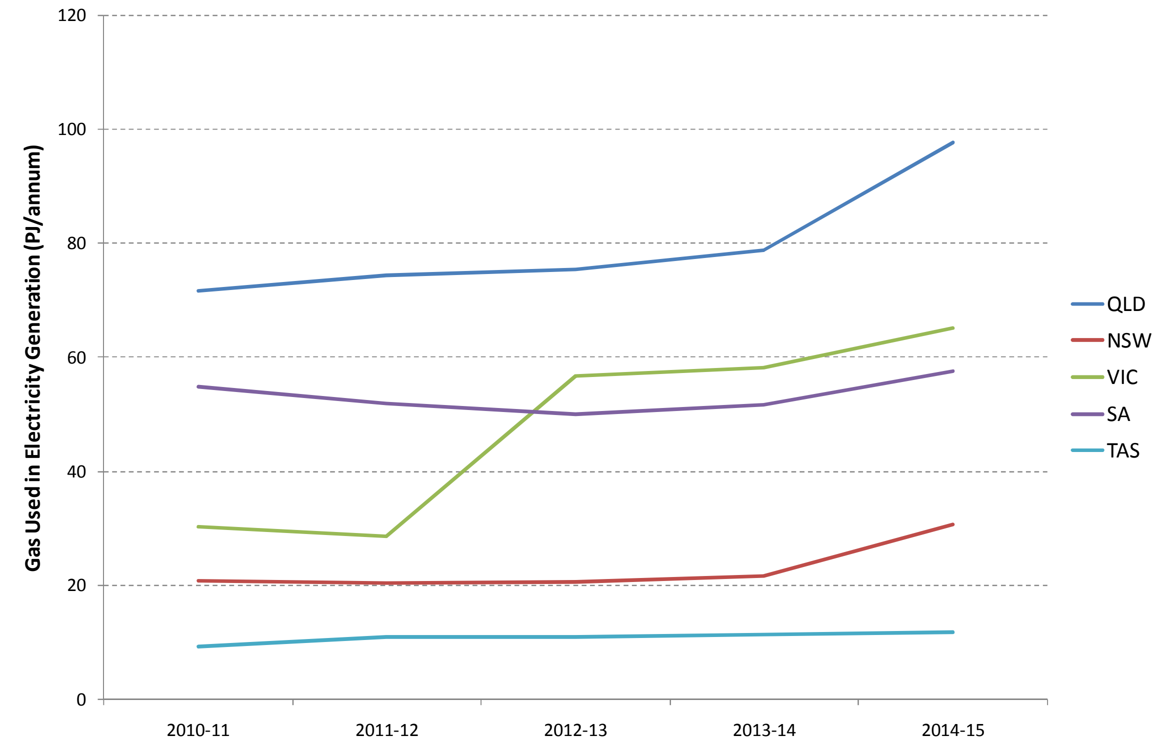
10.4) PROJECTED GAS USAGE

ROAM's modelling gives an indication of potential projected gas usage in the NEM under the RET and CPRS, and suggests when and where periods of high usage might occur. As discussed earlier, there is great uncertainty in the role of gas in the electricity market in the coming decades, so the results here represent a possible projection, under the assumptions modelled.

Figure 10.2 shows ROAM's projection of gas usage in the NEM under the "adverse" case (with a weighting of M10 and M50 demand projections). The "adverse" case uses a higher emissions permit price of $20/t$CO_2$ in 2010, rising to $35/t$CO_2$ in 2015 and lower energy derived from hydro generators. The higher price on emissions will increase the competitiveness of gas fired generation as compared to other stations using higher emitting fuels such as coal plant. This analysis therefore provides a 'high' view to gas utilisation in electricity generation, and would be marginally lower in the "expected" case, with lower emissions prices and increased hydro operation.

In all scenarios modelled here, gas generation increases considerably between 2013 and 2016 in Queensland due to the projected commissioning of large gas fired power stations including Braemar Stage 2, Spring Gully and Swanbank F power stations. Similarly South Australia experiences large increases in the usage of gas due to the projected commissioning of Pelican Point 2 and Mallala (which has been put on hold since this simulation was completed). The 2007/08 usage of gas in South Australia and Tasmania is exceptionally high relative to the 2013 and 2016 years due to the persistence of drought in that year and increased wind generation in these states in the future.

Figure 10.2 – Projected gas usage (by state)[32]



With a significant increase in gas usage, it is likely that there will be upwards pressure on gas prices, inhibiting further development in gas generation. This may be offset by rising emissions permit prices, depending on the relative magnitude of the two.

Figure 10.3 shows projected gas generation as a percentage of the total energy in each of the five NEM regions. In South Australia, the introduction of wind helps to bring down the percentage of energy met by gas generation; note that FY 2007/08 was a particularly dry year for South Australia and Tasmania. The increasing usage of gas in Queensland is consistent with the planned expansion of the GEC scheme from 13% to 18% by 2020[33].

[32] These results assume an M10 demand (medium growth, 10% probability of exceedance) as defined by NEMMCO in the 2007/08 SOO.

[33] It is currently uncertain whether the Queensland GEC scheme will continue under the CPRS.

Figure 10.3 – Projected gas generation as a percentage of state energy usage

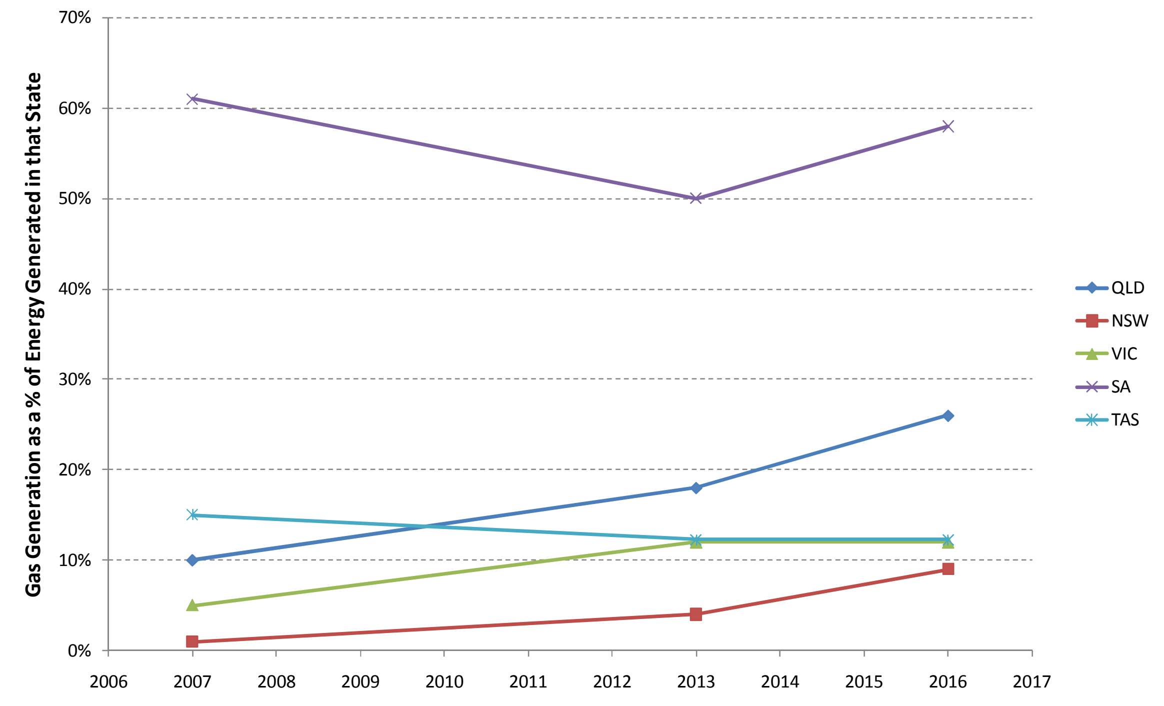
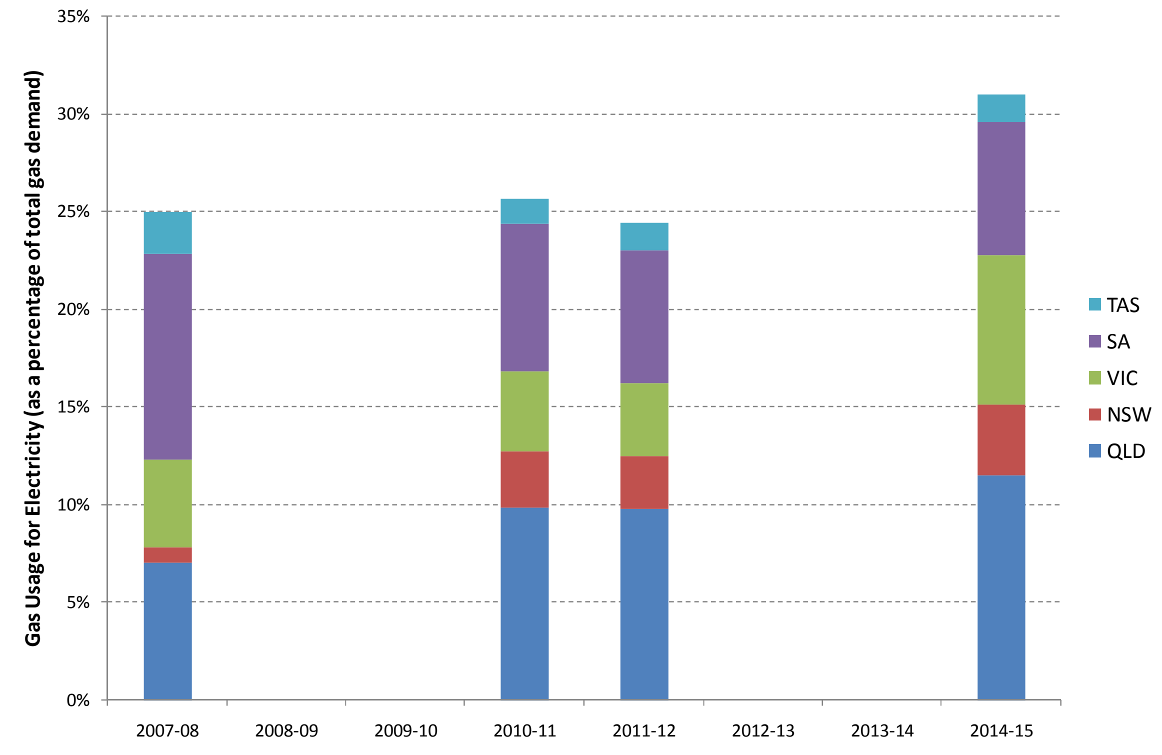


Figure 10.4 below shows projected gas usage in electricity generation as a percentage of the total gas demand in the NEM states[34]. As the figure shows, gas usage is expected to increase in line with general trends in gas usage in the early years of the CPRS, with gas usage for electricity generation holding relatively steady at 25% of total gas demand. By 2014-15, when the price on emissions permits rises to \$35/t CO_2-e, the share of gas generation increases, which ensures an increase in the share of total gas demand used by electricity generation. Victorian gas fired generators in particular increase their usage, as more generation from combined cycle plant in that region offsets the loss of production from high emitting brown coal generators.

[34] Total Gas Demand taken from Australian Bureau of Agricultural and Resource Economics, 2007, *Australian Energy: National and State Projections to 2029-30* (Research Report 07.24)

Figure 10.4 – Projected gas usage in electricity generation as a percentage of total NEM gas demand



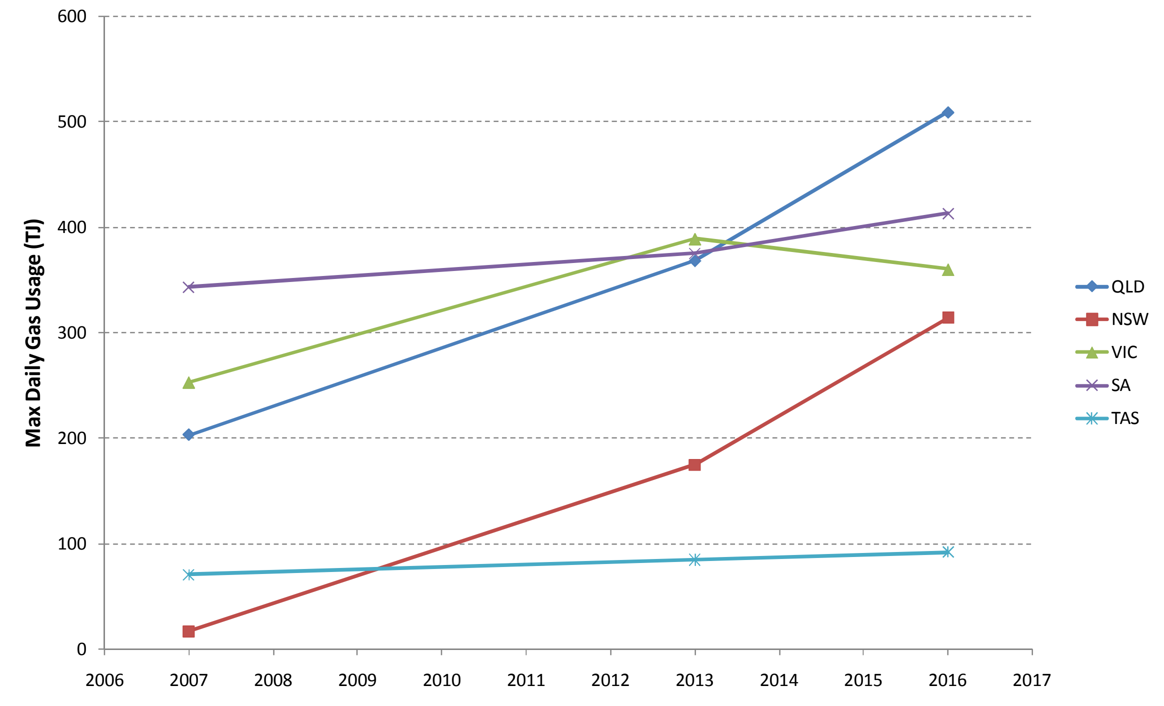
10.5) GAS DELIVERY LIMITATIONS

With a significantly increased usage of gas, there may be limitations in the capacity of pipelines to deliver sufficient volumes. To analyse this, it is necessary to consider the maximum gas usage in a daily period, or on a half hourly period.

Figure 10.5 shows the projected maximum daily gas usage for each of the states. According to a March 2007 report by J L Craddock and Associates for ROAM, the Moomba to Sydney pipeline has a total capacity of 470 TJ/day and a current available capacity of 220 TJ/day[35]. The EGP has a total capacity of 200 TJ/day and an available capacity of between 49 and 137 TJ per day depending on additional compression being installed. Thus, there is sufficient capacity on the Moomba to Sydney pipeline and EGP to meet the projected daily gas usage in 2013 in NSW, but the daily usage in 2016 may require additional compression.

[35] According to Australian Competition and Consumer Commission Moomba to Sydney Pipeline System volume papers.

Figure 10.5 – Projected maximum daily gas usage (TJ) at NEM Power Stations (M10 adverse case)



Of all NEM regions, the most likely to come under supply difficulties is New South Wales. Apart from small quantities of domestically produced coal seam methane gas, the majority of New South Wales' gas is supplied from the Cooper Basin gas fields in northern South Australia and south-western Queensland through the Moomba to Sydney pipeline system (MSPS); and from offshore Victoria through the Eastern Gas Pipeline(EGP). The other states have domestic gas production facilities which meet or exceed their local supply requirements, and therefore are not reliant upon gas imports.

ROAM's modelling shows that the periods of highest combined generation occur in May to June, at periods of high demand in the early evening (17:00 to 19:00).

Box 17 – Projected gas usage and delivery limitations
Although projected gas usage is highly uncertain, there is a possibility that the CPRS will drive significantly increased investment in gas generation. This may cause gas delivery problems, if the pipeline infrastructure is not capable of meeting daily and half hourly periods of peak gas demand.

10.6) GAS PIPELINE VERSUS ELECTRICITY TRANSMISSION DEVELOPMENT

The AEMC have noted that the development of the gas and electricity networks may become 'skewed' due to differences in connection regimes between the gas and electricity sectors.

The disjoint between gas and electricity regulation creates opportunity for gas developers rather than transmission providers. Electricity transmission networks are regulated assets, which neither allow nor charge generators or customers to reserve exclusive transmission access, nor do they negotiate on usage charges. The networks do have a 'user pays' cost structure, where the transmission use of system (TUOS) charges allows TNSPs to gain a regulated rate of return on network assets. A significant test for economic efficiency (the Regulatory Test) needs to be satisfied before approval can be given. This is not the case with the privately owned and developed gas network where gas pipeline development is driven by commercial objectives.

The risks associated with an expanding gas network rather than transmission are relatively low. By delivering gas to load centres or points of transmission strength, electrical losses may be minimised, at the expense of increased auxiliary loads associated with the operation of gas compressors along the pipeline route. The delivery of gas provides an opportunity to strengthen the core of the transmission network, rather than expanding the network to distant gas hubs with very little load, and therefore has the capacity to alleviate transmission congestion by diversifying the generation portfolio.

The recent announcement of the Queensland to Hunter Gas Pipeline , from the Surat basin to Newcastle, shows that gas network expansion has significantly less impediments than transmission development. As identified previously, 12 additional pipeline projects have been proposed, committed to, or commenced construction since the release of the 2007 Statement of Opportunities. This represents a considerable schedule of capital works.

Gas network developers require only sufficient foundation customers to sufficiently minimise capital risk. The development of the proposed PNG gas pipeline, proposed to connect the gasfields in Papua New Guinea to the existing gas networks of the NEM in North Queensland eventually failed due to the inability of the proponents to secure gas supply contracts for the annual delivery capacity. A lack of regulation allows for a risk of over-development, which may then interfere with the development of the electricity transmission network.

The AER Regulatory Test provides a significant barrier to transmission development in its current form by ensuring economic efficiency. That is, the test requires that transmission development provides a net market benefit to electricity suppliers and consumers, by reducing costs associated with fuel, transmission losses, unserved energy, and through increased competition amongst generators among other allowable market benefits. In practice, the test has been difficult to pass on the grounds of 'market benefits' (i.e. where a transmission line is not required to ensure system reliability), as generation often enters the market in time to defer the benefits which would otherwise be attributable to a transmission development. The trade off between regulated transmission development and generation development rarely falls in the favour of transmission. By increasing the availability of gas to areas where gas supply is limited, the effect will be to provide further opportunities for generators to take advantage of transmission shortcomings and delay otherwise necessary transmission development.

The proposed upgrade of the QNI is a good example of the difficulty to successfully apply the Regulatory Test. The QLD and NSW TNSPs (Powerlink and TransGrid) have proposed the upgrade of the Queensland – New South Wales Interconnector (QNI), increasing the transmission network up to 400MW bi-directionally through capital works to the northern New South Wales transmission network. The TNSPs concluded however that the optimum timing of the development was not until 2015-16, and that it would be premature at this stage to commit to the development. The commitment of the Uranquinty, Colongra and Tallawarra gas fired generators in New South Wales effectively shut out sufficient market benefits from accruing to the transmission development. The failure to satisfy the Regulatory Test with this substantial transmission inter-connector development demonstrates the difficult regulatory hurdles that obstruct market-derived transmission developments.

The introduction of the CPRS should however add additional market benefits for transmission development. By having a price for emissions, transmission should accrue benefits for expanding the capacity for low-emission energy reaching the market. Furthermore, an emissions price will increase the value of those benefits derived through savings in transmission losses.

The reliability limb of the Regulatory Test allows for least cost developments which ensure system reliability. In south west Queensland, intra-regional transmission congestion between the generation hub at Braemar and the load centre in the south-east corner of the State threatens the reliable operation of the network. As such, and due to the increasing demand for generation around the natural gas and coal seam methane gas fields of the Surat Basin, the expansion of the Braemar node is commencing having satisfied the AER Regulatory Test (reliability limb) as part of the requirement to expand network capacity between Tarong and Braemar. Although the system reliability requires transmission expansion in this instance, it is unlikely that renewable resources and increased gas generation will provide sufficient stimulus to strengthen the transmission network elsewhere on the grid on reliability grounds.

Box 18 – Gas pipeline vs electricity transmission development
The disjoint between gas and electricity regulation creates opportunity for gas developers rather than transmission providers. In addition, the risks associated with an expanding gas network rather than transmission are relatively low. The introduction of the CPRS should however add additional market benefits for transmission development. By having a price for emissions, transmission should accrue benefits for expanding the capacity for low-emission energy reaching the market. Furthermore, an emissions price will increase the value of those benefits derived through savings in transmission losses. Although an expanded gas network may encroach upon transmission development, the diversification of the generator portfolio should reduce the impact of transmission failures and transmission congestion. Furthermore, the effect of catastrophic single point failures along gas pipelines will reduce with an expanded gas network. Pipeline development is therefore not considered to be a significant risk to the stability of the transmission network, so long as sufficient transmission developments can proceed to strengthen the transmission backbone. The RET and the CPRS may be in potential conflict as the RET is likely to need electricity transmission to support renewables, whereas the CPRS scheme is likely to need expanded gas pipeline development to support expanded use of gas.

10.7) FUTURE GAS PRICES

Gas prices will have a significant impact upon new investment decisions, and upon the functioning of the market. If gas prices rise sufficiently, the CPRS will be inadequate to drive investment towards intermediate and baseload gas technologies. Future gas prices are therefore an essential consideration. ROAM's Integrated Resource Planning modelling reveals that least-cost outcomes are heavily dependent upon the future gas price, highlighting the significance of uncertainty in this area.

There is great uncertainty regarding future gas prices, related to uncertainty over the development of a LNG export industry, driving domestic gas prices towards parity with international prices.

NIEIR's report to NEMMCO[36] emphasises the significance of gas pricing:

> *Note that the estimates for [short and long run marginal costs of] existing and new gas plants depend on the price at which gas can be sourced (there are low and high views on future gas prices). Also for new gas plants the capital costs are escalating as demand for gas turbines increases globally (new coal plants are subject to cost pressures but not to the same extent as new gas plants).*

[36] Climate change policies: international and Australian trends and impacts on the National Electricity Market. Report prepared for the National Electricity Market Management Company (NEMMCO) by the National Institute of Economic and Industry Research (NIEIR), June 2008.

The dependency of the impacts of the CPRS upon the gas price are also commented upon:

> *At $60/t CO2e it is evident that only CCGTs can cover their long run costs at the estimated electricity prices unless CCS (at the probably conservative estimated CCS costs) is applied to coal generators. However, at higher gas prices CCGTs might not be profitable (new entrants are very unlikely to be compensated).*

10.7.1) Gas prices forecast by other parties

A review of the gas prices forecast by other parties provides some estimate of the range of gas prices that are currently anticipated. Figure 10.6 shows the gas price assumptions for the studies reviewed in the Business Council of Australia report[37] (ACIL Tasman[38] and CRA models[39]), and by MMA in their study for the Federal Treasury[40]. ACIL Tasman's gas price assumptions are based on analysis of supply and demand curves for gas.

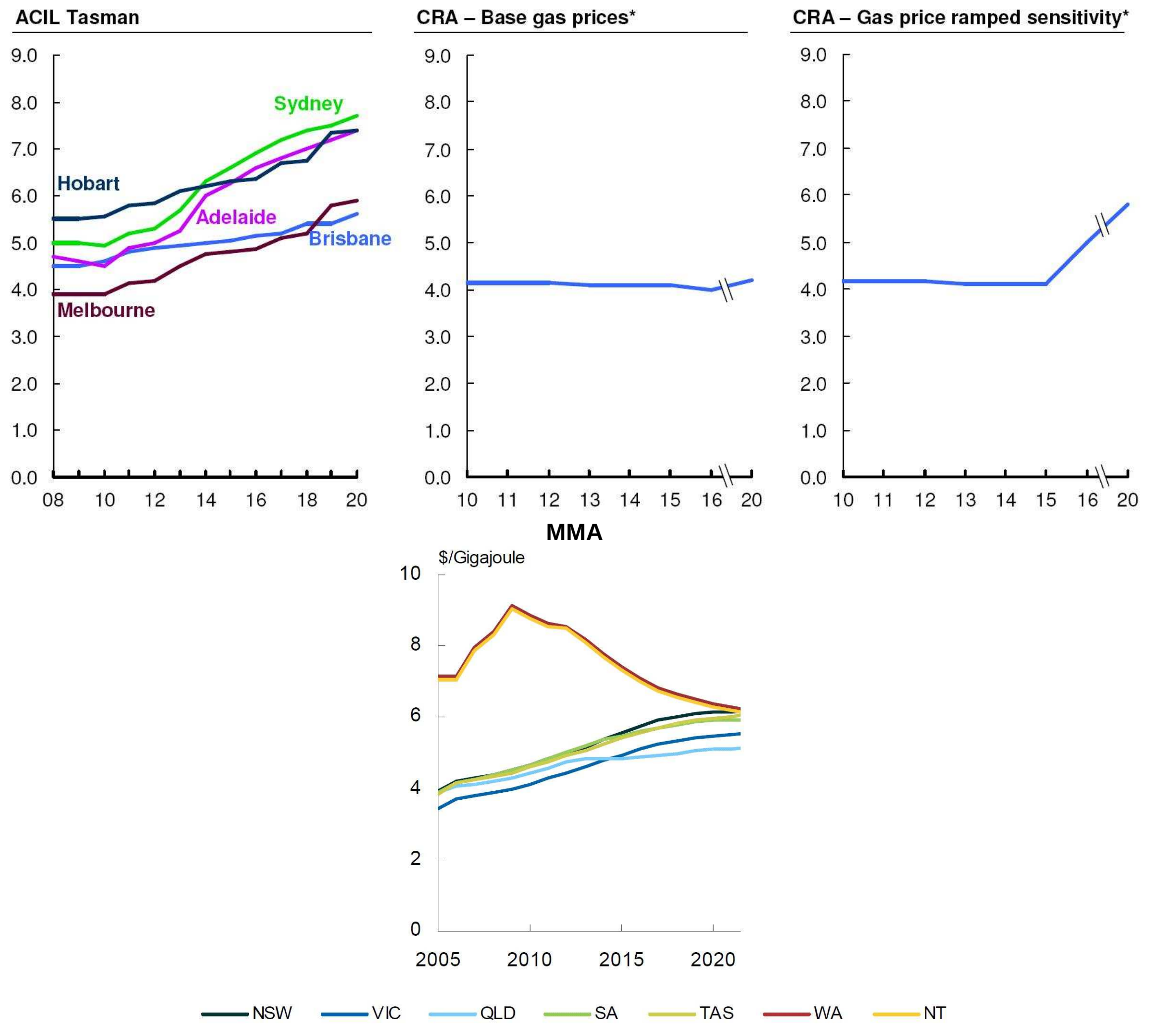
[37] Bringing specific company economic perspectives to bear on the ETS design. Report prepared for the Business Council of Australia by Port Jackson Partners Limited, 21 August 2008.

[38] ACIL Tasman, prepared for the Energy Supply Association of Australia (June 2008), The impact of an ETS on the energy supply industry.

[39] CRA International, prepared for the National Generators Forum (May 2008), Market modelling to assess generator revenue impact of alternative GHG policies.

[40] Australia's Low Pollution Future; The economics of climate change. Federal Treasury, October 2008.

Figure 10.6 – Projected gas prices (review)[41]



To develop gas price projections, MMA combined Australian energy price assumptions with electricity industry specific information to determine the fuel prices faced by Australian electricity generators. The MMA approach was as follows:

- South eastern gas supplies are assumed to be gradually depleted over the next two decades, with gas increasingly sourced from Queensland resources. In addition, LNG facilities are assumed to be developed in Queensland, with a moderate degree of LNG penetration assumptions, reaching 10 Mtpa LNG capacity. As a consequence, east coast gas prices are assumed to converge to international gas prices in 2029-30. Differences in gas transmission costs amongst states, reflecting distance from fuel sources, mean that fuel prices are not equalised across states.

[41] Bringing specific company economic perspectives to bear on the ETS design. Report prepared for the Business Council of Australia by Port Jackson Partners Limited, 21 August 2008.

- Domestic average gas prices were modelled by assuming that gas contracts turnover at a rate of 10 per cent of contracts per annum and that new contracts are influenced by world prices.

Similar, although not identical gas prices were used as an input to Garnaut Review modelling[42]. The chart in Figure 10.6 differs from the chart released as Treasury modelling for the Garnaut review entitled "Climate change mitigation policy modelling – summary of assumptions and data sources". The reason for the difference is not apparent from a comparison of the reports.

Box 19 – Gas price assumptions
If gas prices rise sufficiently, the CPRS will be inadequate to drive investment towards intermediate and baseload gas technologies. Future gas prices are therefore an essential consideration. There is great uncertainty regarding future gas prices, related to uncertainty over the development of a LNG export industry, driving domestic gas prices towards parity with international prices. Projected gas prices in other studies for 2020 range between \$4/GJ -8\$/GJ. Prices in this range will have widely different consequences for the operation of the electricity market under the CPRS.

11) PRICE VOLATILITY

Assessing impacts on price volatility is a significant factor for understanding and analysing the risks that generators, retailers and large customers will face in the market.

Questions of interest to the AEMC include:

- What will happen to the distribution of prices by region?
- How much volatility in the market is accounted for by SRMC based bidding and how much by something else?
- What is the economic cost of dealing with each connection in isolation as opposed to a group at once?

Measure of volatility

A commonly used measure of measure of volatility is the fluctuation in prices over a given time period, typically hourly (as we have used in this report) although trans-day or trans-week fluctuations can also be considered. For example, Zareipour, Bhattacharya, Canizares (2007) considered measures of electricity market price volatility[43] for the case of the Ontario electricity market. Using the methodology applied in this paper, ROAM considered the price volatility of modelling outcomes.

---

[42] P.17, Economic Modelling Technical Paper 3, Assumptions and Data Sources. October 2008. Garnaut Climate Change Review.

[43] "Electricity market price volatility: The case of Ontario", Energy Policy 35 (2007), 4739--4748

The daily volatility $\sigma(d)$, based on the 48 half hourly periods, is given by the standard deviation of the hourly price returns

$$\sigma(d)=\sqrt{\frac{\sum_{t=1+48\times(d-1)}^{48\times d}(r_t-\bar{r}_t)^2}{47}}$$

where r_t is the logarithmic hourly price return for a given time *t*,

$$r_t=\ln\left(\frac{\text{price(t)}}{\text{price(t - 1 hour)}}\right)$$

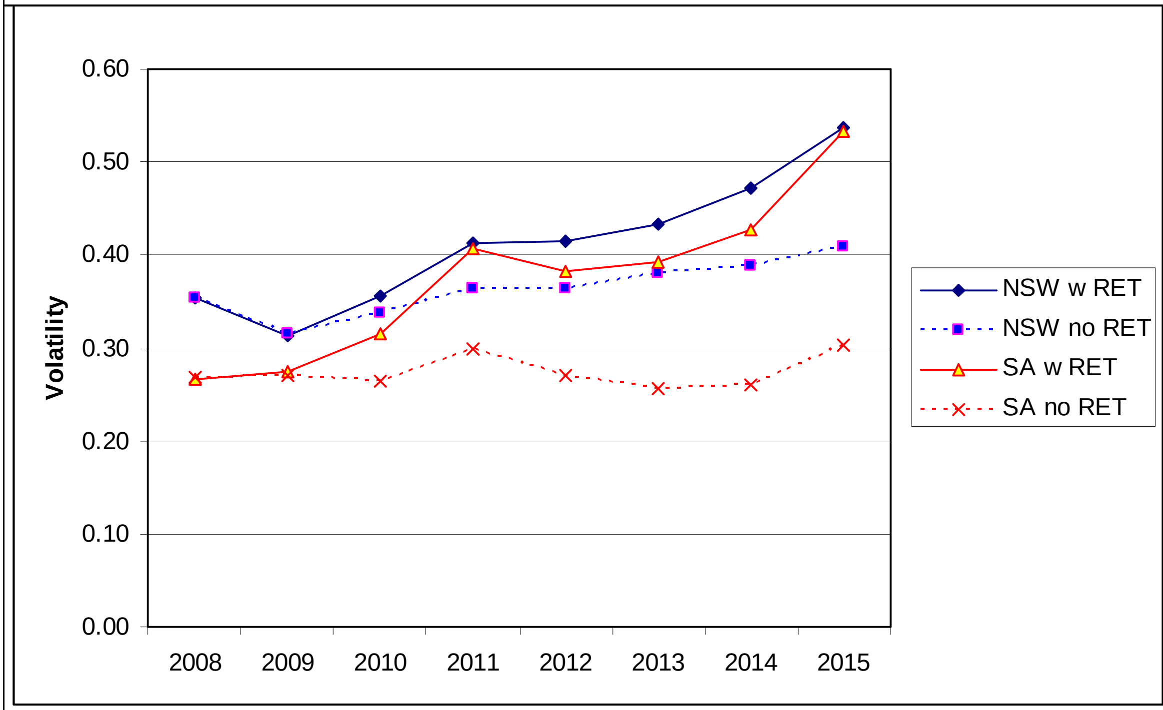
The yearly volatility is defined as the average daily volatility over a financial year. Calculating volatility on individual days minimises errors from expected periodic trends (e.g., seasonal variations).

Impact of the RET upon volatility

The simulations considered both the presence and absence of the expanded RET and included both SRMC based bidding and existing (strategic) bidding. These scenarios included explicit half hourly modeling of wind farm output based on wind trace data obtained from the Bureau of Meterology, as well as traces of daily output of solar generators.

Under historical bidding conditions, the presence of a RET increases the volatility of the pool price, as demonstrated for the NSW and SA markets in Figure 11.1 (other regions follow a similar pattern.) The RET case and the base case initially show very similar levels of volatility (because renewable generation has not yet entered the market in significant levels). As the amount of renewable generation increases under the RET, volatility in the RET case increases beyond that in the reference case.

Figure 11.1 – Effect of RET on volatility of market prices

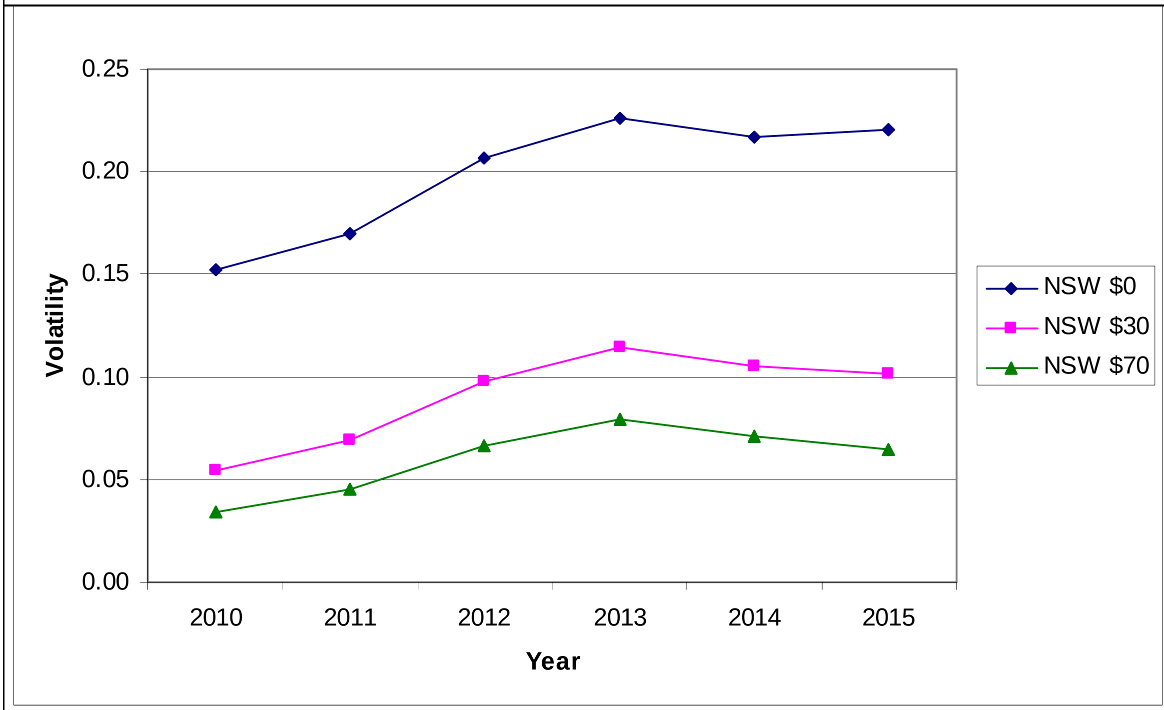


Impact of the CPRS on volatility

Pricing outcomes under the CPRS are heavily dependent upon a number of factors, including the ability of generators to bid strategically. With higher levels of emissions pricing, it is expected that high emissions plant will be forced to bid closer to their short run marginal costs to maintain generation volumes. ROAM has investigated the impacts of different generator bidding strategies upon pricing outcomes, including the extremes of continued historical bidding patterns, compared with pure short run marginal cost bidding.

When the CPRS is applied to the electricity market with SRMC bidding conditions, volatility is reduced, as illustrated in Figure 11.2. For clarity, only the NSW market is shown; other regions follow a similar pattern. This is because SRMC bidding flattens the pool price by time of day, and removes extreme price spikes. With greater levels of strategic bidding (likely to be possible under the expected emissions permit prices in the early years of the CPRS) higher volatility may be expected.

Figure 11.2 – Volatility for NSW market price[44]



Box 20 – Impacts of the CPRS and RET upon price volatility
As would be intuitively expected, the RET increases price volatility. This is due to the entry of large quantities of intermittent wind generation. The impact of the CPRS upon pricing outcomes is more difficult to asses, due to uncertainty over the amount of market power that generators may hold under varying levels of carbon price. At the extreme where generators are forced to bid close to their short run marginal costs, price volatility is significantly reduced under the CPRS.

12) IMPACTS OF CPRS AND RET ON GENERATION BY TYPE

The intention of the CPRS is that plants will be impacted line with their emissions intensities, with high emissions plant tending to back off from generation and lower emissions plant taking their place. ROAM's modelling reveals that while this is broadly the case, the imperfect nature of the transmission system will 'protect' some plant from the full effects of the CPRS, with transmission congestion preventing the full utilisation of less emissions intensive plant. The potential for rising gas prices will also reduce the effectiveness of potential fuel switching.

[44] M10 case (medium demand growth, with 10% probability of exceedance peak demand) with SRMC bidding

Box 21 – Impact of CPRS on Dispatch Merit Order
The trading strategies of existing generators will be significantly tested by the introduction of the CPRS, especially when the price for emissions permits rises to high levels. With a \$35/t CO_2-e emissions price, the merit order of combined cycle plant and brown coal may switch, if plant are bid to ensure that they run only when the spot price meets or exceeds the short run marginal cost. For example, a typical new entrant combined cycle plant should have a short run marginal cost in the order of \$40/MWh. On the other hand, Hazelwood power station, the most emissions intensive plant in the NEM, will be severely impacted by a high carbon price. Hazelwood has an emissions intensity above 1.0t/MWh, which may push its short run marginal cost up above \$50/MWh with a \$35/t CO_2-e emissions price.

This section describes results from a typical study by ROAM, demonstrating the impact of the CPRS and RET on representative gas and coal generators. The results from two cases are presented:

- **Expected Case:** Historical average utilisation of hydro generators at Snowy and Tasmania. The expected case has an emissions permit price rising from \$13.50/tCO_2 in 2010 to \$20/tCO_2 by 2015.
- **Adverse Case:** 'Drought affected' utilisation of hydro generators at Snowy and Tasmania, lowering annual energy considerably from historical averages. The adverse case has an emissions permit price rising from \$20/tCO_2 in 2010 to \$35/tCO_2 by 2015.

The results also incorporate two demand forecasts:

- M10 – medium economic growth with 10% probability of exceedence demands
- M50 – medium economic growth with 50% probability of exceedence demands.

The representative generators analysed are:

- Brown coal:
  - **Hazelwood** is an existing 1,600 MW brown coal plant in Victoria.
- CCGTs:
  - **Tallawarra** is a planned 400 MW CCGT development of TruEnergy in NSW which is registered in the NEM as of 16 October 2008 and currently in the testing stage.
  - **Swanbank E** is an existing 385 MW CCGT of CS Energy in Queensland.
  - **Pelican Point** is an existing 450 MW CCGT of International Power in SA, supplying 25% of SA's current needs according to its website.[45]
- OCGTs:
  - **Uranquinty** is a planned 640 MW OCGT development of Origin Energy in NSW with commercial operations beginning in late 2008.
  - **Braemar** is an existing 450 MW OCGT of ERM Power in Queensland.

[45] http://www.ipplc.com.au/Page.php?iPageID=33

12.1) BROWN COAL (BASELOAD PLANT)

ROAM's modelling shows that CPRS and expanded RET will have the expected pronounced effect on the highest emissions brown coal power stations such as Hazelwood.

Figure 12.1 and Figure 12.2 compare the generation duration curves for Hazelwood in the projected years 2013 and 2016. In 2013 Hazelwood maintains minimum load 100% of the time, but if Hazelwood is still operational in 2016, with historical bids it is predicted to shut down completely for 10% of the time in the M10 adverse case. This means that the generator is no longer capable of maintaining at least minimum load throughout all periods of the year, should it's operating strategy attempt to pass on the costs associated with emissions permits to customers. However, Hazelwood may be able to change their bidding strategy under the CPRS to maintain generation volumes.

Figure 12.1 – Hazelwood Generation Duration in 2013 for four cases

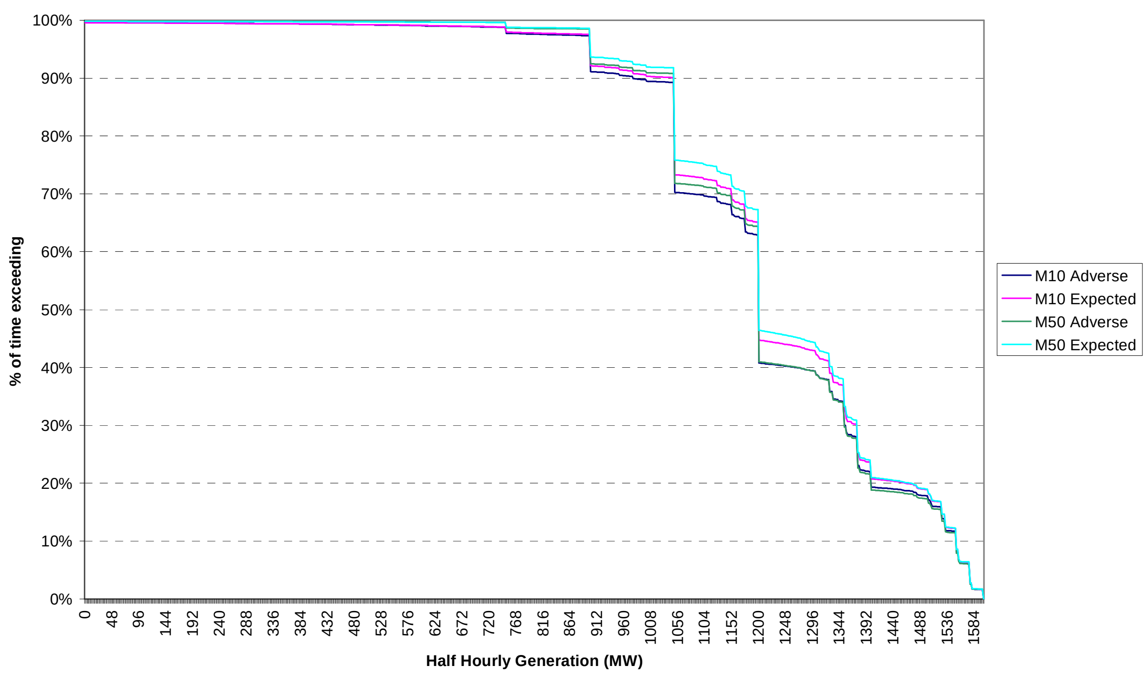


Figure 12.2 – Hazelwood Generation Duration in 2016 for four cases

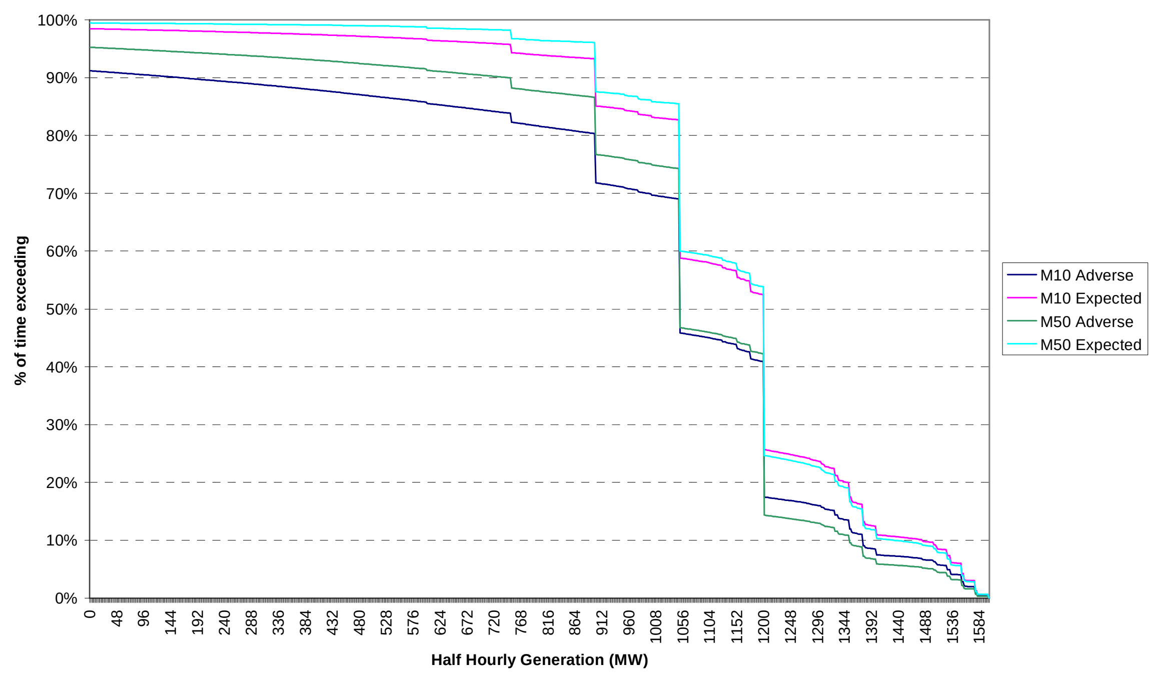


Figure 12.3 shows that Hazelwood's average dispatch remains between 1000 and 1400 MW at all times in 2013 in the four cases. However, with the higher carbon prices implemented in 2016 (refer to Figure 12.4), average generation falls below 500 MW in the M10 adverse case in the early morning off-peak hours. This average includes many periods where the station was completely shut down, indicating that Hazelwood may need to become more flexible in it's operation, allowing overnight cycling, in order to remain operational. Due to the expense of cycling a coal-fired generator, Hazelwood may instead choose to shut down completely for the majority of the year, and only operate during the higher priced summer months.

Figure 12.3 – Hazelwood Time of Day Generation in 2013 for four cases

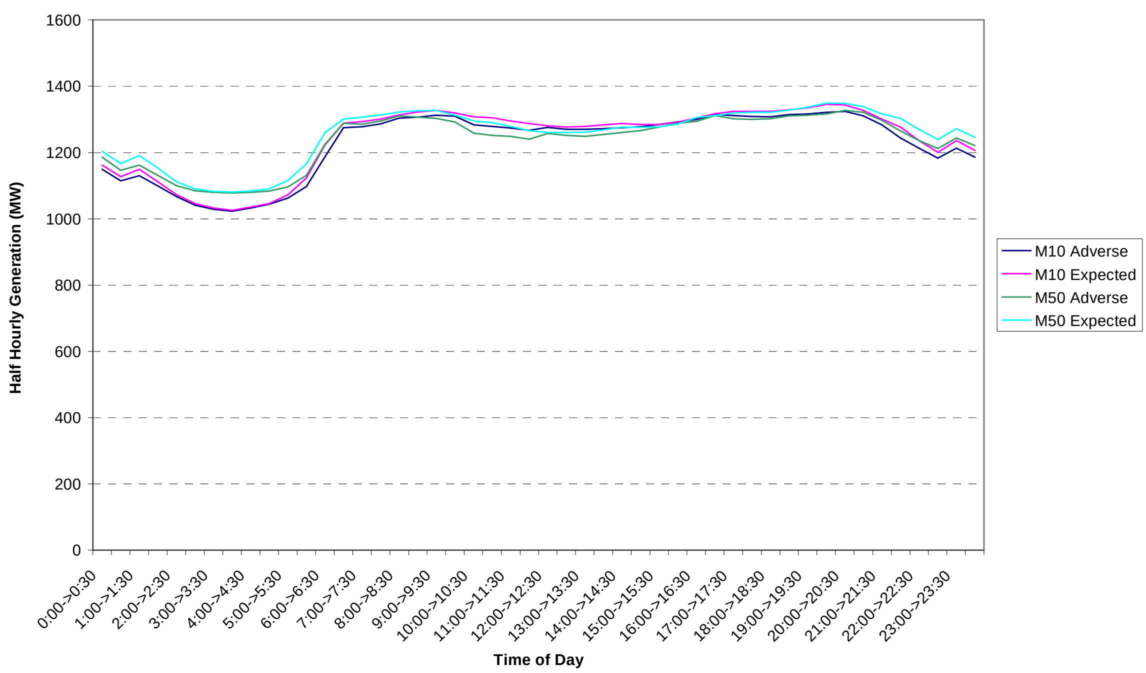
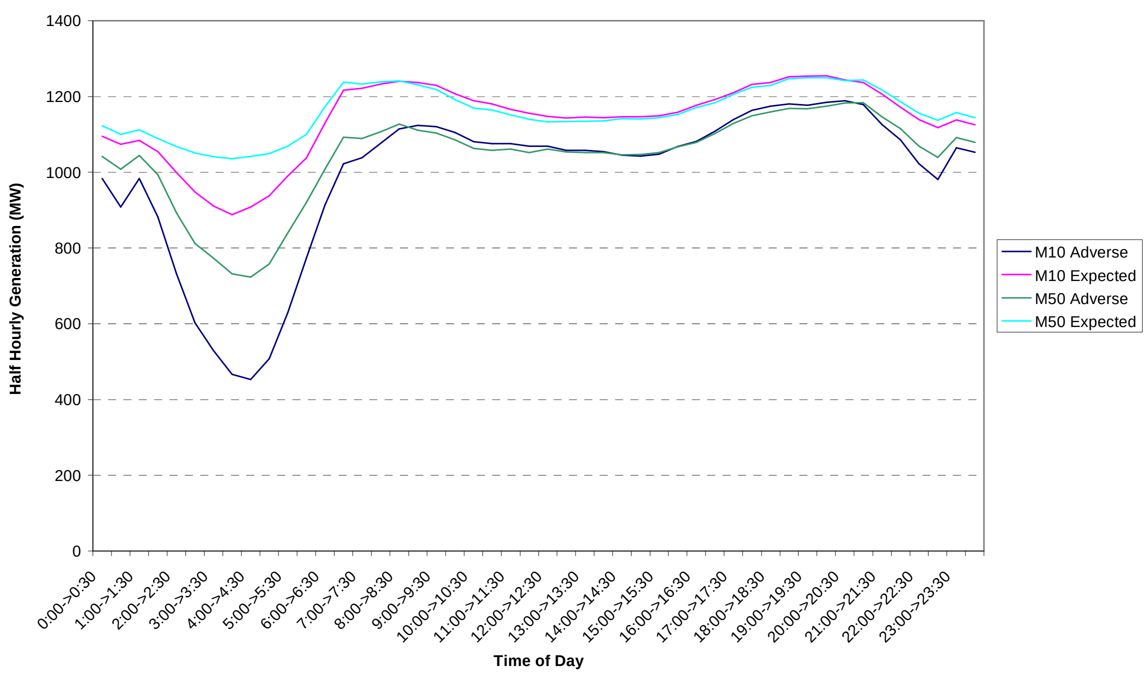


Figure 12.4 – Hazelwood Time of Day Generation in 2016 for four cases



The following chapter includes a much more detailed analysis of the profitability of coal-fired generation under the CPRS.

12.2) CCGT'S (INTERMEDIATE PLANT)

Figure 12.5 and Figure 12.6 show the average time of day generation of Tallawarra combined cycle gas power station in 2013 and 2016. Generation increases in both on-peak and off-peak periods in the presence of high carbon prices, as would be expected with higher emissions coal-fired plant reducing generation volumes.

Figure 12.5 – Tallawarra Time of Day Generation in 2013 for four cases

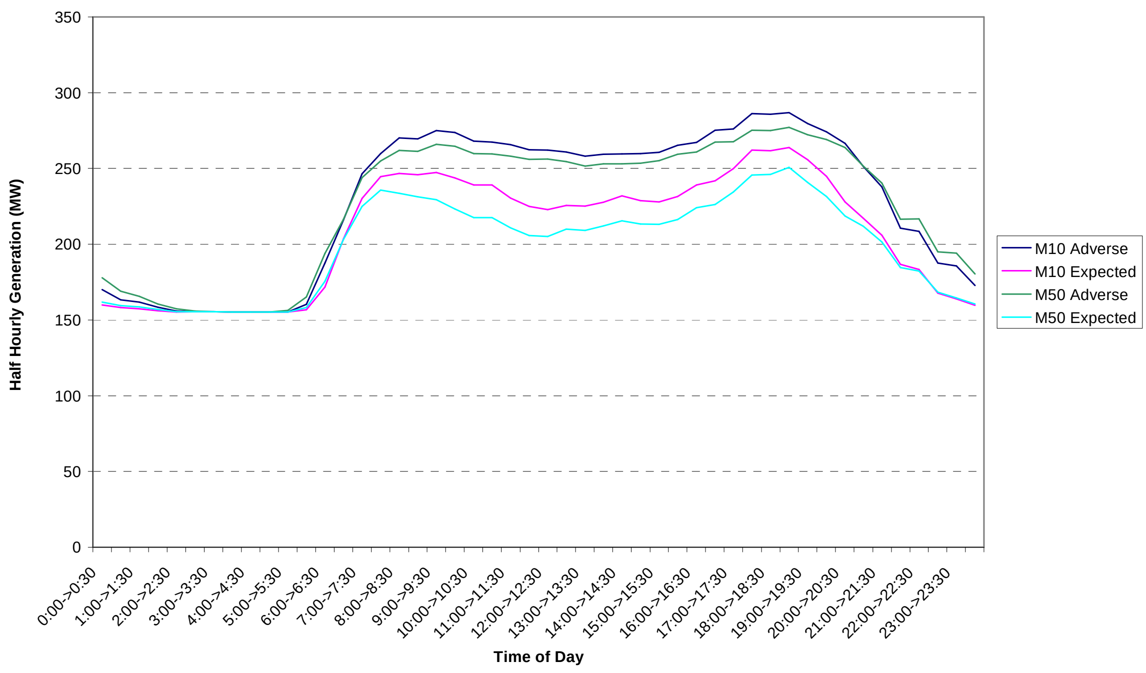
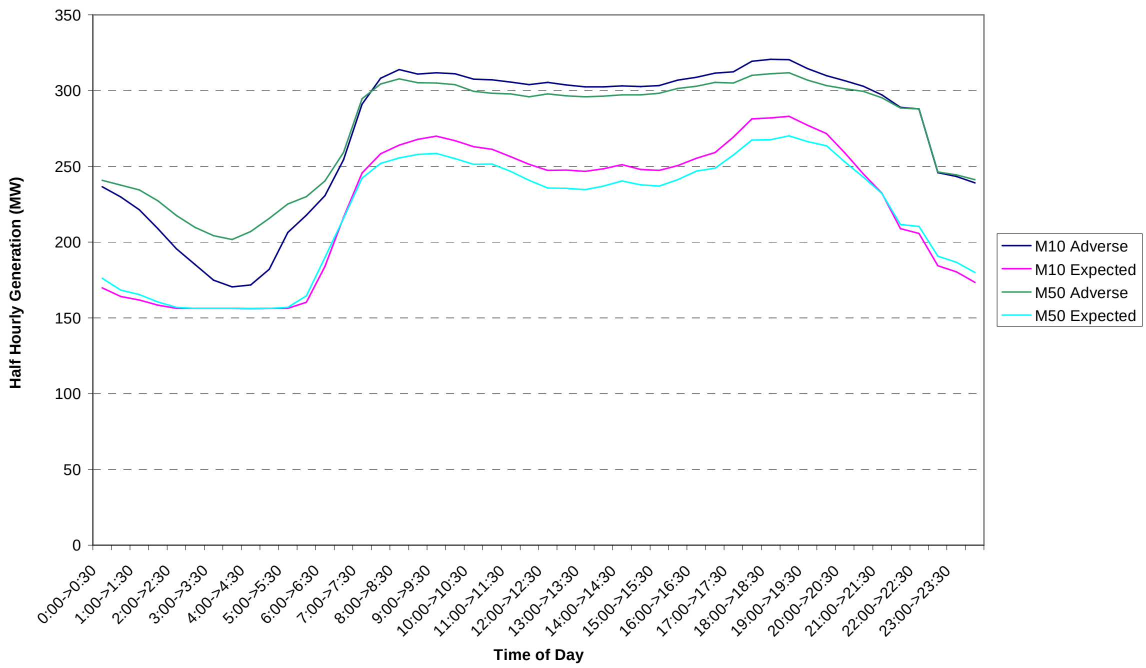


Figure 12.6 – Tallawarra Time of Day Generation in 2016 for four cases



The high efficiency and low fuel emissions factor of CCGTs relative to coal-fired generators leads to a lower overall emissions factor for these plants. As would be expected, under these load growth assumptions CCGTs benefit considerably from any increase in carbon price, and can expect to be amongst the most advantaged of all available technologies from the introduction of the CPRS. With different load growth assumptions, however, CCGTs may not experience such pronounced benefits (for example, a significant reduction in demand due to energy efficiency and response to high prices is likely to reduce the volumes of gas-fired plant before coal-fired plant, except under very high emissions permit prices). The future price of gas will also be a critical factor; the results reported in this chapter assume a continued low price of gas, but there is a significant likelihood that gas prices will rise substantially over the forecast period. This will also serve to reduce the competitiveness of gas-fired generation.

The increase in CCGT generation illustrated in these results will serve to smooth the gas offtake from pipelines, increasing gas pipeline utilisation and lowering the average price of gas delivered to the city gate in state capitals.

Figure 12.7 shows the average time of day generation for Swanbank E. Under these scenarios, Swanbank E is forecast to continue to operate on a relatively fixed profile regardless of year, drought, or emissions permit price. This is consistent with current operation under the Queensland GECs scheme which subsidises gas power plants to the extent of $15/MWh.

Figure 12.7 – Swanbank E Time of Day Generation in 2013 and 2016 for four cases

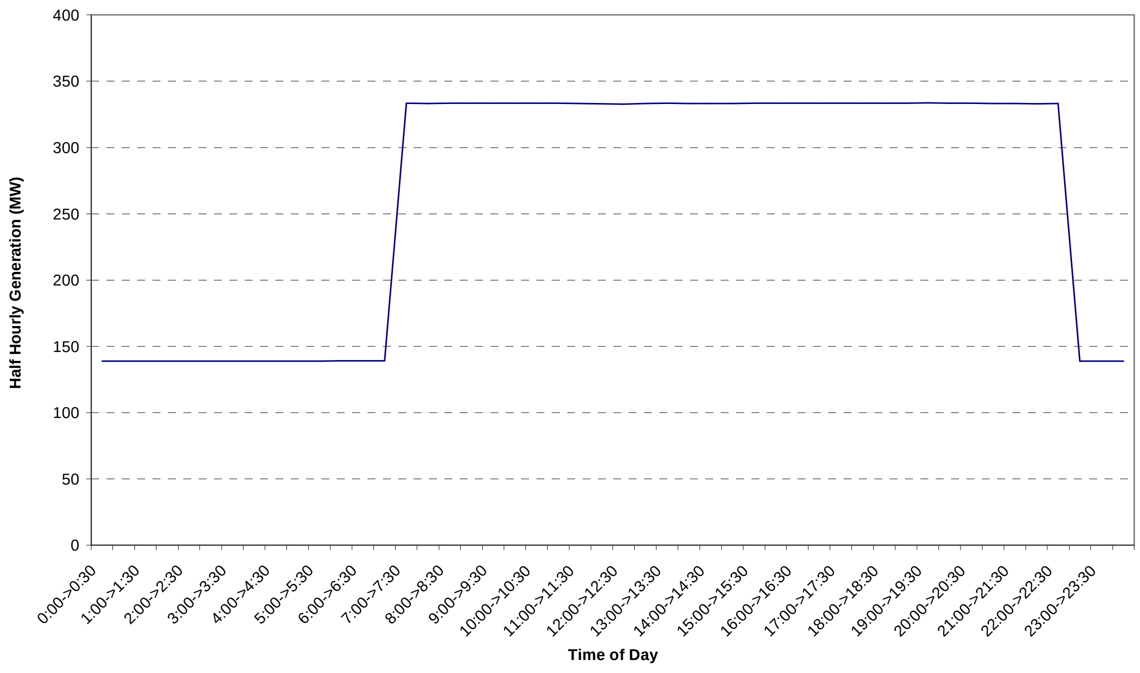


Figure 12.8 and Figure 12.9 show the time of day generation profile for Pelican Point in 2013 and 2016. By 2016, under the 'adverse' cases (with the higher level of emissions permit price), Pelican Point has increased volumes in the early morning hours (because it can compete with the coal-fired generation in SA such as Northern). This creates a much "flatter" profile compared with 2013. However, in the "expected" cases in 2016, the lower emissions permit price is insufficient for Pelican Point to compete against coal-fired generation in the early morning periods, and it shows the same overnight cycling as in the earlier years. This demonstrates that even for the low gas prices assumed in this study, a reasonable level of emissions permit price is required to produce fuel-switching.

Figure 12.8 – Pelican Point Time of Day Generation in 2013 for four cases

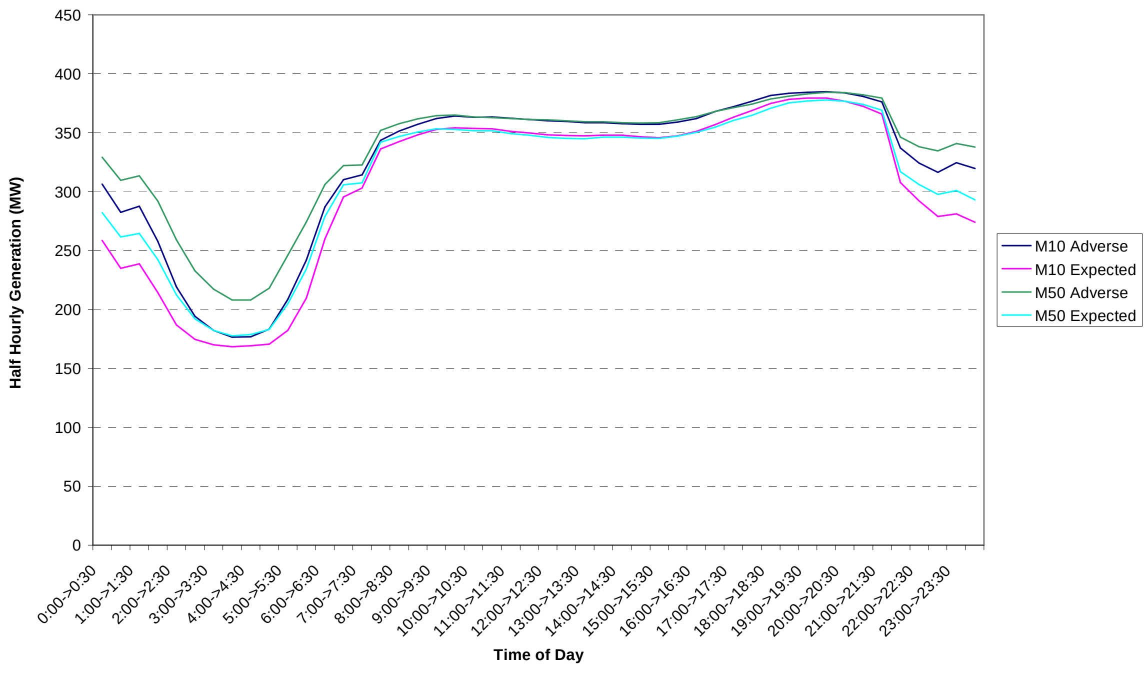
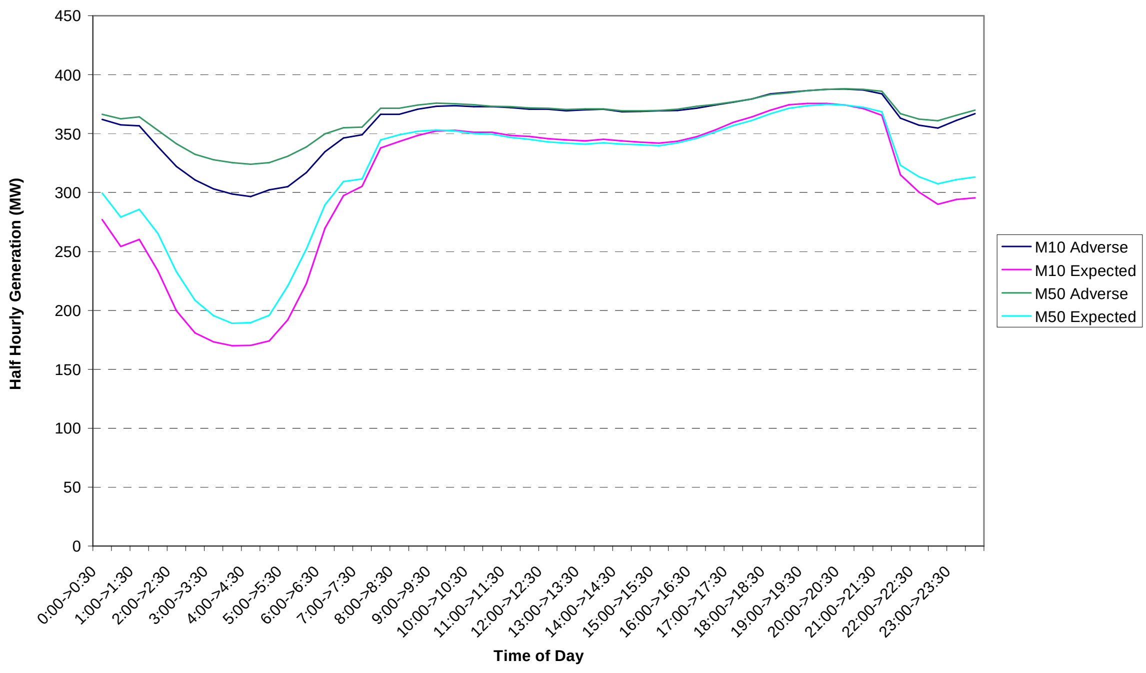


Figure 12.9 – Pelican Point Time of Day Generation in 2016 for four cases



Box 22 – Impacts of the CPRS and RET on CCGTs
CCGTs are likely to be beneficiaries of the CPRS as they are both fuel efficient and use fuel with low emissions intensity. The number of CCGTs is likely to increase but will be limited by high gas prices and the lack of volumes needed if there is significant demand response to high prices stimulated by the CPRS.

12.3) OCGTs (PEAKING PLANT)

OCGTs are not expected to benefit greatly from the introduction of a CPRS, owing to less favourable emissions factors, being less efficient than CCGTs. Open cycle gas turbines such as Uranquinty typically operate less than 10% of the time. Peaking plant are, however, likely to be affected by changes in price volatility due to the CPRS and introduction of large quantities of intermittent wind generation (discussed in detail in section 11).

Figure 12.10 and Figure 12.11 show forecast generation by time of day for Uranquinty in 2013 and 2016. As expected, Uranquinty runs more in the M10 cases (with the peakier demand profile), and the drought conditions in the 'adverse' case also contribute to a higher average time of day operation. However, no significant change is evident as the emissions permit price increases between 2013 and 2016.

Figure 12.10 – Uranquinty Time of Day Generation in 2013 for four cases

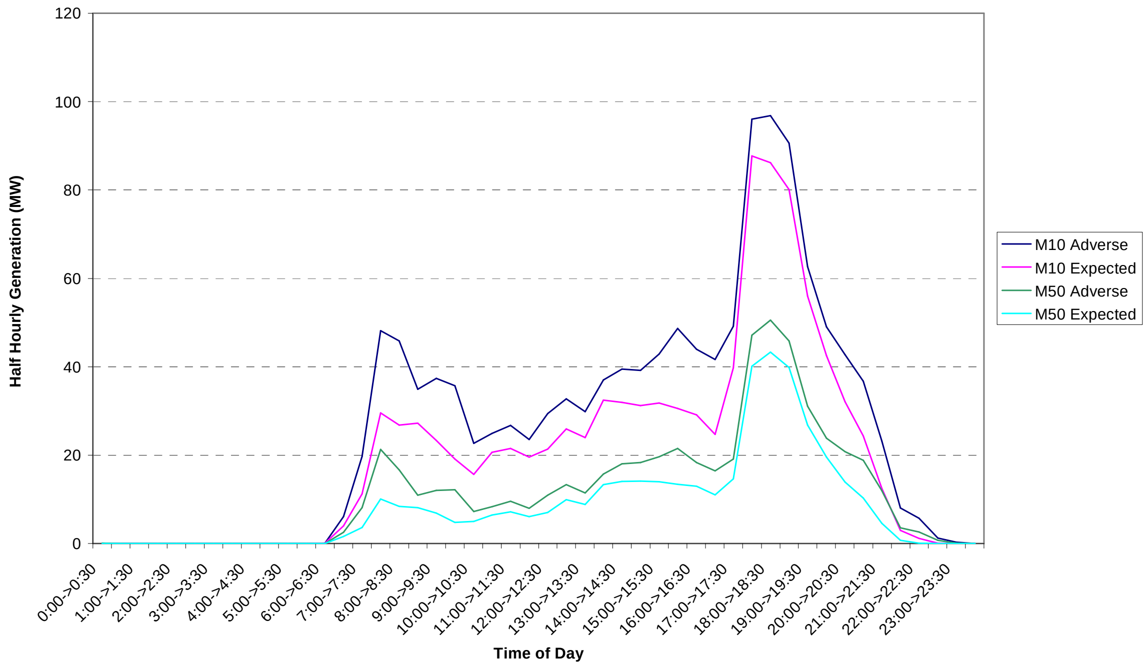


Figure 12.11 – Uranquinty Time of Day Generation in 2016 for four cases

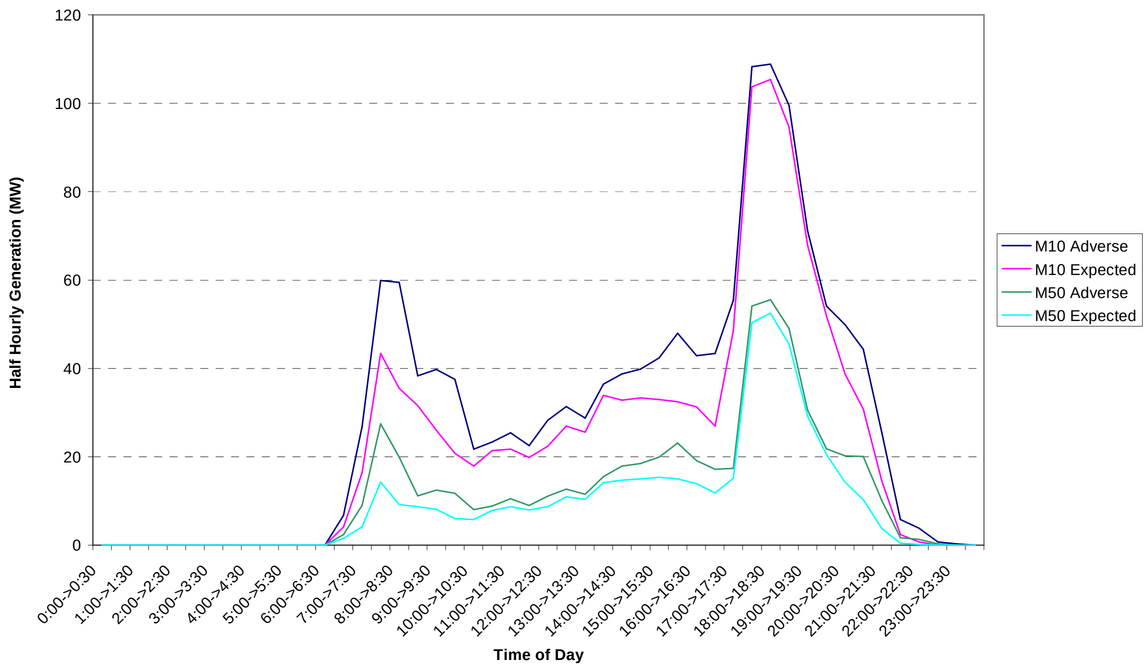


Figure 12.12 and Figure 12.13 show the forecast generation duration curve for Uranquinty in 2013 and 2016. Forecast operation under a higher carbon price does not show a significant change in the dispatch of OCGTs; Uranquinty generation is only slightly higher in 2016, even in the M10 cases. Differences are much larger between the two climatic year types, M10 and M50, than the effect of the CPRS (OCGTs are more likely to be dispatched under more extreme weather conditions, either hotter or colder).

Figure 12.12 – Uranquinty Generation Duration Curve in 2013 for four cases

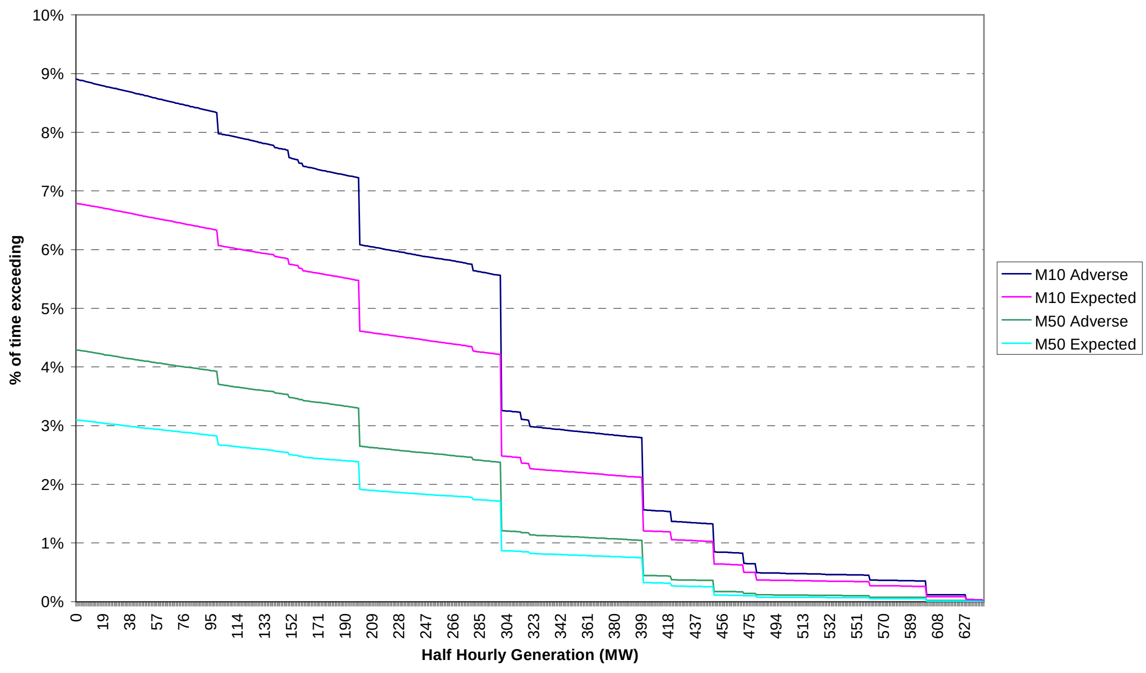


Figure 12.13 – Uranquinty Generation Duration Curve in 2016 for four cases

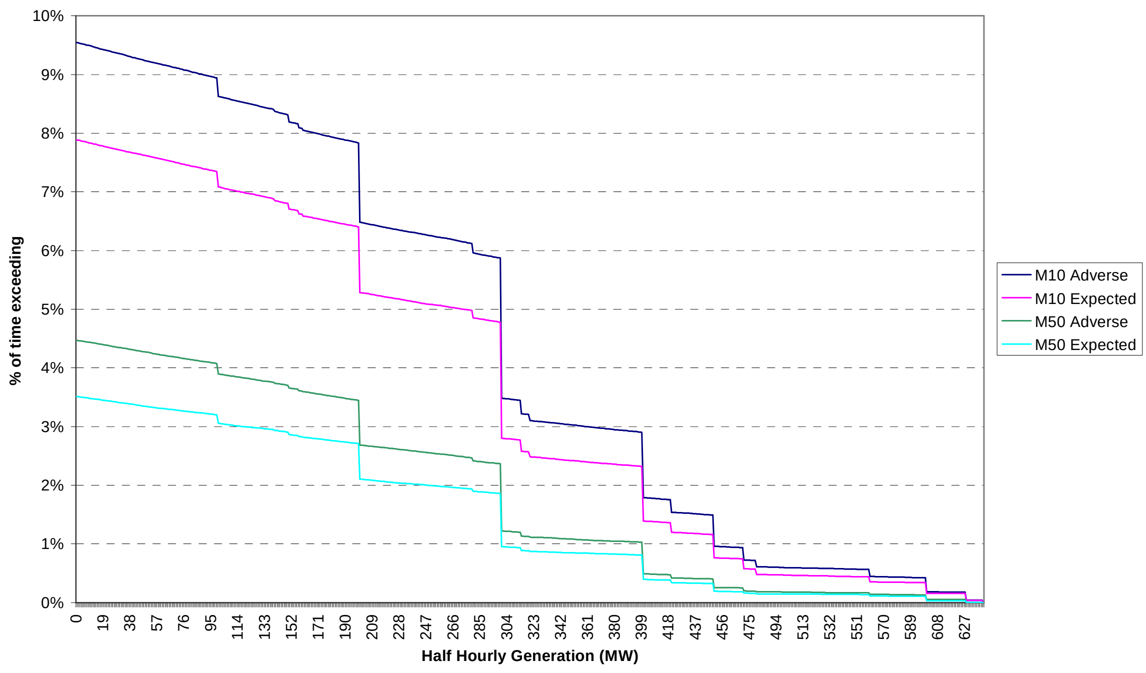


Figure 12.14 and Figure 12.15 show forecast time of day generation for Braemar, a large OCGT station in South West Queensland. In all cases, the generator is forecast to maintain a similar profile with generation slightly uplifted due to high demand growth in Queensland between 2013 and 2016.

Figure 12.14 – Braemar Time of Day Generation in 2013 for four cases

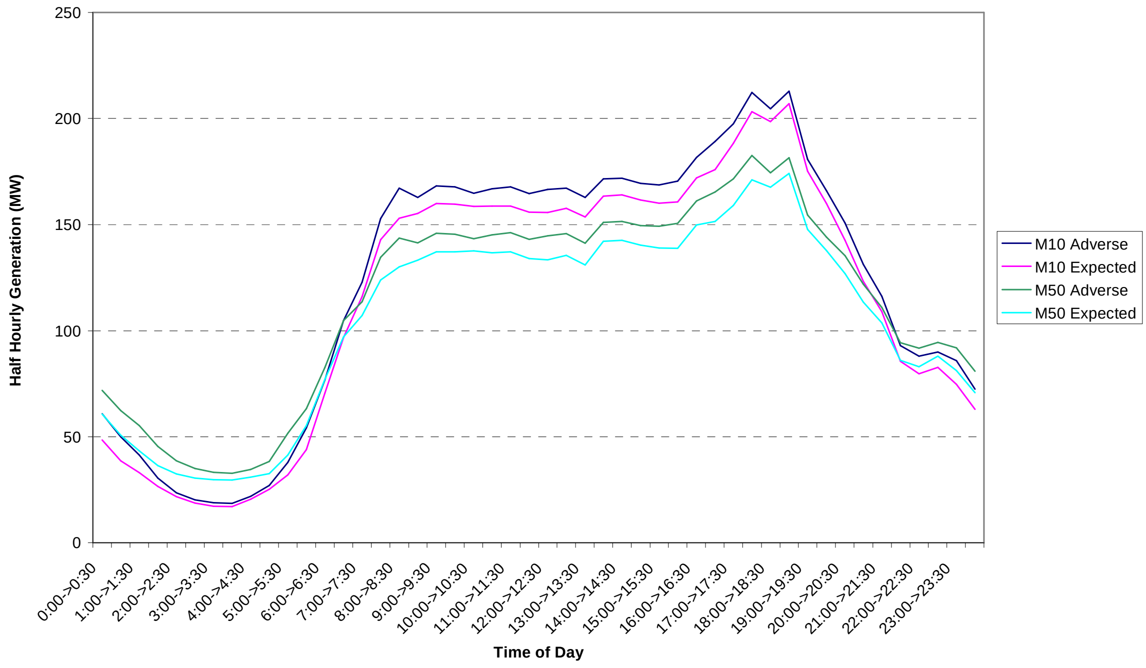
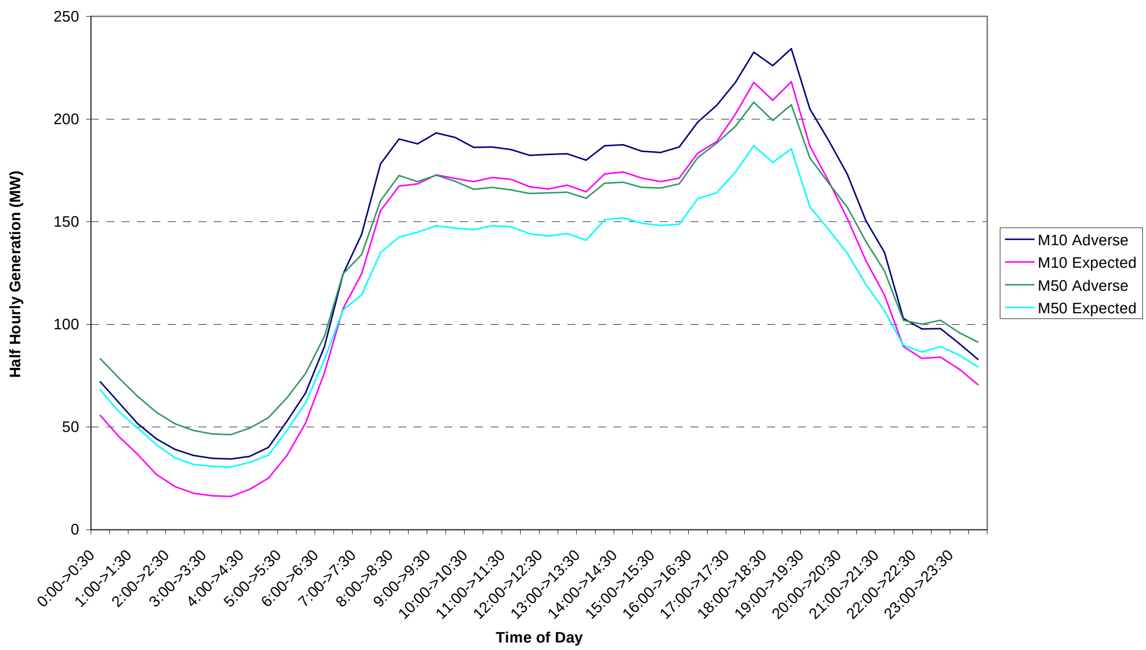


Figure 12.15 – Braemar Time of Day Generation in 2016 for four cases

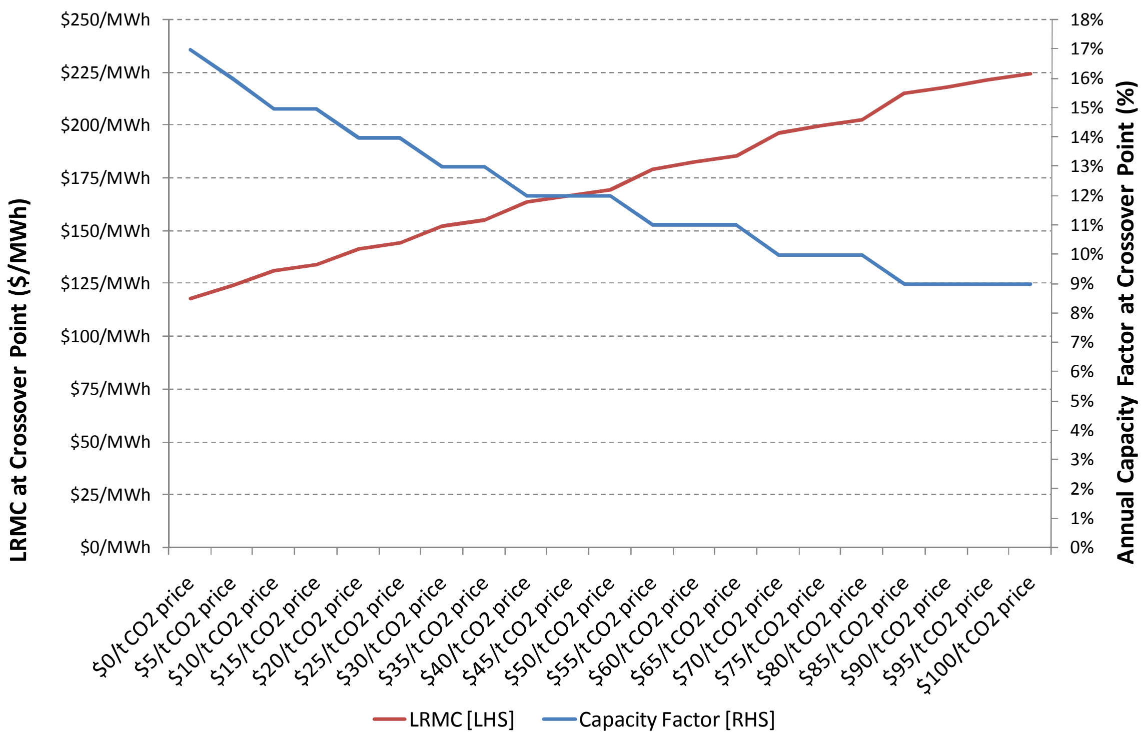


12.3.1) Impact on Investment in Peaking Generation

Generation capable of meeting short term shortfalls in generation requires technical capabilities for fast response. This being the case, simple cycle (Open Cycle) gas turbines are typically the technology required to meet this niche in the electricity market. OCGT technology is also favoured as it is presently the lowest capital cost generator capable of being developed in the scale necessary in large power systems, in the order of several hundred megawatts. OCGT power stations also can be developed with a relatively small 'footprint' in terms of land area required and as such are more likely able to be developed close to load centers where they are required.

Introduction of CPRS will certainly have an impact on the economics of generation investment. There is a risk that perceived economics of generation investment may be skewed with increasing carbon price, leading investment away from the technically necessary OCGT plant, towards CCGT technology which may be less capable of operating in the peaking mode over the long term. Figure 12.16 below shows the crossover point in terms of annual capacity factor where OCGT and CCGT long run marginal cost intersects[46].

Figure 12.16 – OCGT vs CCGT Economics



This shows that with increasing CPRS carbon price the capacity factor crossover point for OCGT and CCGT declines. This may invoke a trend towards reduced OCGT technology development in favour of higher capital cost CCGT plant. Whilst this seems a logical

46 Key assumptions are $5/GJ gas price. Capital costs are set at $720/kW OCGT and $1050/kW CCGT on the March 2007 ACIL Tasman report on generator costs.

progression on face value, operating CCGT plant with a larger number of stops and starts may lead to increased maintenance costs over the long term which could in turn lead to a reduction in long term efficiency of the market. Further to this the technical capability for fast response by OCGT capacity is not shared by CCGT plant which may lead to shortfalls in ramping capability depending on the loading of steam plant in the region.

It has been suggested that ramp rate constraints may provide additional revenues to OCGTs through the FCAS or spot markets. In the current FCAS markets of the NEM, OCGT plant has only limited scope to participate and hence earn revenue. This is due primarily to the timeframe in which the frequency control services are defined and the typical peaking/standby mode of operation for an OCGT. Gas turbines have very poor efficiency when only partially loaded and for this reason (along with fuel availability and cost concerns) typically do not run continuously. The vast majority of frequency control services are currently provided by steam and hydro plant, as steam plant is usually already operating, while hydro plant has very rapid response capabilities.

The only frequency control service an OCGT on standby currently appears to be able to provide is delayed contingency raise, which requires a less than 5-minute startup time, which may be achievable by some OCGT plant. However in the current market this service does not represent a significant revenue stream, and starting up in the required timeframe may impose additional maintenance requirements on the plant, increasing costs and decreasing overall plant availability.

Transmission congestion and the long lead times required for transmission development may lead to an increased requirement for generation grid support as an alternative or interim measure to maintain adequate levels of reliability of supply. There is currently a framework for allowing transmission network service providers to contract with generators for supply of grid support services. This is typically a measure which is applied to circumstances where transmission congestion is in the direction ‘away’ from the regional reference node. The rules associated with the interaction between generators and transmission network service providers may need to be reviewed where grid support is a viable alternative to transmission development where transmission congestion is causing supply scarcity ‘towards’ the regional reference node. This may help to support generation development in the form of a contract between the transmission provider and the generator, and also provide a mechanism for mitigating extreme price volatility caused by insufficient transmission capability.

With respect to large scale wind generation development and investment in peaking (and other) generation capacity, of key importance is the assumed contribution of intermittent generation to meeting peak demand. The ‘contribution factor’ for intermittent generation feed into the annual Supply-Demand Balance Outlook as part of the NEMMCO Statement of Opportunities. The supply-demand balance outlook is one of the most important information sources available to potential generation investors in the NEM. Should the assumed contribution factor for intermittent generation be overstated, two issues will present themselves. Firstly, if the peak contribution factor is overstated then there will potentially be insufficient generation to meet demand in the real-time market, leading to load shedding. Secondly, overstating the peak contribution factor in the supply-demand balance outlook assessment will lead investors to delay project development which will exacerbate the shortfall of generation capacity at times of peak demand even further.

Box 23 – Impacts of the CPRS and RET on OCGT investment
For OCGTs, the benefit from the CPRS is marginal, since they are less efficient than black coal fired generators, which offsets to a degree the lower emissions of gas relative to coal. Also, the RET scheme will not be helpful as it is likely to lower the incidence of high pool prices relative to without RET, meaning there is less opportunity for a peaking plant to run and hence recover its fixed costs. Therefore, the incentives for OCGTs to develop to support intermittent renewables will be weak.

12.3.2) Further issues related to intermittency of wind generation

An important issue to consider with the introduction of the CPRS and expanded RET is the intermittency of wind generation, and how this may impact upon system reliability. ROAM has studied periods when the demand in a region and the wind generation available in that region move quickly in opposite directions.

ROAM's analysis focussed on South Australia in the year 2016 by which time large amounts of wind generation are forecast to have been installed (some 1600 MW being possible). In four half hour periods during the year, the demand was forecast to increase by more than 500 MW at the same time as wind generation was forecast to decrease by more than 100 MW. Similarly, in six half hour periods, the demand was forecast to decrease by more than 500 MW at the same time as wind generation was forecast to increase by more than 100 MW.

During these ten periods, the stations which made up the differences were (most often) the OCGTs Hallett, Mallala and Quarantine, plus the Osborne cogeneration plant and Torrens Island B steam/gas turbine. At these times of extreme movements in wind generation and demand, the gas generation plants of South Australia have to ramp up by up to 760 MW or ramp down by up to 812 MW in the space of one half hour period. These higher than usual movements are exacerbated by the wind generation and demand moving in opposite directions. The demand changes in these periods are shown in Table 12.1 below.

Table 12.1 – Periods of opposing wind and demand movement in South Australia, 2016

Date and Time	Change in Wind Generation (MW)	Change in Gas Generation (MW)
09/05/2016 06:30	-104	667
02/07/2016 17:30	-104	658
30/12/2016 14:00	-133	653
30/12/2016 15:30	-130	760
25/04/2016 09:00	107	-736
28/04/2016 09:30	140	-812
24/05/2016 10:00	132	-781
22/06/2016 10:30	151	-689
30/06/2016 09:30	117	-765
16/12/2016 17:30	110	-703

The levels of intermittent plant currently installed in the market is not significant enough to cause such excessive changes in demand and generation between periods. Generally, a region must be either be import constrained or nearly import constrained and have most generation fully dispatched for variability to result in price spikes. In the current market environment, unconstrained interconnectors provide near immunity to ramping-related price spikes unless the entire NEM is experiencing supply scarcity, due to the large number of units that would be expected not to be operating at their maximums throughout the system as a whole. However, large increases in the penetration of intermittent plant as is likely under the RET and CPRS may outstrip the capability of the existing interconnection to smooth out the effects, meaning significant price volatility may eventuate during large swings in output from intermittent generators.

Widespread wind farm penetration such as is expected in a RET and CPRS future may be expected to increase both per-period variation in demand on scheduled units, and reduce the quantity of controllable plant available to respond to such events. Increased use of combined cycle plant may also reduce the quantity of controllable plant available to respond, as CCGTs are likely to run at near full capacity or not at all; similar to OCGTs, their efficiency drops rapidly when partially loaded.

Box 24 – Wind intermittency issues

Combined shifts in demand and wind generation within a single half hour period in South Australia were found to be up to 800 MW for a projected 2016 year with 1600 MW installed wind. This requires a rapid response from peaking generation to maintain system reliability. However, an OCGT is only likely to earn revenue from such events if it already happens to be synchronised and generating.

There is currently only very limited opportunity for peaking plant to take advantage of revenue streams sourced from ancillary services markets. However, considerable advances have been made in short-term wind forecasting, and accuracy may be expected to improve further in the near future. Therefore it may be possible to define a new FCAS service specified over a longer timeframe than current services to respond to forecast wind variability. This may help address both the profitability of standby plant such as OCGTs and provide a means to address some of the negative market effects of higher wind penetration.

13) COAL-FIRED GENERATOR PROFITABILITY ANALYSIS

A selection of ROAM's latest modelling results have been used to analyse the profitability of coal-fired generation under the CPRS and RET[47].

The modelling discussed here assumes that load growth is not reduced in response to increased carbon prices. In reality, the growth in electrical load may reduce with an increasing carbon price, as residents, businesses and industry are incentivised to minimise the consumption of energy. Industrial growth in particular may be reduced by a

[47] All input data used in modelling is based on public domain sources, such as: ACIL Tasman, 'Fuel resource, new entry and generation costs in the NEM Report 2 – Data and documentation' Draft prepared for NEMMCO, 27 March 2007.

high priced CPRS, as energy forms a significant component of the costs of many industrial processes. If load growth is reduced, it would tend to reduce the results shown here (generator volumes would lessen as the demand for energy reduces, and profits may fall marginally).

Various factors have determined by ROAM to be indicators of the likelyhood of a power station being forced to retire under the RET or the CPRS. These are summarised in Table 13.1 below.

Table 13.1 – Identification methodology for potential retirement of stations

Reason for potential retirement	Description	Considered 'marginal' if:	Considered 'likely' if:
Competitive forces (due to the RET)	Loss of generation due to new entrants, including renewables to meet the RET, without a price on emissions (i.e. $0/t CO2-e)	loss of capacity factor is > 10% of 2009-10 levels	loss of capacity factor is > 20% of 2009-10 levels
Loss of production (due to the CPRS)	Loss of production due exclusively to the application of a price on emissions, in this case $40/t CO_2-e	loss of capacity factor is > 10% of 2009-10 levels	loss of capacity factor is > 20% of 2009-10 levels
Loss of earnings (due to the CPRS)	Loss of earnings due to the application of a price on emissions, in this case $40/t CO_2-e	earnings are < $20 million per annum	earnings are < $0 per annum

Table 13.2 below uses these methodologies to summarise the potential for existing generators to be forced to retire in the medium term[48] assuming a moderate price on emissions ($40/t CO_2-e). As the table shows, only old, inefficient plant in each region are considered potentially unviable within a emissions constrained market, even under a moderately high emissions permit price of $40/t$CO_2$.

Table 13.2 – Potential for Retirement for existing coal fired generators

Coal Fired Power Station	Reason for Potential Retirement		
	Competitive forces	Loss of Production (due to CPRS)	Loss of Earnings (due to CPRS)
Gen 1	Unlikely	Unlikely	Unlikely
Gen 2	Unlikely	Unlikely	Unlikely
Gen 3	Unlikely	Unlikely	Unlikely
Gen 4	Unlikely	Unlikely	Unlikely

[48] The medium term has been defined as the 2015-16 financial year.

Table 13.2 – Potential for Retirement for existing coal fired generators

Coal Fired Power Station	Reason for Potential Retirement		
	Competitive forces	Loss of Production (due to CPRS)	Loss of Earnings (due to CPRS)
Gen 5	Unlikely	Unlikely	Unlikely
Gen 6	Unlikely	Marginal	Marginal
Gen 7	Unlikely	Unlikely	Unlikely
Gen 8	Unlikely	Unlikely	Unlikely
Gen 9	Unlikely	Unlikely	Unlikely
Gen 10	Unlikely	Unlikely	Unlikely
Gen 11	Unlikely	Likely	Marginal
Gen 12	Unlikely	Unlikely	Unlikely
Gen 13	Unlikely	Unlikely	Unlikely
Gen 14	Unlikely	Unlikely	Unlikely
Gen 15	Unlikely	Marginal	Unlikely
Gen 16	Unlikely	Unlikely	Unlikely
Gen 17	Unlikely	Unlikely	Unlikely
Gen 18	Unlikely	Unlikely	Marginal
Gen 19	Unlikely	Likely	Marginal
Gen 20	Unlikely	Unlikely	Unlikely
Gen 21	Unlikely	Unlikely	Unlikely
Gen 22	Unlikely	Marginal	Marginal
Gen 23	Unlikely	Unlikely	Unlikely
Gen 24	Unlikely	Marginal	Unlikely

Box 25 – Potential for retirement of coal-fired generation under the CPRS

ROAM has analysed the potential for forced retirement of each individual coal-fired power station in the NEM, due to competitive forces under the RET, or loss of production or revenue under the CPRS. ROAM's results show that only old, inefficient plant in each region are considered potentially unviable within a emissions constrained market, even under a moderately high emissions permit price of \$40/tCO_2. None are threatened by the RET.

The following two sections discuss in further detail the impact on generation volumes and annual earnings for coal generators with the CPRS.

13.1) GENERATION VOLUMES UNDER THE CPRS

Coal-fired generators are designed to operate at very high capacity factors to maximise plant efficiency and minimise costs. A significant loss of generation, caused by the increased costs associated with emissions permits and the failure to maintain competitive advantage in light of these higher costs will require either cycling of existing units or mothballing of units in order to maintain high levels of operation on the remaining units. Generating flexibility for those generators at risk of a loss of volume will become important, and has already been used at the Gladstone power station and within the Macquarie Generation portfolio.

In general, the introduction of a price on emissions permits around \$40/t CO_2-e would not significantly affect the majority of existing plant. ROAM's modelling has forecast that, for the majority of generators, coal fired units will maintain their generation volumes going forward despite the introduction of a price on emissions and increased generator competition due to the installation of a significant capacity of renewable generation to meet the RET.

There are however generators which are more vulnerable to loss of dispatch than others, due to their emissions intensity. Older, inefficient plant using outdated technologies will tend to fall down the dispatch merit order by attempting to incorporate the cost of emissions permits into their bid prices. ROAM's modelling suggests that this loss of generation will be captured by (primarily) other less emissions intensive coal generators and some mid-merit gas fired plant.

In New South Wales, generators such as Liddell, Wallerawang and Redbank are forecast to be more affected than other coal plant. In Queensland, older plant such as Callide B, Gladstone and Swanbank B are the most likely plant to experienced reduced generation volumes. In Victoria, Hazelwood, Yallourn and Morwell power stations also are forecast to be most affected.

ROAM's modelling suggests there are existing coal generators which may become more competitive under the CPRS, due to their relatively lower emissions intensity. In New South Wales, generators such as Bayswater and Eraring are most likely to recover generation lost by less efficient plant. In Queensland, newer generators such as Kogan Creek, Callide C, Tarong, Tarong North and Millmerran may benefit, while in Victoria most other brown coal stations (other than Hazelwood, Yallourn and Morwell) are forecast to maintain generation volumes.

Box 26 – Coal-fired generation under the CPRS

ROAM's modelling consistently shows that individual coal-fired generators will be affected very differently by the CPRS. Some will show severe reductions in volume (and therefore revenue). Others, however, are likely to show increased volumes (compensating in part for the reduced volumes from the most emissions intensive plants). This combined with the expected increase in the pool price will therefore mean that some coal generators experience very mild revenue impacts.

The impacts on generators cannot be determined from their emissions factors alone, since the outcomes are heavily dependent on transmission limitations between regions. It is therefore incorrect to assume that all brown coal generators will be more severely impacted than black coal generators (since brown coal generation is exclusively located in Victoria). Some highly emitting coal generators are likely to show increased volumes under the CPRS, to compensate for the reduced volumes of other plants in that region.

13.2) PROFITABILITY OF GENERATORS UNDER THE CPRS

It is commonly believed that coal fired generators will be the most severely affected by the CPRS in terms of their ongoing viability. The profitability of the existing coal fired generators is expected to fall with an increasing carbon price, however for most generators the viability of each business should remain robust, even under very high carbon prices and increased competition driven by the RET.

In the long term, unprofitable plant will be replaced by low emissions generators by market forces. However, to ensure system security, it is necessary for existing plant to remain profitable in the medium term. In the period before which new entrant replacement plant may enter it is necessary that all existing plant remain operable to ensure that adequate capacity be available to meet system demand.

Of all existing coal generators, those identified above as slipping down the dispatch order warrant further analysis.

Detailed cost information for each existing generator is not publicly available, which makes it impossible to determine the true profitability of existing plant. However, ROAM's modelling has been used to develop estimates of earnings after operating costs (including fuel, variable O&M and emissions permits) and annual fixed maintenance costs. From this, it is apparent that some existing coal fired plant will be unlikely to operate in the long term under a high priced CPRS without some form of external support.

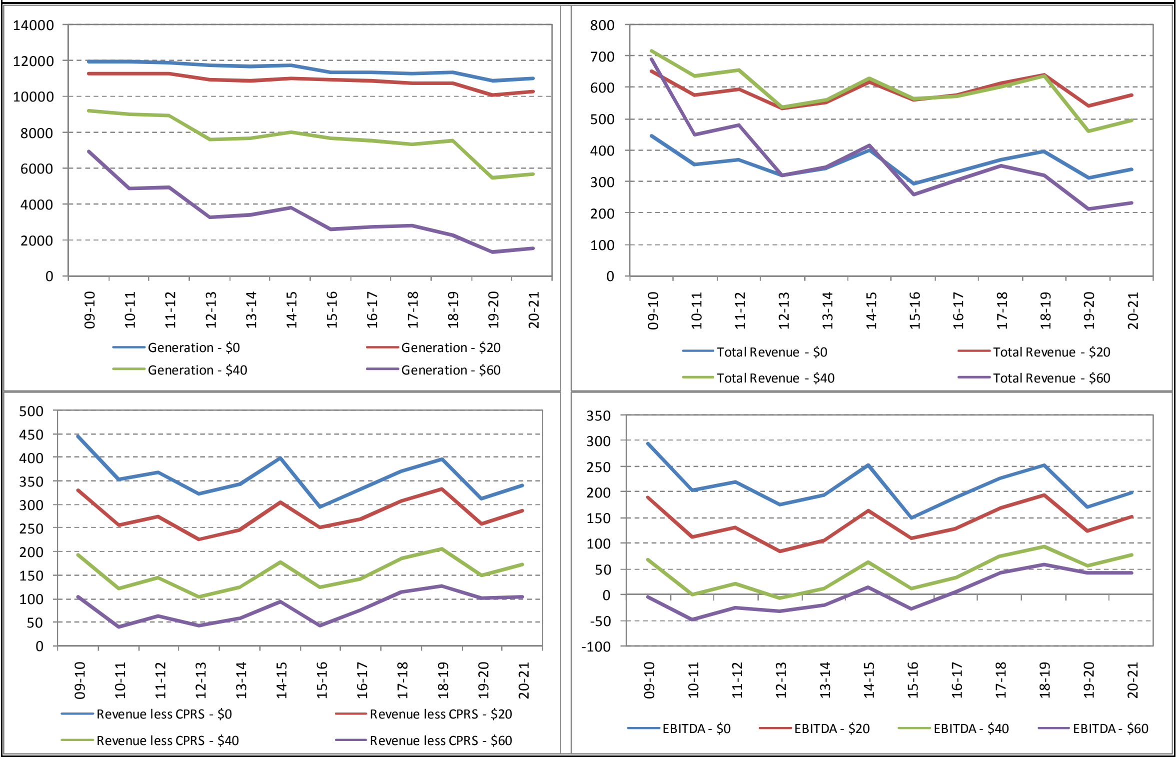
13.2.1) Victorian brown coal generators

It is popular belief that as the highest emissions plant in the NEM, brown coal generators will be forced to retire under even very low emissions permit prices. However, extremely inexpensive fuel costs and moderate maintenance estimates result in the plant remaining profitable in the near term when the cost of emissions is expected to be relatively low (~\$20/tCO_2-e).

In the longer term, if the CPRS is to be successful in achieving significant emissions reductions, it is anticipated that the cost of emissions will be significantly higher than when introduced (~\$60/t CO_2-e or above). ROAM's modelling suggests that at these prices, high emitting plant with relatively low efficiencies would be loss-making, and would be candidates for retirement. Newer plant with higher efficiencies (such as the Loy Yang power stations) would be viable in the long term even under very high emission prices, despite their high emissions intensity relative to the rest of the NEM.

The figures below demonstrate the significant separation between the best and worst performing brown coal generators in Victoria. Figure 13.1 illustrates the impact of various levels of emissions permit price on the profitability of Hazelwood Power station.

Figure 13.1 – Profitability of Hazelwood Power Station



The viability of Hazelwood power station appears vulnerable under a moderate carbon price. At $40/tCO_2$-e and above, the generator volumes of this high-emission brown coal plant is severely curtailed. This implies a greater number of start-ups, as the station is unlikely to remain capable of baseload operation, which would increase costs to a greater extent than estimated in the EBITDA[49] graph.

Figure 13.2 and Figure 13.3 show a similar profitability analysis of Loy Yang A and Loy Yang B power stations under varying levels of emissions permit price. These figures illustrate that despite the emissions intensity of these plants relative to the rest of the NEM, the operation of the Loy Yang power stations will remain relatively unchanged until significant competition can enter, irrespective of the carbon price. The profitability of the station is also only marginally affected (especially compared with other brown coal plant).

[49] Earnings before interest, taxes, depreciation and amortization.

Figure 13.2 – Profitability of Loy Yang A Power Station

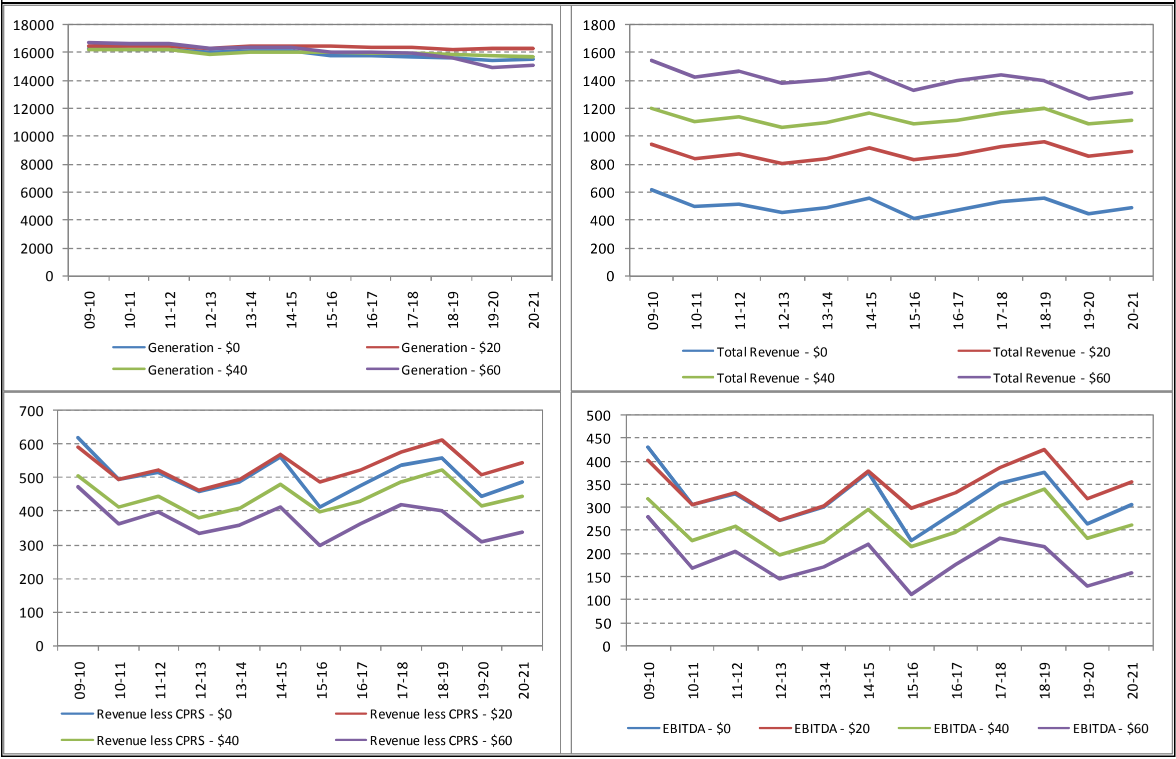
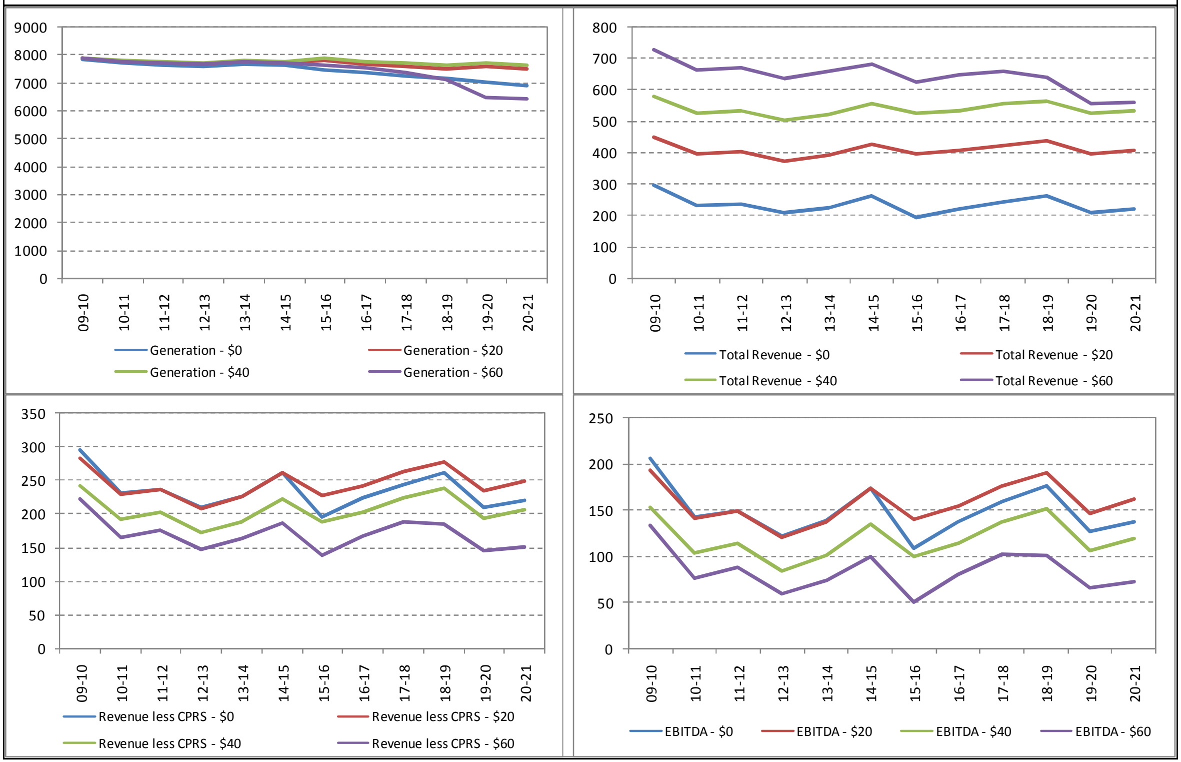


Figure 13.3 – Profitability of Loy Yang B Power Station



The likelihood of further potential retirements beyond those identified here may depend upon the flexibility of plant to operate at reduced levels. Some coal fired generators may have to cycle to avoid excessive penalties from carbon price. This may lead them to shut down overnight, which will increase their operating costs through use of oil for starting and also potentially increase Operations and Maintenance costs, or risk lower reliability.

Significantly, there is no single region that is more affected than another, since transmission limitations between regions will ensure that some coal fired base load generators remain competitive in each region. To maintain the viability of other threatened generators, consideration could be given to modifying ancillary service payments to allow them to obtain a larger revenue proportion from FCAS and NCAS services to compensate for loss of revenue from MWh produced. This would allow their volumes to decrease, thus reducing emissions, while underpinning their revenue levels to some extent through a default 'capacity' payment, thus ensuring they are available to contribute to reliability when needed.

Box 27 – CPRS effects on coal-fired plant
ROAM's results suggest that only the most inefficient plant are those likely to be threatened by an emissions reduction scheme. This plant tends to be close to the end of their useful life, and unless overhauled would tend to be candidates for retirement even in the absence of the CPRS. Hazelwood for example, built in the 1960s, would be over 50 years old when emissions prices are expected to rise to levels where it may lose money. Therefore, although some plant may be unviable at high emissions prices, this plant would likely require significant capital work to extend the life of the plant (to improve the efficiency of the station), or would be shut down and replaced with newer technologies. Contrary to popular belief, there is no single region that is more affected than another by the CPRS, since transmission limitations between regions will ensure that some coal fired base load generators remain competitive in each region. Transmission limitations serve to 'protect' the profitability of coal-fired generation, maintaining market volumes, whilst reducing the effectiveness of the CPRS at mitigating emissions.

13.3) EFFECT OF UNIT CYCLING OR RETIREMENT

Some generators may elect to retire or withhold one or several generating units to increase the wholesale pool price, and thereby the profitability of the remaining units within that station. The cycled units are withheld to very high spot market prices, remaining available to ensure system reliability.

This strategy already is in place at Gladstone power station and within the Macquarie Generation portfolio[50]. At present, rarely do all eight units at Gladstone operate. Macquarie Generation also manages its portfolio by usually operating only seven of the eight units operating at Liddell and Bayswater power stations. The withholding up to

[50] Macquarie Generation Annual Report 2004: 'Electricity demand continues to grow modestly and unabated. This provided the opportunity to increase production by using seven of our eight available units during higher demand periods in winter and summer.'

900MW of capacity between these three power stations increases the pool price, and increases performance by optimising maintenance schedules. Plant efficiency is also improved, with a higher operating load amongst those units online. Competing generators also benefit, as the higher pool prices feed into higher revenues for all generators.

Box 28 – CPRS effects on coal-fired plant
ROAM's modelling suggests that in the medium term, all plant should be considered profitable with mild emissions prices. This would depend upon their capacity to provide a more flexible mode of operation, as identified by some stations losing a material proportion of generation due to the effects of the varying increase in costs associated with emissions permits. In the longer term, as the price of permits rises to high levels, older less efficient plant may lose competitive advantage, losing generation to other coal units or new or existing gas plant, and may prove unprofitable. The market must be capable therefore of providing enough incentive for high capacity factor plant such as low emissions coal or combined cycle gas to enter the market to replace those unprofitable power stations. If the wholesale pool price does not provide sufficient stimulus for this development, the AEMC and NEMMCO must find alternative avenues to ensure system security. Some coal fired generators may have to cycle to avoid excessive penalties from carbon price. This may lead them to shut down overnight, which will increase their operating costs through use of oil for starting and also potentially increase Operations and Maintenance costs, or risk lower reliability. Transmission limitations between regions will ensure that some coal fired base load generators will remain competitive in each region, irrespective of the emissions intensity of the plant. Ancillary services rules may have to be modified to allow less efficient generators to obtain a larger revenue proportion from FCAS and NCAS to compensate for loss of revenue from MWh produced.

14) CONCLUSIONS AND RECOMMENDATIONS

The National Electricity Market and Gas Market objectives focus on efficient investment in and efficient operation of each market, and do not contain environmental objectives of any kind, despite the original 1991 brief seeking "environmentally sound development of the electricity industry". Instead, economy wide schemes such as the CPRS (Carbon Pollution Reduction Scheme) have been proposed, together with an expanded RET (Renewable Energy Target) to promote renewable and low emissions generation. Studies have been performed by several companies on the effect of these schemes on the electricity and gas markets, and the possible interactions of these two schemes. ROAM has also performed studies for many companies and government departments containing modelling of the effects of these schemes.

What ROAM believes to be the most significant findings of this report, in terms of materiality, are summarised briefly here.

Lack of transmission inhibits renewable development

Lack of transmission capacity will result in a failure to bring forth development of the most economic renewables, in particular wind. This result has been embedded in the Treasury modelling assumptions by placing restrictions on the entry of wind generation in some regions, in particular South Australia.

Furthermore the CPRS scheme has the potential to encourage gas developments and further reduce justification for renewable stimulated transmission. The effect of insufficient transmission will be to develop sub-economic renewables in less windy areas.

The solution to this dilemma may be to create a framework for renewables to be supported by purpose built transmission to transport large amounts of wind generation from windy areas to load centres, such as:

- from Tasmania to Victoria
- from South Australia to Victoria
- from South Australia to Queensland.

Lack of transmission compromises the operation of the CPRS

Due to electricity transmission limitations between regions the efficiency of the CPRS will be seriously compromised. The most emissions intensive generators will not be exposed to the full effects of the emissions permit price because inter-regional transmission is insufficient. In addition, at the emissions permit prices that currently appear likely, fuel switching from coal to gas is unlikely (it is more likely that there will be a shift from the most emissions intensive coal plants to the less emissions intensive coal plants within each region).

Interaction of RET and CPRS

In summary, the primary limitation on the efficacy of the RET and CPRS to fulfil their intended function results from inadequate transmission capacity, particularly between regions of the NEM. This will be manifested in increased pool price volatility and transmission congestion, and potentially on reliability, depending on whether generators are forced to retire prior to sufficient new generating plant entering the market. The CPRS will also encourage more efficient new generators to enter, rather than the more flexible OCGT capacity that would support intermittent renewables.

Appendix A) About ROAM Consulting's modelling suite

A.1) Forecasting with 2-4-C

2-4-C was the primary tool used to produce the highly detailed modelling presented in this submission. The modelling presented here focuses on the NEM and WEM, although ROAM also has the capability to perform similarly detailed modelling simulations for smaller grids such as the NWIS (Pilbara), East and West Kimberley, Northern Territory and Mount Isa region.

2-4-C is ROAM's flagship product, a complete proprietary electricity market forecasting package. While capable of modelling any electricity network, with it in use in small systems such as the North-West Interconnected System (NWIS) of Western Australia, and the enormous 4000 bus CalISO system of California, ***2-4-C*** was built first and foremost to match as closely as possible the operation of the NEMMCO Market Dispatch Engine (NEMDE) used for real day-to-day dispatch in the NEM. ***2-4-C*** implements the highest level of detail, and bases dispatch decisions on generator bidding patterns and availabilities in the same way that the real NEM operates. The model includes modelling of forced full and partial and planned outages for each generator, including renewable energy generators and inter-regional transmission capabilities and constraints.

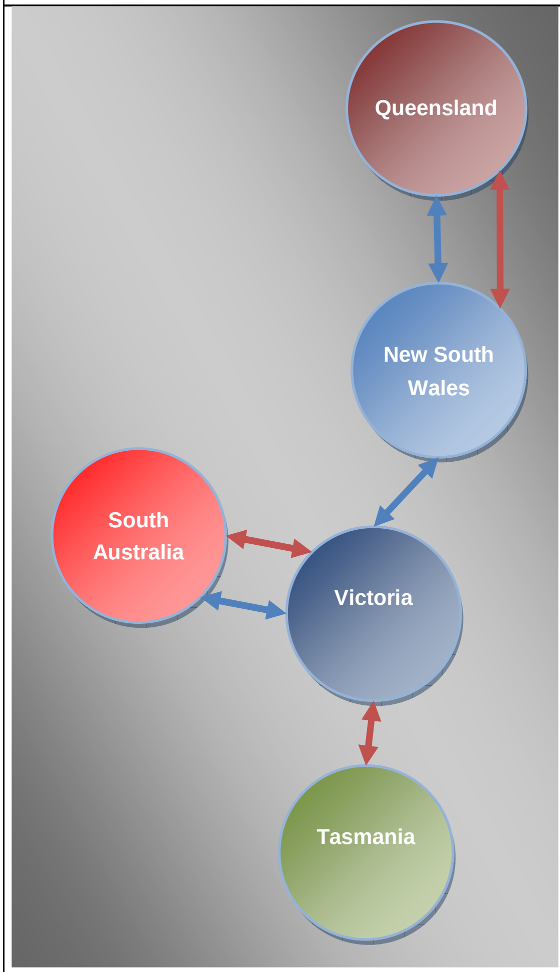
ROAM continually monitors real generator bid profiles and operational behaviours, and with this information constructs realistic 'market' bids for all generators of the NEM. Then any known factors that may influence existing or new generation are taken into account. These might include for example water availability, changes in regulatory measures, or fuel availability. The process of doing this is central to delivering high quality, realistic operational profiles that translate into sound wholesale price forecasts.

2-4-C has been used on behalf of NEMMCO since 2004 to estimate the level of reliability in the NEM and consequently set the official Minimum Reserve Levels for all regions of the NEM.

A.2) The 2-4-C Model

The multi-node model used to produce the forecasts in this report is shown in Figure A.1 . This nodal arrangement features a single node per region of the NEM is the same as that used in NEMDE.

Figure A.1 – *2-4-C* NEM Representation



Blue bi-directional arrows signify the AC interconnectors between the regions of the NEM, while the red arrows signify High-Voltage DC Links.

This network representation means that no visibility of intra-regional network capabilities exists directly. In order therefore to model these important aspects of the physical system, NEMMCO employs the use of Constraint Equations that in effect transpose intra-regional network issues to the visible parts of the network; that is, the inter-connectors joining the regions of the NEM. These Constraint Equations consist of several hundred mathematical expressions which define the interconnector limits in terms of generation, demand and flow relationships. ***2-4-C*** implements these Constraint Equations within its LP engine in fully co-optimised form. More detail on ROAM's modelling of the Constraint Equations is given in Section A.3).

Modelling major transmission lines and Constraint Equations delivers an outcome consistent with the real operation of the NEM under normal system conditions. Additionally, the occurrence of congestion in the network is the primary factor that drives out-of-merit dispatch outcomes and hence price volatility. These important aspects of the NEM would not be seen in a more simplistic model.

A.3) Modelling the Transmission System

ROAM's ***2-4-C*** dispatch model implements the full set of NEMMCO 2007 ANTS Constraints as supplied by NEMMCO with the 2007 Statement of Opportunities. These Constraint Equations define interconnector flow limits in terms of generation, demands and flows. A Constraint Equation for an interconnector is defined in a particular direction and will be of the following form:

$$X * Flow_{InterconnectorA_{DirectionB}} + Y * Output_{GenA} \leq$$
$$Constant + Z * Demand_{RegionA} + P * Output_{GenA} + Q * Output_{GenB} + R * Flow_{InterconnectorB_{DirectionA}}$$
$$where: X, Y, Z, P, Q \text{ are constants}$$

In this formulation, there are variables (called dispatchable terms in this context) on both the left and right sides of the equation. Linear Programming (LP) engines, which are used to evaluate the bids of generators and dispatch the NEM at least cost, are not able to fully optimise dispatch outcomes with constraints in this form. Instead they require that all variables be on the left side of the equation only. Therefore, this re-formulation is performed prior to submitting the constraints to the LP. This linear formulation is known as 'co-optimised' format. Therefore, prior to entering these Constraint Equations into ***2-4-C***, they are converted into co-optimised form.

A.4) Key Parameters used by the Model

Data contained within the ***2-4-C*** model is a combination of the best information sources within the public domain including:

- All released NEMMCO Statements of Opportunity through to 2007, together with half-hourly historical load profiles by region;
- Annual Planning Statements by Network Service Providers:
  - All published Powerlink statements through to 2008, together with half hourly historical load profiles by zone;
  - All published TransGrid statements through to 2008;
  - All published Vencorp statements through to 2008;
  - All published ESIPC statements through to 2008, and;
  - All published Transend statements through to 2008.
- Corporate Annual Reports up to 2007-08 for many market participants (generators, retailers and network service providers), and;
- General reports from market participants.

More specifically focussing on the assumptions used in the modelling presented in this submission is given in the following section.

Appendix B) Specific modelling assumptions

B.1) Assumptions with regard to the Demand Side

Inclusion of Customers

At each region, a bulk load consumption facility has been included to represent the cumulative, time-sequential, load consumption profile anticipated at each of the six regions used in the study.

Demand-Side Participation

The vast majority of demand in the wholesale market currently operates as a series of aggregated loads for the purposes of schedule and dispatch. Though some individual customers may be responsive to price, the majority of end-consumers are shielded from short-term price fluctuations through retail contracts. Thus, incentives to reduce demand during high-price periods are dissipated.

In this study, as detailed in the NEMMCO 2008 Energy and Demand Projections, DSP is captured as part of the actual measured demand for both cases and therefore inherently part of the demand forecast.

New Base Loads

No new base loads are included in this study.

Hydroelectric Pump Storage Loads

The ***2-4-C*** version used for this study includes a detailed hydroelectric model, including pump storage loads. The pumping loads for the following hydroelectric facilities have been included in the load profile:

- Wivenhoe power station;
- Shoalhaven power station
- Snowy Mountains Scheme: Tumut 3 power station.

B.2) Assumptions on the Supply Side (Generation assets)

Existing Projects

The market forecasts take into account all existing market scheduled generation facilities.

In this study, the likely commissioning schedule (beginning typically three months prior to commercial operation) for new generators has been taken into account.

Individual Unit Capacities and Heat rates

Details of unit capacities and heat rates (for thermal plants) have been collated and included on the basis of information available from the public domain.

Unit Emissions Intensity Factors

Emissions Intensity Factors have been collated from public sources and along with heat rates are the basis for determining the uplift in Short Run Marginal Cost under the Carbon Pollution Reduction Scheme.

Unit Operational Constraints

Information on unit minimum load and ramp rate constraints is included in the ***2-4-C*** database. This database has been developed based on pre-market information, moderated with information being currently supplied to the market.

Such information is taken into consideration in the simulation of market operation (to ensure that an infeasible solution is not simulated).

Forecast Station Outage Parameters

As noted previously, the Advanced Mode of modelling unit availability is used. This mode utilises independent schedules for each unit of:

- Planned maintenance, and
- Randomised forced outage (both full and partial outage) distribution.

These schedules have been constructed based on information in the public domain - in particular, the following six key parameters are used in the development of outage schedules and are detailed in the table below.

Table B.1 – Assumptions for Network Development

Full Forced Outage Rate:	Proportion of time per year the unit will experience full forced outages.
Partial Forced Outage Rate:	Proportion of time per year the unit will experience partial forced outages.
Number of Full Outages:	The frequency of full outages per year.
Number of Partial Outages:	The frequency of partial outages per year.
Derated Value:	Proportion of the unit's maximum capacity that the unit will be derated by in the event of a partial outage.
Full Maintenance Schedule:	Maintenance schedule of planned outages (each planned outage has a start and end date between which the unit will be unavailable).

Historical generator availability data has been used in conjunction with the *Advanced Mode* of outage modelling, as this represents the best available (comprehensive) source of information at the time of the study.

Generation Commercial Data

In the development of the chosen trading strategy for each generator across the NEM, some key commercial data has been required. Such data is assembled in the ***2-4-C*** database and includes the following:

- The intra-regional Marginal Loss Factor (MLF);
- Operations and maintenance cost;
- Fuel cost, which has been computed with reference to:
    - Unit heat rate;
    - Fuel heating value, and;
    - Fuel unit price;
- Emission factors for greenhouse gas production.

Energy constraints

Time-varying bid profiles for all hydro power stations including Hydro Tasmania, Snowy Hydro, Southern Hydro, Kareeya and Barron Gorge have been engineered to deliver production patterns corresponding to historical patterns whilst maintaining appropriate price signals.

Competitive bidding strategies for pumped storage hydro plant have been developed to maintain high revenues whilst ensuring energy limitations are not violated.

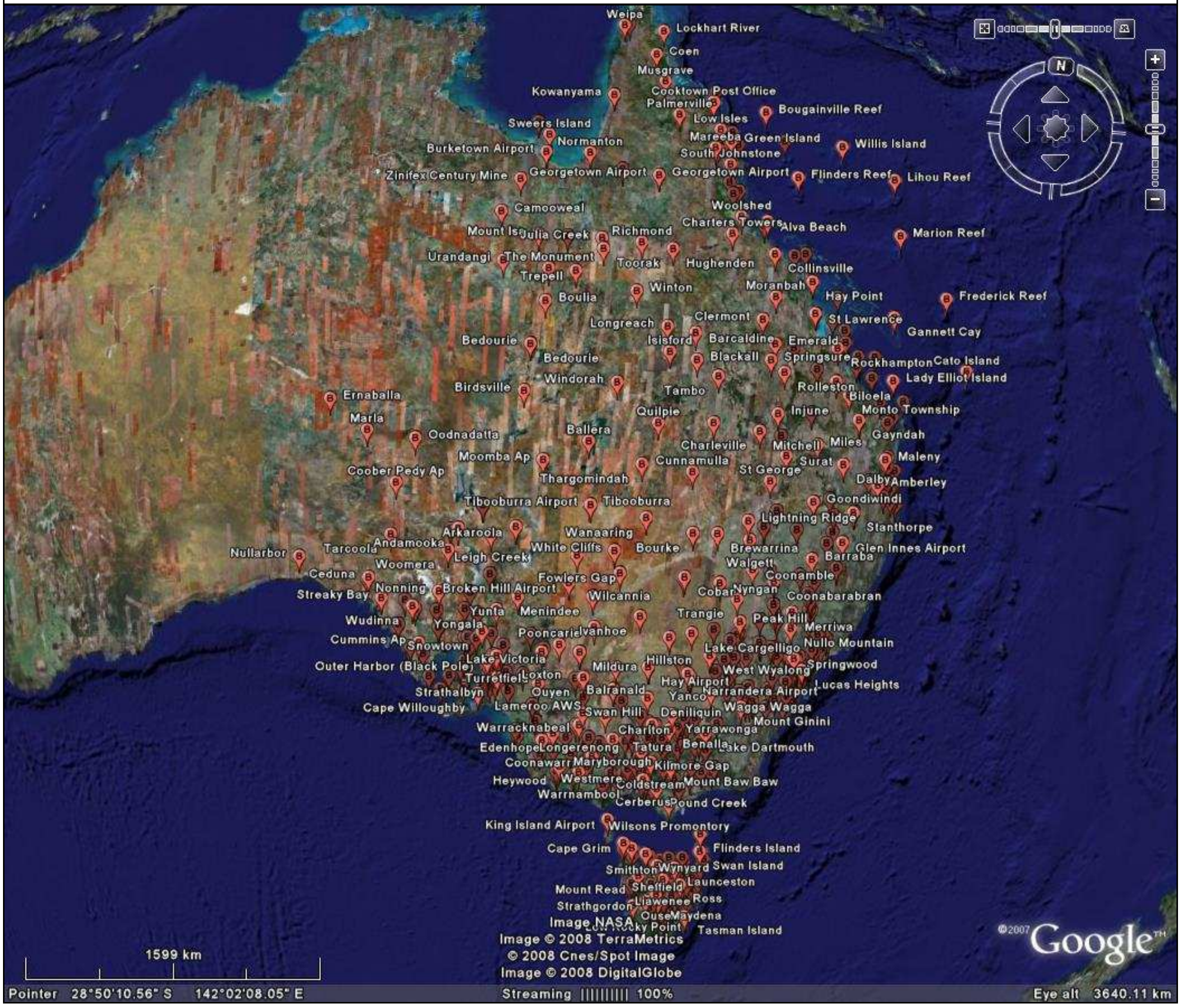
New market entrants

New plant (committed, announced and market entry) is assumed to bid the majority of its capacity at SRMC values.

B.3) Modelling renewable generators

To model the output of wind farms, historical data was sourced from automatic weather stations around Australia from the Bureau of Meteorology and converted to generator outputs using turbine power curves. The locations of the weather stations in eastern Australia are shown in the figure below.

Figure B.2 – Locations of BOM weather stations



The wind data from the Bureau of Meteorology (BOM) weather stations was taken at a variety of elevations (from 1m off the ground to 70m above the ground), and elevation strongly affects wind speeds. The wind at the height of a turbine hub (from 50m to 80m) will be much faster than the wind at ground level, and the amount of the increase in speed is strongly dependent upon many factors, including the type of ground cover (rock, grass, shrubs, trees) and the nature of the weather pattern causing the wind. In addition, the local topography affects wind speeds very strongly (winds tend to be focused by flowing up hillsides, for example).

Therefore, the wind speed at a weather station perhaps 30km distant from a wind farm is likely to be correlated strongly in time with the wind at the site of the turbines, but the absolute scaling of the speeds is highly uncertain. Without more data about each wind site and weather station's local topography and turbine layout it would not be possible to accurately use the wind data to predict the absolute wind speeds at the turbine hubs (such modelling is also very time intensive).

However, it is reasonable to assume that the wind speeds at the weather station will be very highly correlated in time with the wind speeds at the turbine site (analysis of existing wind farm generation profiles compared with the BOM weather station data has shown this to be the case). Therefore, the BOM data provides an excellent way to determine the daily and seasonal variation of wind at different sites, and also the likely correlation between the output of nearby wind farms (which is highly material for transmission congestion).

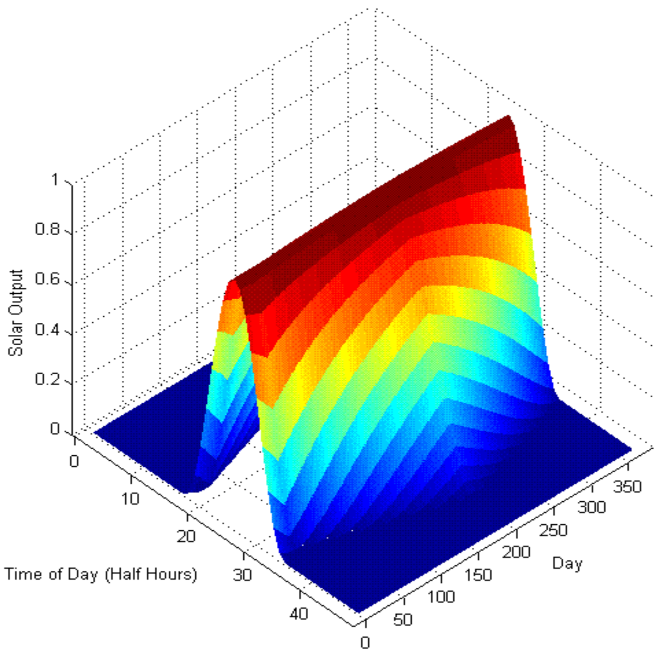
In order to scale the wind appropriately to get realistic generation outputs for each wind farm it has been assumed that wind sites will have (on average) a capacity factor of around 30%. Based on the capacity factors of existing wind farms, and the known capital costs of wind farms this is a reasonable assumption (with capacity factors much lower than 30% they will not cover their long run marginal costs). The wind is scaled, and then a turbine power curve applied to convert the wind speeds into actual generation (this accounts for the fact that the efficiency of turbines varies strongly with wind speed).

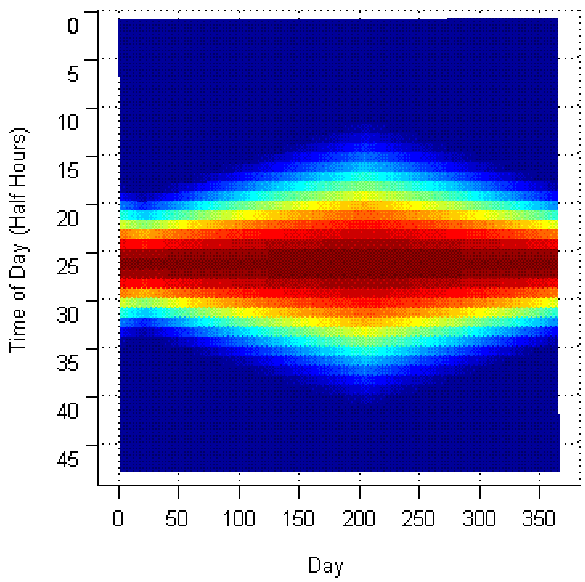
There is very good agreement between the results of this method and the known output of existing wind farms.

Wind farms were bid into the market at $0, with volumes based upon their unit trace outputs in each half hour period.

Solar PV generators were modelled as a Gaussian output that increased to a peak in the middle of the day, with longer hours during the summer. The profile is shown in the figure below. Solar PV generators were bid into the market at $0, with volumes based upon their unit trace outputs in each half hour period.

Figure B.3 – Example Solar PV Generation Profile (by time of day and day of financial year)





Geothermal, solar thermal and bagasse generators can be scheduled, and therefore were assumed to bid into the market in the same way as a conventional generator.

B.4) Assumptions with regard to the Supply System

For the purposes of this description, the supply system is regarded as the physical interconnection between the supply- and the demand-sides of the market.

Transmission Losses

Losses are modelled commercially in either of two ways, in accordance with existing market rules. Treatment is as follows:

Inter-regional Losses

Inter-regional losses over AC interconnectors are modelled using dynamic loss equations supplied by NEMMCO.

Intra-regional Losses

Intra-regional losses are modelled by static, but periodically adjusted, marginal loss factors (MLF) in relation to a Regional Reference Node (RRN). These MLF's are published annually by NEMMCO (and assumed for new stations).

Market forecasting has been completed on a gross basis. Therefore, the energy profiles assumed for each node have incorporated allowance for (transmission and distribution) losses and generator auxiliary energy.

Transmission Limits

For each of the links between the nodes defined in the ***2-4-C*** model, bi-directional limits are dynamically calculated based on the most recent publicly available set of transmission limit equations. This data has been added on the basis of information provided within the relevant planning documentation listed as references in the previous section.

Transmission Asset Development

The following notional transmission limits are indicative of the maximum transmission capacity generally available, however the actual limit at any trading interval is determined through the application of dynamic limit equations.

Table B.2 – Notional Transmission Line Limits

QNI (QLD to NSW)	1078MW
QNI (NSW to QLD)	500MW
Terranora	180MW bi-directional
NSW to Vic	1500MW
Vic to NSW	1500MW
Heywood (VIC to SA)	460MW

Table B.2 – Notional Transmission Line Limits	
Heywood (SA to VIC)	300MW
Murraylink	220MW bi-directional
Basslink (Tasmania to VIC)	610MW
Basslink (Vic to Tasmania)	490MW

Terranora (Gold Coast to Armidale Interconnector)

Terranora is modelled as a regulated market scheduled interconnector. The HVdc interconnector will be dispatched to minimise the net inter-regional loss factor across the QNI and Terranora. As the HVdc link is controllable it will be dispatched to maximise inter-regional competition if this is the optimal dispatch outcome.

Murraylink (Melbourne to South Australia Interconnector)

Murraylink is modelled as a regulated market scheduled interconnector. Murraylink is dispatched in a similar way to Terranora as described above.

Basslink (Latrobe Valley to Tasmania Interconnector)

Basslink is modelled as a bi-directional interconnector. The bidding profile allows for transfers of energy from Tasmania to Victoria during peak times and from Victoria to Tasmania during off-peak times.

B.5) Assumptions with regard to Market Development

Several assumptions are made about the development of the market.

Assumptions of VOLL

The Value of Lost Load (VOLL) was set at the current value of $10,000/MWh.

Developments in Regional Configurations

The potential reconfiguration of pricing regions was not considered in this study.

B.6) Assumptions about Market Externalities

There are numerous externalities that will impact on the operation of the competitive energy market. Several of these are outlined below.

The Impact of Inflation

All monetary figures provided in this report are listed in equivalent January 2008 dollars (net of the impact of inflation).

The Impact of the Goods and Services Tax

Wholesale market prices are quoted exclusive of the Goods and Services Tax (GST). Hence, projections of the wholesale spot price are provided net of GST.